Draft Decision

Review of the Regulatory Test for network augmentations

10 March 2004

File no:
C2001/944

Commissioners:
Samuel
Sylvan
Martin
Willett
McNeill

Contents

Contents i

Executive Summary 1

1. Introduction 6

2. Background 8

2.1 Pre National Electricity Market process 8
2.2 The Customer benefits test 8
2.3 Development of the regulatory test 9
2.4 Network and distributed resources code changes 10
2.5 The regulatory test and TNSP revenue 11

3. Option 1: Minor amendments 14

3.1 Introduction 14
3.2 Summary of Submissions 14
3.3 Commission's Considerations 17

4. Option 2: Definitional changes 20

4.1 Introduction 20
4.2 Summary of Submissions 20
4.3 Commission's Considerations 28

5. Option 3: Competition Benefits 42

5.1 Introduction 42
5.2 Summary of Submissions 42
5.3 Consultants report 46
5.4 Commission's Considerations 48

6. Conclusion 61

Appendix A Submissions 62

Appendix B The Regulatory Test 65

Appendix C Proposed Regulatory Test 70

Appendix D A Definition of Competition Benefits 96

Appendix E Calculating Competition Benefits: A two town example 99

Appendix F Calculating Competition Benefits: A general framework 104

Glossary

CAISO	Californian Independent System Operator
COAG	Council of Australian Governments
Code	National Electricity Code
Commission	Australian Competition and Consumer Commission
CPUC	Californian Public Utilities Commission
Discussion Paper	Discussion Paper - Review of the Regulatory Test
DNSP	Distribution Network Service Provider
EME	Edison Mission Energy
ESAA`	Electricity Supply Association of Australia
Farrier Swier	Farrier Swier Consulting
HHI	Hirschmann-Hefindahl Index
IRPC	Inter Regional Planning Committee
Issues Paper	Issues Paper - Review of the Regulatory Test
LRMC	Long Run Marginal Cost
MNSP	Market Network Service Provider
NDR	Network and Distributed Resources
NECA	National Electricity Code Administrator
NEDF	National Electricity Distributors Forum
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NET	National Electricity Tribunal
NPV	Net Present Value
NSP	Network Service Provider
Opex	Operating Expenditure
RNPP	Tasmanian Reliability and Network Planning Panel

RSI	Residual Supply Index
SCL	Stanwell Corporation Limited
SHT	Snowy Hydro Trading Pty Ltd.
SNI	South Australia – New South Wales Interconnector
SOO	Statement of Opportunities
SPI	SPI PowerNet
SRMC	Short Run Marginal Cost
TNSP	Transmission Network Service Provider
VENCorp	Victorian Energy Networks Corporation
VoLL	Value of Lost Load
USE	Un-served Energy
WACC	Weighted Average Cost of Capital

Executive Summary

Introduction

Since the promulgation of the regulatory test in December 1999, the Australian Competition and Consumer Commission (Commission), in conjunction with the National Electricity Code Administrator (NECA), made a commitment to review the current framework for essential new investment. For its part, the Commission initially released an Issues Paper on 10 May 2002 (Issues Paper) highlighting a number of concerns raised by interested parties with the operation of the regulatory test. From submissions received, the Commission identified three options for the development of the regulatory test, which it outlined in a Discussion Paper released on 5 February 2003 (Discussion Paper). The options canvassed included:

- Option 1 – maintaining the current regulatory test with minor modifications to ensure consistency between the regulatory test and the National Electricity Code (code);
- Option 2 – providing a number of definitions to be used by transmission and distribution businesses when applying the regulatory test in an attempt to define and clarify elements of the regulatory test, and ensure a nationally consistent application;
- Options 3 – considering ways of ensuring the regulatory test includes the benefits of increased competition.

Taking into account submissions received from interested parties in response to its Discussion Paper and the outcomes of the Market Review Forum held on 28 July 2003, which covered issues relating to competition benefits, the Commission proposes a number of refinements to the regulatory test. These are discussed below.

Proposed amendments to the regulatory test

Since the promulgation of the regulatory test in December 1999, there have been a number of developments which have affected the framework governing the operation of the regulatory test. These developments include:

- the Network and Distributed Resources (NDR) code changes authorised by the Commission on 13 February 2002;
- the National Electricity Tribunal's (NET) decision on South Australia – New South Wales Interconnector (SNI) for which a regulatory test was applied by the National Electricity Market Management Company (NEMMCO);
- the Victorian Supreme Court's decision on aspects of the NET's decision;
- the Commission's work on the Murraylink Conversion application; and
- the Ministerial Council on Energy's communiqué on reforms to the energy market.

The Commission has considered these issues and comments of interested parties in response to the Discussion Paper in its proposed refinements to the regulatory test. The Commission also received a number of submissions which raise concerns about the framework in which the regulatory test operates. This Draft Decision only deals with the mechanics of the regulatory test. The framework in which the regulatory test operates and its use by the Commission in setting a Transmission Network Service Provider's (TNSP) revenue is the subject of another paper entitled "Supplementary Discussion Paper to the Review of the

Statement of Regulatory Principles: Capital Expenditure Framework" which is being released in conjunction with this paper[1]. Submissions which raise issues with the framework in which the regulatory test operates are therefore not addressed in this Draft Decision.

Option 1: Minor amendments

In the Commission's Discussion Paper, it outlined a number of amendments to the regulatory test to ensure consistency between it and the code. The NDR amendments introduced a number of changes to Chapter 5 of the code, which have resulted in apparent inconsistencies between the code and the regulatory test. There are four broad areas where the regulatory test and the code are now inconsistent:

- the role and responsibilities of NEMMCO, TNSPs, the Inter-regional Planning Committee (IRPC) and the Commission in relation to planning and approval of new transmission network investments;
- reference to inter and intra regional augmentation in the regulatory test compared to new small and new large network assets;
- the definition of a reliability augmentation which encompasses service standards linked to the technical requirements of schedule 5.1 of the code as well as jurisdictional obligations; and
- other cross-referencing between the regulatory test and the code.

In its Discussion Paper the Commission outlined amendments to ensure consistency with those areas of the code which have changed. All parties who made submissions in response to this section of the Discussion Paper agree with the principle of aligning the regulatory test with the code. Therefore, the Commission proposes amending the regulatory test along the lines raised in its Discussion Paper.

Some interested parties suggest that an element of the regulatory test preamble is unnecessary given that the code already sets out the roles and responsibilities of those parties who are required to apply the regulatory test. The Commission concurs with this view and proposes deleting this section of the preamble.

In its Discussion Paper the Commission also raised questions regarding the proposed safety net afforded to replacement and refurbishment expenditure which is voluntarily assessed against the regulatory test as well as the threshold for new small and new large network assets. The responses were mixed on these issues. Given that these issues relate to the framework in which the regulatory test operates, the Commission is of the opinion that they are best deal with in its capital expenditure framework paper.

Option 2: Definitional changes

In its Discussion Paper, the Commission outlined a number of definitional amendments to the regulatory test in an attempt to clarify those elements that may currently be considered ambiguous and open to interpretation. The Commission proposed to define alternative

1 ACCC, Supplementary Discussion Paper to the Review of the Statement of Regulatory Principles: Capital Expenditure Framework, 10 March 2004

projects, committed projects and anticipated projects as well as provide a non-exhaustive list of market benefits and costs, and clarify the use of the discount rate and VoLL.

There was general support for defining some of the terms used in the regulatory test. However, there were concerns raised that making the test too prescriptive or too narrow may unintentionally exclude valid and practicable alternative projects as well as exclude real and material benefits and/or costs from the regulatory test assessment. Concerns were also raised about using definitions which cover both the reliability limb and the non-reliability limb of the regulatory test, for example, when defining alternative projects.

Taking into account the views raised by interested parties, the Commission considers that it is appropriate to amend and define particular terms used in the regulatory test which it considers will provide greater guidance to Network Service Providers (NSPs). These definitions and terms come from the Commission's consideration of the views expressed by interested parties, the NET and Victorian Supreme Court's decision on SNI, as well as other regulatory test applications. The amendments relate to:

- *Alternative projects* – the Commission considers that this definition should incorporate two limbs to cover both reliability and non-reliability augmentations;
- *Benefits and costs* – this is intended to provide guidance on the type of benefits and costs that the proponent should consider when applying the regulatory test. This guide is not intended to be exhaustive;
- *Committed projects and anticipated projects* – these definitions are derived from NEMMCO's definition of a committed project;
- *VoLL* - in defining this term, the Commission proposes to recognise the value of customer reliability (VCR) as an input but recommends that the sensitivity analysis should consider both VoLL and VCR estimates where practicable;
- *Discount rate* - the Commission still considers that a commercial discount rate is appropriate for the purposes of the regulatory test but proposes the use of a formula for calculating the discount rate;
- *Market failure test* - the Commission proposes to remove note 7 of the regulatory test;
- *Sensitivity Analysis* - the Commission proposes including a list that should be considered in the sensitivity analysis.

While the Commission believes that these terms improve NSPs and other parties' understanding of the regulatory test it believes that there is still sufficient flexibility to enable the regulatory test to evolve over time.

Option 3: Competition benefits

The third option proposed by the Commission in its Discussion Paper addressed the issue of "competition" benefits. The biggest criticism of the regulatory test by some market participants is that it does not recognise "competition" benefits. From the submissions received in responses to the Discussion Paper there are a wide range of views on how "competition" benefits should be defined. For example should "competition benefits" only deal with the "welfare triangle" or should it include wealth transfers. Most parties support the economic efficiency interpretation of competition benefits. There were fewer parties who supported including wealth transfers.

In promulgating the regulatory test the Commission must have regard to the need to ensure that the regulatory test is consistent with the principles set out in Chapter 6 of the code. The Commission believes that it is clear that Chapter 6 of the code emphasises that the regime it administers must provide for the *efficient* operation, provision and expansion of transmission facilities. Therefore, in keeping with the code's objectives the Commission considers that the calculation of "competition" benefits must be limited to considering those benefits arising from increases in efficiency from the expansion of transmission networks.

In developing a workable definition, the Commission has looked to the effects of an augmentation on generator bidding behaviour. The Commission proposes defining "competition" benefits as the difference arising from the following two network scenarios:

- the augmented network with bidding assumed to be the same as in the status quo network; and
- the augmented network with bidding which accurately and fully reflects any market power in the augmented network.

In its Discussion Paper, the Commission outlined several options on how "competition" benefits may be calculated. These options were:

- Market simulations – which utilises the modelling currently required under the regulatory test;
- Powerlink's Public Benefits Competition test – which utilises market modelling but is triggered in "Public Interest" situations;
- Hirschmann-Hefindahl and modified Hirschmann-Hefindahl indices – which would aim to apply the tools used by competition authorities worldwide in assessing merger applications;
- A Residual Supply Analysis – using the techniques currently under consideration by the Californian ISO (CAISO);
- Commercial Benefits Analysis – utilising the Inter-Regional Settlements Residues as a proxy for "competition" benefits; and
- Stanwell Competition Index – which uses qualitative tools for the assessment of "competition" benefits.

To assist it in its work on how to best calculate "competition" benefits, the Commission engaged Farrier Swier Consulting (Farrier Swier) to consider the various options outlined in the Discussion Paper and to report on the issues arising from the practical implementation of the various approaches to the measurement of competition benefits. Of these methods Farrier-Swier recommends, and the Commission concurs, that the only realistic way of calculating "competition" benefits is by using market simulations techniques.

There are a number of methodologies that can be used by TNSPs to model "competition" benefits using simulations. The following were outlined by Farrier-Swier in its paper:

- Cournot-Nash;
- Bertrand; and
- Supply Function Equilibrium.

The Commission is not in a position at this stage to advocate one approach over the others. However, it notes that Frontier Economics, in a consultancy for TransGrid, provides a worked one-year example of the application of Nash modelling to a 400MW interconnector between the Snowy and Victorian regions of the NEM. The results of its analysis were “competition” benefits of $31 million.

The Commission will be undertaking further work and will engage a consultant to conduct modelling on designated projects. The results of the consultant’s analysis will be published and interested parties will be invited to comment on the outcome.

Summary

The Commission proposes to incorporate all three suggested amendments. For comparative purposes, a copy of the current regulatory test is provided in Appendix B, and a copy of the revised regulatory test outlining the proposed amendments is provided for in Appendix C. The Commission has also included a list comparing its proposed amendments to the regulatory test with the current regulatory test.

Comments provided by interested parties in response to this Draft Decision will be incorporated into the Commission’s Final Decision, where if necessary, the Commission will promulgate changes to the regulatory test in accordance with clause 5.6.5A of the code.

1. Introduction

Under clause 5.6.5A of the National Electricity Code (code), the Australian Competition and Consumer Commission (Commission) is responsible for the promulgation of the regulatory test. Clause 5.6.5A of the code states:

> The *ACCC* must:
>
> (a) promulgate the *regulatory test* (and may vary the *regulatory test* from time to time);
> (b) have regard to the need to ensure that the *regulatory test* is consistent with the basis of asset valuation determined by the *ACCC* for the purposes of clause 6.2.3; and
> (c) have regard to the obligations imposed on *Network Service Providers* to meet the *network* performance requirements set out in schedule 5.1 and relevant legislation and regulations of a *participating jurisdiction*, in developing and maintaining the *regulatory test*.

On the 15 December 1999, the Commission promulgated the regulatory test in accordance with the provisions of the code.

As part of its commitment to review the current framework for essential new investment, the Commission initially released an Issues Paper on 10 May 2002, which highlighted a number of concerns raised by interested parties with the operation of the current regulatory test. From the submissions received on the Issues Paper, the Commission identified three options for the development of the regulatory test. The three options were outlined in the Discussion Paper which was released on 5 February 2003. These included:

- Option 1 – maintaining the current regulatory test with minor modifications to ensure consistency between the regulatory test and the National Electricity Code (code);
- Option 2 – providing a number of definitions to be used by transmission and distribution businesses when applying the regulatory test in an attempt to define and clarify elements of the regulatory test, and ensure a nationally consistent application;
- Options 3 – considering ways of ensuring the regulatory test includes the benefits of increased competition.

A Competition Benefits and Market Review Forum was held on 28 July 2003 which allowed for discussion of issues relating to the regulatory test and competition benefits.

In response to the Discussion Paper and issues discussed at the Market Review Forum, the Commission received 52 submissions. A list of the parties who provided submissions is outlined in Appendix A. Submissions to the Discussion Paper are available on the Commission's website (www.accc.gov.au).

Taking into account submissions received from interested parties in response to its Discussion Paper, the Commission proposes a number of refinements to the regulatory test. For comparative purposes, a copy of the current regulatory test is provided in Appendix B, and a copy of the revised regulatory test outlining the proposed amendments is provided in Appendix C, were a table outlining the changes is also included . The Commission invites interested parties to consider and comment on this Draft Decision.

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**.

Comments provided by interested parties will be incorporated into the Commission's Final Decision, where, if necessary, in accordance with clause 5.6.5A of the code, the Commission will promulgate changes to the regulatory test.

2. Background

This chapter provides background on the development of the regulatory test and processes for the development of new network investment decisions.

2.1 Pre National Electricity Market process

Prior to the commencement of the reforms to the electricity sector state run enterprises were charged with the responsibility for planning and constructing all elements of the electricity supply chain. Transmission networks were built to meet the supply and demand needs of the States. Consequently, planning and investment decisions were not designed around the operation of a competitive "market" in electricity.

With the introduction of the National Electricity Market (NEM), network investment decisions needed a decision making framework that recognised the operation of the market and one that ensured both prudency and competitive neutrality. This approach fits with the overall regulation of networks to ensure that the open access regime of the NEM promotes competition and access while providing asset owners and operators with a reasonable risk adjusted revenue stream to fund their investment.

The NEM incorporates market related aspects designed to encourage network investment where such investment produces lower losses and minimises energy price variability between regions. One of the criticisms of the current market design is that the existing regions are largely based along state boundaries, with the exception of the Snowy region. Ideally the network pricing arrangements would provide price signals, which reflect the extent of congestion or spare capacity and provide efficient investment signals. Hence the form of regulation and its reach is influenced by the extent to which network investment decisions are influenced and even controlled by the market.

Unless the network pricing arrangements provide pricing signals that encourage network investment the market will continue to require regulatory approval for new investment. In the NEM, the relevant regulators provide the regulatory approval. Regulated network investment will, therefore, only receive a return if it passes the criterion set out in a regulatory test. The regulatory test was developed in response to concerns raised by the National Electricity Market Management Company (NEMMCO) in its application of the Customer benefits test.

2.2 The Customer benefits test

The Customer benefits test was designed to ensure that network investment would only be undertaken if customers benefited from that investment.

In 1998, NEMMCO was asked to perform an assessment of the proposed interconnector between South Australia and New South Wales (SANI) against the criterion set out in the Customer benefits test. The objective was to ensure that the project was justified under the National Electricity Code (code) and would enter the relevant regulated asset base.

In its review, published in June 1998, NEMMCO noted that the code contained some ambiguities. In particular, it noted that some clauses referred to public benefit and others referred to Customer benefit, with customer being defined in the code as wholesale market customers, rather than customers at large. NEMMCO also noted several issues associated with identifying and measuring certain costs and benefits. While NEMMCO noted that if SANI was assessed against a public interest test, looking at benefits to producers and consumers it would have passed, however under the customer benefits test SANI was not justified. NEMMCO also concluded that the test, as it stood, might make it difficult for any inter-regional augmentation to satisfy the criterion.

Reflecting this concern, the NSW Government lodged this issue on NEMMCO's Issues Register requiring it to be resolved prior to the commencement of the NEM. Consequently, the Commission was asked, as an independent party, to review the test and recommend changes to the test to overcome the perceived inadequacies.

2.3 Development of the regulatory test

The Commission engaged Ernst & Young to assist it in conducting its review. The Commission published the Ernst & Young report in March 1999. On the basis of that report, the Commission published a preliminary view of the regulatory test in April 1999. That paper acknowledged the merit in changing the test from a Customer benefits test to a market benefit test based on maximising net public benefits.

On 23 July 1999, NECA sought authorisation of amendments to the code, which included changes to replace the existing Customer benefits test with a regulatory test to be determined by the Commission. The amendments also required all network service providers (including both transmission network service providers (TNSPs) and distribution network service providers (DNSPs) to consult with interested parties when applying the regulatory test in deciding which network augmentations should proceed. The consultation included examining, amongst other things, alternative generation and demand side options to determine the option that satisfied the regulatory test, while meeting the technical requirements (reliability) of schedule 5.1 of the code. The amendments also required the Inter Regional Planning Committee (IRPC) and NEMMCO to apply the regulatory test when considering possible system augmentations. The Commission authorised the code changes on 20 October 1999[2].

The Commission adopted a parallel process with the code change consultation for developing its preliminary views on the regulatory test and sought additional submissions. It released a draft regulatory test on 22 September 1999 and, following further consultation, finalised the regulatory test in December 1999.

In developing the regulatory test the Commission relied on the two key principles of economic efficiency and competitive neutrality. Consequently, the Commission based the regulatory test on the traditional cost-benefit analysis framework but with a number of clarifications to limit any adverse impacts that regulated network investments might have on the competitive processes in the contestable parts of the industry. One of the recommended

2 ACCC; Applications for authorisation: Market Operations for Y2K, Regulated Interconnectors and Augmentations and System Security Compensation; 20 October 1999.

changes to the test was to remove the volatility inherent in the Customer benefits test and ensure even-handed treatment between network and non-network investment. That is, to extend the neutrality in the code between network and non-network alternatives such as generation, demand side or unregulated network investment to the regulatory test.

Key features of the regulatory test include:

- reference to net public benefits rather than the original net customer benefits;
- calculating the net benefits of the various options with reference to the underlying economic cost savings and not with reference to pool price outcomes which may be distorted by market participants exercising market power;
- excluding from the analysis the costs and benefits associated with competitive, non-electricity, market activities as the test is to be used to assess the merits of regulated electricity network assets;
- including in the analysis only those environmental impacts that governments or their environment agencies have sought to redress;
- using the discount rate that would be used by participants in the contestable markets; and
- relying on forecasts of future market behaviour based on both assumptions of a competitive market as well as actual market behaviour.

2.4 Network and distributed resources code changes

At the time of NEMMCO's working group, NECA had already submitted amendments to the code, the NDR package, which changed the respective roles of the IRPC, NEMMCO and the Commission in relation to assessing network investments.

The NDR amendments introduced two major changes to the code. Firstly, the code amendments devolved responsibility for the application of the regulatory test relating to inter-regional augmentations from NEMMCO to TNSPs. Secondly, the amendments removed the distinction between inter and intra-regional network augmentations and replaced it with a distinction between new large and small network assets. A new large network asset is defined as an augmentation that a TNSP estimates will require a total capitalised expenditure in excess of $10 million. A new small network asset is an augmentation that a TNSP estimates will require a total capitalised expenditure in excess of $1 million but not greater than $10 million.

While the proposals were developed with transmission network planning in mind, NECA modified the code to ensure that the existing provisions and obligations on Distribution Network Service Providers (DNSPs) were maintained but not extended. That is, DNSPs must continue to carry out economic cost effectiveness analyses of options that satisfy the regulatory test where it has identified necessary augmentations in its annual planning review[3].

3 Clause 5.6.2(a2)(g)

2.5 The regulatory test and TNSP revenue

2.5.1 Pre NDR code changes

Prior to the NDR code changes, Network Service Providers (NSP) were required under the then clause 5.6.2 to apply the regulatory test to transmission system or distribution system augmentations. NEMMCO and the IRPC where required to apply the regulatory test to augmentation options in accordance with the then clause 5.6.5, and to proposed new interconnectors in accordance with the then clause 5.6.6.

In terms of disputing the outcomes of the regulatory test, a code participant could have disputed the recommendations of the report to the Dispute Resolution Panel, under chapter 8 of the code, for any proposal which was reasonably likely to change the use of system service charges by more than 2% at the subsequent price review. NEMMCO's determination of whether an interconnector satisfied the regulatory test was a reviewable decision.[4]

The regulatory test and regulated revenue

Where an NSP assessed an augmentation under the regulatory test, clause 5.6.2(k) of the code implied that the cost of the asset which was deemed to pass the regulatory test was rolled into the Network Service Provider's asset base. The then clause 5.6.2(k) stated:

> "…the relevant Network Service Provider must arrange for the project to be available for service by the agreed time and the Network Service Provider must include the cost of the relevant assets in the calculation of transmission service and distribution service prices determined in accordance with Chapter 6 of the Code."

Further, where the NSP decided to implement a generation option, the NSP was required to include the cost of the network support service in the calculation of transmission service and distribution service prices determined in accordance with Chapter 6 of the code.

Where NEMMCO determined that an augmentation was justified, the code specifically stated that the cost of the asset was to be included in the determination of the revenue cap. The then clause 5.6.5(m) stated:

> "If NEMMCO determines that an augmentation of a network is justified, then the Network Service Providers whose networks would require augmentation may arrange for the augmentation project to be undertaken and the cost of the relevant assets are to be included in the determination of the revenue cap in accordance with Part B of Chapter 6."

However, the outstanding issue in both cases was at what value should the asset be rolled into the TNSP's regulatory asset base.

4 A decision of *NEMMCO* or *NECA* that is specified as a reviewable decision is one which pursuant to the *National Electricity Law*, can be reviewed by the *National Electricity Tribunal*.

2.5.2 NDR code changes

Chapter 5 of the code now requires TNSPs to conduct a code consultation process when it proposes to augment it network, and apply the regulatory test to such a proposal. Before proceeding with its regulatory test assessment the TNSP must consider whether the proposed augmentation is driven by reliability reasons, in which case it applies the reliability limb of the regulatory test, or economic/non-reliability reasons, under which it applies the market benefits limb of the regulatory test. The length and rigour of the TNSPs consultation process will depend on whether the proposed augmentation is a new small network asset or new large network asset.

In the case of new small network assets the TNSP must consult on the augmentation in its Annual Planning Report. The Annual Planning Report must contain an analysis of whether a new small network asset satisfies the regulatory test. Where a new small network asset is not identified in its Annual Planning Report the TNSP must prepare a report that is to be published and circulated to all code participants and interested parties. While there is no avenue of appeal against this analysis, the Commission is required to take into account the relevant report and all material submitted during the consultation process in setting the TNSP's revenue cap.

The process for the construction of a new large network asset is lengthier and more onerous. In the case of a new large network asset the applicant must publish a notice, which in accordance with clause 5.6.6(b), sets out a detailed description of:

- the proposed new large network asset;
- the reason for proposing the new large network asset;
- all reasonable network and non-network alternatives;
- all relevant technical details, including the construction date and timetable;
- the ranking of the new large network asset against the alternatives;
- a technical report by the IRPC if it is reasonably likely to have a material inter-network impact; and
- detailed analysis of why the new large network asset satisfies the regulatory test, and/or why it is a reliability augmentation.

The code also requires the TNSP to publish a final report setting out its conclusion on these issues, with a summary of the report to be published on NEMMCO's website. The grounds for appeal to the Dispute Resolution Panel (DRP) are set out in clause 5.6.6(h) of the code, which includes:

- possible alternatives considered and their rankings;
- whether the new large network asset will have a material inter-regional impact;
- the basis on which the applicant has assessed that the new large network asset satisfies the regulatory test; and
- whether the new large network asset is a reliability augmentation and whether it satisfies the IRPC criteria.

The DRP must publish a statement of reasons which must then be incorporated into the TNSP's report. The findings in this report can then be disputed to the Commission on whether the asset satisfies the regulatory test, provided that the asset is not a reliability augmentation.

The regulatory test and regulated revenue

The code no longer specifies that an augmentation that is deemed to satisfy the regulatory test must be rolled into the TNSP's regulatory asset base. However, the Commission will still place significant weight on the fact that the regulatory test has been satisfied. Practically, this could mean that where the scoping of the project has changed significantly or in the Commission's opinion the regulatory test was not applied properly, the Commission could rely on other criteria to determine whether to roll the asset into the regulatory asset base.

The Commission received a number of submissions which raise concerns about the framework in which the regulatory test operates. This Draft Decision only deals with the mechanics of the regulatory test. The framework in which the regulatory test operates and its use by the Commission in setting a Transmission Network Service Provider's (TNSP) revenue is the subject of another paper entitled "Supplementary Discussion Paper: Capital Expenditure Framework" which is being released in conjunction with this paper. Submissions which raise issues with the framework in which the regulatory test operates are therefore not addressed in this Draft Decision.

3. Option 1: Minor amendments

3.1 Introduction

In its Discussion Paper, the Commission outlined a number of amendments to the regulatory test to ensure consistency between it and the code. The NDR amendments introduced a number of changes to Chapter 5 of the code, which have resulted in apparent inconsistencies between the code and the regulatory test. There are four broad areas where the regulatory test and the code are now inconsistent:

- the role and responsibilities of NEMMCO, TNSPs, the IRPC and the Commission in relation to planning and approval of new transmission network investments;
- reference to inter and intra regional augmentation in the regulatory test compared to new small and new large network assets;
- the definition of a reliability augmentation which encompasses service standards linked to the technical requirements of schedule 5.1 of the code as well as jurisdictional obligations; and
- other cross-referencing between the regulatory test and the code.

The inconsistency in the terminology between the regulatory test and the code could create confusion for NSPs when applying the regulatory test and could potentially create an avenue for dispute. The Commission notes that realigning the regulatory test with the code will provide uniformity and less confusion in the interpretation and application of the regulatory test across the NEM.

The following section provides a summary of submissions in response to the Commission's Discussion Paper, and outlines the Commission's consideration of the amendments to the regulatory test reflecting comments made by interested parties in response to the Commission's proposed Option 1 amendments outlined in the Discussion Paper.

3.2 Summary of Submissions

In general, submissions made in response to this section of the Discussion Paper concur that the regulatory test should be made consistent with the code to reduce uncertainty and ambiguity. They submit that inconsistency between the regulatory test and the code makes it difficult for NSPs to know what they need to comply with. The responses were mixed on the proposed safety for replacement and refurbishment expenditure voluntarily assessed against the regulatory test and the threshold for new small and new large network assets. A summary of these submissions follows.

3.2.1 Aligning the Regulatory Test with the National Electricity Code

While interested parties who made submissions in response to this section of the Discussion Paper agreed with the principle of aligning the regulatory test with the code they differed on how the amendments should be made.

The ECCSA and EUCV in a joint submission note that the changes proposed by the Commission are sensible and reflect the code as amended. While Powerlink supports the proposed amendments in the Commission's Discussion Paper it suggests that the wording in the preamble be amended to:

"the regulatory test is to be applied to :

(a) transmission system or distribution system augmentation proposals in accordance with clause 5.6.2 of the code (augmentation)

(b) by NSPs to new small network assets identified under clause 5.6.2 and pursuant to clause 5.6.6A of the Code (new large network assets)

(c) by NSPs to new large network assets pursuant to clause 5.6.6 of the code (new large network assets)"

While TransGrid suggests that the preamble could be amended along the following lines:

"The regulatory test is to be applied:

(a) to transmission systems or distribution system augmentation proposals in accordance with clause 5.6.2 of the code (augmentation);

(b) by TNSPs to *new small network assets* identified under clause 5.6.2A(b)(5)(iii) and pursuant to clause 5.6.6A of the Code; and

(c) by applicants to *new large network assets* pursuant to clause 5.6.6(b) of the Code.

In this test, augmentation, *new large network assets* and *new small network assets* are called *proposed augmentations*."

TransGrid suggests that an alternative approach is for the Commission to consider omitting this section of the preamble altogether. It notes that the code itself sets out when the regulatory test should be applied, and argues that replicating these code references in the regulatory test means that the test may need to be updated again if the code provisions are amended in the future.

The National Electricity Distributors Forum (NEDF) suggests that the Commission's amendments which reference NSPs should explicitly recognise that the new small and new large network asset code provisions only relate to TNSPs.

TransGrid also notes that to be consistent with the NDR code changes the wording of limb (a) of the regulatory test should be changed to:

"(a) in the event the *augmentation* is proposed as a *reliability augmentation* – the *augmentation* minimises the net present value of the *cost* of meeting the relevant network performance requirements."

In contrast both VENCorp and Gallaugher and Associates (Gallaugher) argue that the Commission should consider eliminating the reliability limb of the regulatory test. VENCorp suggests that parts (a) and (b) of the regulatory test should be consistent with one another, and should be expected to deliver the same decision signals when applied to the same augmentation. VENCorp proposes that the definition of "reliability augmentation" and any associated standards in schedule 5.1 of the code should be undertaken by an independent body, and clarified as a matter of urgency. Gallaugher suggests that an alternative would be to have a consistent set of national standards. VENCorp notes that while the IRPC is required to publish objective criteria for reliability augmentations, it is compromised because it is made up of TNSPs that have a commercial interest in building and owning networks.

Powerlink and TransGrid note that the regulatory test currently states that a proposed augmentation maximises market benefit if it achieves a greater market benefits or minimises the cost in “most (although not all) credible scenarios”. They suggest that this should be changed to “most (although not necessarily all) credible scenarios”.

Powerlink also states in regard to note 7 (c) of the regulatory test that the test requirement that new interconnectors must not be determined to satisfy this test if start of construction is within 18 months of the project’s need first being identified in a public report. Powerlink notes that this is an unjustified bias towards non-regulated interconnectors.

TransGrid believes references to the term “project” in the test should make clear the distinction between those that refer to alternative options and those that refer to future developments that form part of market development scenarios.

VENCorp also suggests that parts (a) and (b) of the test would be further clarified if paragraphs (e) and (f) of the test were amended to:

(e) a proposed augmentation maximises the market benefits, <u>pursuant to part (a) of the test</u> if it achieves a greater market benefit in most(although not all) credible scenarios; and

(f) an augmentation minimises the cost, <u>pursuant to part (b) of the test</u> it achieves a lower cost in most (although not all) credible scenarios.

3.2.2 Replacement and refurbishment capital expenditure

ElectraNet and Transend agree with the Commission’s statement that the code only requires that the regulatory test be applied to network augmentations. However they disagree with the Commission’s view that in the case where a replacement or refurbishment results in an augmentation that that part which augments the network should be assessed against the regulatory test. Instead, they contend that incidental augmentations arising from the replacement of network elements should not be subjected to the regulatory test.

Regarding the Commission’s proposal to have TNSPs apply the regulatory test to asset replacements as a ‘safety net’ against optimisation, SPI Powernet, VENCorp, Powerlink and the NEDF argue that asset replacements should not be subject to the regulatory test. Some of these parties, however, note that it may be difficult in practice to distinguish between replacement of existing capability and investment in increased capability.

In contrast the EUCV/ECCSA, Hydro Tasmania and NRG Flinders contend that where replacement or refurbishment is done with a view to increase capacity it should be subject to the regulatory test.

Gallaugher proposes a different approach which has the Commission considering distinguishing between economically justified investments and the marginal component of incremental interventionist type investment rather than classifying the full project cost of a regulated network investment proposal as a reliability investment or augmentation.

3.2.3 New small and new large network assets thresholds

Transend, ElectraNet, Powerlink, TransGrid, The NSW Ministry of Energy and Utilities, and the NEDF are all of the view that the present thresholds are too low. Of these submissions, ElectraNet, Powerlink, TransGrid, the Minister of Energy and Utilities suggest that the threshold for a new small network asset should be raised from $1million and $10million to between $5million and $7million for new small network assets and greater than $25 million for a new large network asset.

In contrast the EUCV/ECCSA, RNPP, Energex and Gallaugher believe that the current values are adequate. Gallaugher further notes that the impact of an augmentation on the market should determine how the test should be applied, rather than its capital cost.

3.3 Commission's Considerations

The Commission considers that maintaining the regulatory test in its current form, albeit with some amendments, is appropriate. As noted in several submissions, the regulatory test will evolve over time and become more determinative as precedents are set through its application as well as any disputes settled through the code's dispute resolution processes. The main changes the Commission proposes to make to the regulatory test are discussed below.

3.3.1 Aligning the Regulatory Test with the National Electricity Code

The Commission has noted that due to changes to the code, it has become necessary to realign the regulatory test with the code to make it consistent with those changes. Such realignment may continue to be necessary following any subsequent changes to the code.

The Commission agrees with TransGrid that the preamble to the regulatory test duplicates the code in setting out the roles and responsibilities of various parties in relation to the planning and approval of new transmission network investments. Therefore the Commissions proposes deleting the section of the preamble.

A number of parties addressed the issue of limb (a) of the regulatory test and the definition of a reliability augmentation under the code. Limb (a) of the regulatory test states:

> An *augmentation* satisfies this test if –
>
> in the event the *augmentation* is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code – the *augmentation* minimises the net present value of the *cost* of meeting those standards;

Following the NDR code changes the code defines a reliability augmentation as:

> A *transmission network augmentation* that is necessitated solely by inability to meet the minimum *network* performance requirements set out in schedule 5.1 or in relevant legislation, regulations or any statutory instrument of a *participating jurisdiction*.

Obviously the code's definition of a reliability augmentation is broader than the reliability augmentation which can currently be considered under limb (a) of the regulatory test. The Commission notes that the conflicting requirements of the regulatory test and the code may cause confusion and potentially open an avenue for dispute. The Commission supports the views expressed by VENCorp that all transmission investment be undertaken with reference to its economic need. However, it notes that its obligation under clause 5.6.5A of the code requires that it:

> have regard to the obligations imposed on *Network Service Providers* to meet the *network* performance requirements set out in schedule 5.1 and relevant legislation and regulations of a *participating jurisdiction*, in developing and maintaining the *regulatory test*.

The Commission must recognise the obligations that are imposed on TNSPs by the code and jurisdictional legislation and therefore proposes to amend limb (a) of the regulatory test to reflect the code's requirements. If a proposed augmentation does not meet the codes definition of a reliability augmentation, then that augmentation should be assessed under the market benefits limb, limb (b) of the regulatory test.

Regarding TransGrid and Powerlink's proposals to include the term "necessarily" in the phrase "most (although not all) credible scenarios", the Commission agrees that this was indeed its intention. This has brought the Commission to consider whether these terms are the most appropriate to use. Economic theory suggests that the project which satisfies the regulatory test should have the highest (lowest) expected present value in the case of market benefit augmentations (in the case of reliability augmentations). However, the Commission believes that an approach based on a project satisfying the criteria in a majority of reasonable scenarios will minimise the risk of disputes on the weighting given to particular scenarios. The Commission believes that there is some advantage from replacing the word "credible" with "reasonable" and the term "most" with "majority". The Commission will, however, continue to monitor whether moving to expected present values is appropriate.

The Commission also believes that there is some advantage in reordering the structure of the regulatory test. The Commission believes that its proposed amendments to the structure of the regulatory test will aid clarity without changing its intent. Its proposed changes address VENCorp's suggestions.

The Commission considers the two points raised in relation to the definition of *projects* noted by TransGrid and the 18 month construction lag time limit raised by Powerlink, in Chapter 4 of this Draft Decision.

3.3.2 Replacement and refurbishment capital expenditure

As noted in the Discussion Paper, and supported by a number of parties, the regulatory test is only required to be applied to network augmentations, not to replacement or refurbishment projects. In instances where an asset replacement or refurbishment simultaneously augments the network the Commission believes that the code is clear and requires that the regulatory test must be applied to that part which augments the network.

In terms of the regulatory test acting as a safety net for asset replacements is proposing to defer this issue pending the outcome of its review of the capital expenditure framework.

3.3.3 New small and new large network assets thresholds

The Commission has considered the views of the numerous parties who have made submissions. However, at this stage the Commission is also proposing to defer this issue pending the outcome of its review of the capital expenditure framework.

<u>Proposed amendment to the regulatory test</u>

Taking into account comments provided by interested parties, the Commission proposes the following amendments to the regulatory test to ensure consistency with the code:

Preamble

The Australian Competition and Consumer Commission promulgates this *regulatory test* in accordance with clause 5.6.5A of the National Electricity Code (the Code).

In this test, *augmentations, new large network assets* and *new small network assets* are called *proposed augmentations.*

The regulatory test

(1) The Commission has determined that the *regulatory test* is as follows:

A *proposed augmentation* satisfies this test if -

- (a) in the event the *proposed augmentation* is a *reliability augmentation*, it minimises the present value of the *costs*, compared with a number of *alternative projects*, in a majority of *reasonable scenarios*; or
- (b) in all other cases, the *proposed augmentation* maximises the present value of the *market benefit*, compared with a number of *alternative projects,* in a majority of *reasonable scenarios.*

4. Option 2: Definitional changes

4.1 Introduction

In its Discussion Paper, the Commission proposed a number of definitional amendments in an attempt to clarify elements of the regulatory test that may currently be considered ambiguous and open to interpretation. The Commission believes that to ensure a nationally consistent application of the regulatory test, terms used in the regulatory test should be defined as much as possible.

In defining the boundaries of the regulatory test, the Commission must maintain a balance between providing guidance on aspects of the regulatory test, and ensuring that the test is not too narrow and prescriptive resulting in the unintentional exclusion of real benefits or costs from the assessment which may have a material impact on the outcome of the regulatory test. Therefore, in addition to the proposed amendments outlined in Option 1, the Commission proposes to amend and define certain terms in the regulatory test which it considers will provide greater guidance, yet will provide sufficient flexibility for the regulatory test to evolve over time as it is applied by TNSPs.

The following section provides a summary of submissions in response to the Commission's Discussion Paper, and outlines the Commission's consideration of the amendments to the regulatory test reflecting comments made by interested parties in response to the Commission's proposed Option 2 amendments outlined in the Discussion Paper.

4.2 Summary of Submissions

CS Energy, Gallaugher, NEDF, ElectraNet, NRG Flinders, TransEnergie, VENCorp, TransEnd, and SPI PowerNet are generally supportive of the definitional amendments that the Commission puts forward in its Discussion Paper. Transend adds that detailed examples of how the regulatory test is to be applied in practice should be included in the notes on the methodology. While Gallaugher notes that in some cases the definitions put forward by the Commission do not go far enough to allay concerns with the way in which the regulatory test is currently being applied by TNSPs.

In contrast, Powerlink does not support including definitions in the regulatory test. It notes that the justification for increasing the prescriptiveness of the regulatory test has not been sufficiently demonstrated. Powerlink submits that greater definition may reduce the likelihood of conflicting interpretations and disputes, however 'micro-managing' how the regulatory test should be applied relies on the definitions being correct in every situation, or it will lead to unintended consequences and inefficient outcomes.

4.2.1 Alternative projects

Powerlink considers that the code provides sufficient guidance on the alternatives to be considered in a regulatory test assessment. However all other parties that made submissions agreed with the Commission's proposal to alter the definition of alternative project to provide greater guidance to NSPs in their application of the regulatory test.

Reliability augmentations

ElectraNet and Powerlink submit that the definition of an alternative project proposed in the Discussion Paper may cause problems in that it may lead to unintended difficulties in applying the regulatory test to reliability augmentations. They contend that it is not practicable to consider an alternative project for a reliability augmentation unless it has a clearly identifiable proponent who is prepared to enter into a network support agreement for the provision of the relevant services, given that reliability augmentations have a specific timeframe in which they must be completed to meet the relevant service standards. For this reason Powerlink adds that the phrase "operational within a similar timeframe" would not be appropriate for reliability augmentations.

Non-reliability augmentations

The NSW Ministry of Energy and Utilities considers that given TNSPs faces the risk of optimisation they should have the ability to select which regulated projects to put forward in a regulatory test assessment. However, should they not be compelled to be a proponent for an augmentation if they do not wish to be.

In contrast, TransEnergie argues that there is no requirement in the regulatory test or the code that an alternative project should have a committed, or even a likely proponent. Furthermore, TransEnergie argues that requiring an alternative network service to have a proponent is inconsistent with not requiring alternative generation and demand side projects to have proponents, and gives TNSPs power of veto over alternative projects. While TransEnergie agrees that the existence of a proponent is a shorthand way of showing that a project is both technically and commercially feasible, it suggests that the absence of a proponent should not imply that a project is not technically and commercially feasible.

The EUCV/ECCSA note that the listing by the Commission is appropriate, however they consider that the proponents for the proposed augmentation should identify and quantify what the outcomes of the augmentation are and whether the proposal itself has inherent alternatives. They contend that the experience of the Murraylink conversion process raises concerns about the adequacy of the NSP to provide comprehensive listings and analysis of alternative projects which should be evaluated for technical viability. They suggest that an independent body responsible for reviewing proposed augmentations (particularly interconnectors), such as the IRPC, should ensure that the proposal provides the optimum technical benefits to network users. They argue that this body could also ensure that all alternatives have been identified and their technical benefits and detriments clearly evaluated.

SPI Powernet, Gallaugher and the Hon Patrick Conlon are generally supportive of the proposed definition of an alternative project. However, they raise concerns with the proposal that for a proposal to be classified as a substitute, the outcomes delivered should be similar. Both argue that the term "similar" may be interpreted too broadly in some circumstances. SPI PowerNet notes that term could be used to refer to the extent to which the alternative project addresses the specific base needs or alternatively to the extent to which the quantified costs and possibly the value of benefits exhibit similarity.

Similarly, VENCorp suggests that any definition of 'substitute projects' should be framed in light of the need to ensure that such a definition would not provide a means of unduly limiting the consideration of feasible and potentially more cost-effective alternatives.

NRG Flinders notes that the approach recommended by the Commission offers greater clarity as to when an alternative should be recognised as valid, given the potential risks of gaming that the Commission has highlighted with respect to incumbent TNSPs. However, NRG Flinders notes that significant questions still remain over the ability to demonstrate that an alternative is technically feasible in the absence of any support from the relevant TNSP for the option. Similarly NRG Flinders notes that it remains an open question as to how it would be possible to establish that a project is commercially feasible if the TNSP denies its consent for that project.

While Energex considers that the regulatory test must involve a comparison of all alternative projects and should not be artificially limited as proposed by ElectraNet and the NSW Ministry of Energy and Utilities they do not support the inclusion of commercial feasibility as a criterion for assessing the practicability of the alternative project. Energex adds that removing the commercial feasibility criteria would avoid the potentially conflicted position of some planning entities, where a network support agreement can be withheld so as to ensure an alternative project is not considered commercially feasible and therefore not a practicable alternative project in the regulatory test.

TransEnergie considers that the proposed definition of practicable is not prescriptive enough to define and clarify these elements of the regulatory test in order to ensure a consistent and more rigorous application across the NEM. Gallaugher also states that the definitions of practicability are still to vague and open to gaming by TNSPs.

4.2.2 Market benefits and costs

ElectraNet, RNPP, Hydro Tasmania, TransEnergie, TransGrid, SPI PowerNet, Gallaugher, and VENCorp support the inclusion of a list of benefits and costs in the regulatory test as non-prescriptive examples. SPI Powernet, TransGrid and ElectraNet submit that the test should permit the proponent to incorporate additional benefits that may be identified over and above those that fall within the categories identified in guidelines if these can be demonstrated as providing real benefits in relation to specific augmentation proposals.

SPI PowerNet further suggests that the cost-benefit evaluation should be two tiered, the first incorporating the definition of benefits included within authorised guidelines, with provision for a second tier that would enable the proponent to include any additional benefits that may be identified. TransEnergie goes further and proposes that the Commission set down a methodology as to how individual benefits should be calculated.

Powerlink, EUAA and EAG do not consider the inclusion of examples of costs to be included in the regulatory test is warranted because it considers that the definition of costs in the regulatory test is comprehensive, particularly when read in conjunction with the notes in the regulatory test. Powerlink also submits that providing a list of benefits is unlikely to lessen the risk of dispute. It suggests that a better approach is for the evaluation of market benefits to converge through the setting of precedents. Further it notes that the code consultation process provides an opportunity for interested parties to point out any market benefits that they consider have not been appropriately evaluated.

Market benefits

Hydro Tasmania proposes that 'benefits of savings in fuel consumption', be made more general to incorporate the benefits that result from increased efficiency in the operation of hydro plant and other renewable generators. Hydro Tasmania suggests that it be redrafted to read:

> *benefits of savings from more efficient operation of generators*
> a. *differences in dispatch patterns*
> b. *differences in fuel costs*
> c. *differences in hydrological values and renewable operation*

AgForce, the National Farmer's Federation (NFF), Cambooya Shire Council, the Gold Coast City Council, Clifton Shire Council, and a number of Queensland residents note that the regulatory test should be broadened to also allow social benefits such as the undergrounding of transmission lines.

TransEnergie notes with respect to benefits in capacity deferrals, that it only be included in a manner that is consistent with the principle of competitive neutrality. TransEnergie notes that the Commission needs to ensure that the functions of the Reserve Trader role in the application of the regulatory test and the purpose of the level of VoLL are always complementary in nature. TransEnergie adds that the following procedures should be implemented in order to derive the appropriate level of generation capacity benefits for a proposed regulated investment:

- there needs to be a formal acknowledgement that market failure has occurred;
- the Reserve Trader should call for options to meet the identified need (this should include generation, demand side and market network service provider options);
- the cost of the generation, demand side and market network service provider options should be ranked against the cost of the proposed regulated network service; and
- contracts should be awarded to the options in order of increasing cost, until the identified shortfall has been met.

In regard to the deliverability of a capacity benefit, TransEnergie notes, with reference to VENCorp's application of the regulatory test to SNOVIC, that the deliverability of capacity benefits of a regulated network service needs to be tied down in order to ensure that it is competing on a level playing field with non-regulated options, and to ensure continued benefits to the consumers paying for the regulated network service. As a result, TransEnergie suggests that:

- in the short term, there is a need to perform sensitivity analysis to confirm the availability of sufficient surplus capacity in other regions; and
- in the longer term, the proponents of the regulated network service should be required to enter into contracts with interstate generation to confirm the deliverability of the promised capacity.

In regard to the deferral of reliability plant, NERA, in a consultancy for TransGrid, notes that different interpretations as to how to calculate the deferral of reliability plant may give materially different results. It suggests that it would be beneficial for the Commission to clarify whether it considers alternative approaches to be acceptable.

VENCorp submits that would be helpful if the list of market benefits distinguished between the cause and/or source of the benefit (eg change in dispatch patterns or reduced losses) and the mode of its measurement (ie reduced fuel costs). It further notes that the relevance of “total volume of VoLL generation forecast” is unclear, in terms of supply reliability. It considers that the only relevant consideration in an evaluation of net benefits is the expected level of involuntary supply interruption.

Gallaugher notes that the benefits of reduction in involuntary load shedding and the benefits of capital deferral or reliability entry plant are two different approaches to measuring the same benefit. Gallaugher argues that assuming the target reliability of supply of all competing options is to match the Reliability Panel’s published reliability standard, then one would expect there to be little or no comparative benefit between proposals in terms of reductions in involuntary load shedding.

Costs

NRG Flinders and Energex note that to ensure the integrity of the test it is necessary for the Commission to hold the proponent to account for the costs identified during the regulatory test in subsequently determining the regulatory value of an approved asset. NRG Flinders notes that this would place greater discipline on the costs identified during the course of the assessment

Gallaugher, Energex, TransEnergie, and VENCorp support the inclusion of the costs associated with equipment testing in the regulatory test evaluation. However VENCorp notes that the basis for estimating any such costs should be consistent with the principles underpinning the definition of net market benefits where only the net benefits are incorporated. Powerlink submits that this cost could be difficult to quantify for both local generation and transmission options, given the costs are spread between one or more TNSPs, NEMMCO and market participants. Powerlink and TransGrid note that the net cost to the NEM of testing may not be material given that wealth transfers are not incorporated into the test.

Gallaugher proposes adding the full range of market disruption costs associated with any new projects. Examples include market disruption costs associated with constriction, commissioning, operational testing, and ongoing maintenance.

4.2.3 Committed/anticipated projects

Committed project

VENCorp, Wamba Power Venture (WPV), RNPP, and TransEnergie support the proposed criteria for committed projects. WPV, RNPP, and TransEnergie note that it will provide consistency with NEMMCO’s criteria for committed projects used in the Statement of Opportunities (SOO). VENCorp further considers that the regulatory test should be clarified to ensure that all incremental costs of alternative options, such as avoidable costs, including committed projects are included in the evaluation.

ElectraNet and Powerlink agree that the NEMMCO criterion is a useful guide to be used for non-network alternatives. However, Powerlink and the Hon Patrick Conlon argue that the definition of committed projects is not relevant to a regulated network investment. They suggest that if a project satisfies the regulatory test it should be considered a committed project. In addition Powerlink adds that the Commission should be careful imposing links between the regulatory test and the acquisition of easements for a transmission line. While the Hon Patrick Conlon suggests that there may be merits in considering projects committed once they have passed the regulatory test if this approach was also supported by a non-refundable bond arrangement.

TransGrid's are similar. It submits that a more equitable application of the criteria for committed status should recognise the different processes that apply to a decision making process for the development of regulated and non-regulated assets. It proposes the following commitment criteria for both regulated and non-regulated assets:

> Committed criteria for both regulated and non-regulated projects:
>
> 1. the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement; and
> 2. construction of the proposal must either have commenced or a firm commencement date must be set.
>
> A regulated project would need to also meet the following additional criteria:
>
> 1. the proponent has demonstrated that the investment satisfies the regulatory test, in line with the provisions in the code.
>
> A non-regulated project would need to also meet the following additional criteria:
>
> 1. the proponent has purchase/settled/acquired land (or legal proceedings to acquire land) for construction of the proposed development;
> 2. contracts for supply and construction of the major components of the plant and equipment (such a generator, turbines, boilers, transmission towers, conductor, terminal station equipment) should be finalised and executed, including any provisions for cancellation payments; and
> 3. the financing arrangements for the proposal, including any debt plans, must have been conducted and contracts executed.

Gallaugher submits that there are essentially two key questions which should determine whether a project is likely to proceed:

- Are there still barriers to the project going ahead which are outside the control of the proponent, and what is the likelihood that these will cause its indefinite deferral or total abandonment? and
- What are the avoided costs of the project in the future (ie. ignoring irrecoverable sunk costs on the project to date) compared to its expected commercial benefits to the proponent if it goes ahead?

Gallaugher notes that NEMMCO's criterion attempts to capture this but it is possible in some cases that it will not. Gallaugher therefore suggest that if a proponent of an alternative project disagrees with the way its project has been classified in accordance with the proposed criteria, it should have the opportunity to make a case for a change in classification based on a verifiable statement of its position in relation to questions (a) and (b) above.

EUAA and EAG submit that the criterion proposed by the Commission in its discussion paper may be too stringent for demand-side response (DSR) proponents, unless sufficient lead time and sufficient information is available to allow DSR proposals to be developed.

NRG Flinders notes that the proposal to adopt the SOO committed criteria ensures consistency between the test and the IRPC planning processes. However, NRG Flinders notes that in some instances projects may be undertaken on balance sheet, the requirement for financing contracts to be signed may present barriers for such projects in demonstrating committed status. A letter of commitment from the governing body could perhaps be taken as sufficient evidence of commitment if all other criteria are met.

Anticipated project

Subject to the caveats raised with the definition of a committed project WPV, VENCorp, RNPP and TransEnergie concur with the Commission's proposed criterion for anticipated projects.

However, NRG Flinders submits the criterion outlined for anticipated projects may be difficult in practice to evidence the fact that actions are 'in process', and therefore additional clarifications and examples may therefore be required. A lack of clarity on this issue could result in legitimate anticipated projects being overlooked.

4.2.4 Discount rate

Transend, ElectraNet, RNPP, Powerlink, and VENCorp generally concur that the post-tax real cash-flow and the WACC is an appropriate approach in the application of the regulatory test. However, ElectraNet and Powerlink note that the regulatory test requires sensitivity testing to be conducted on the discount rate, which may make this conversion meaningless.

NERA is of the view that the appropriate discount rate is the WACC determined by the average risk profile of the market portfolio. It adds that that to adopt a different discount rate risks undermining the objective of competitive neutrality.

VENCorp concurs with the Commission that there should be a consistent treatment of regulated and unregulated options in the application of the regulatory test. VENCorp and the NEDF note that this principle should be achieved if the discount rate used is consistent with the opportunity cost of capital and that it would be reasonable to suggest that the regulatory determination of WACC for regulated TNSPs would provide a guide as to the opportunity cost of capital (for regulated electricity infrastructure). Further, they believe that it would be reasonable to suggest that the cost of capital of unregulated electricity infrastructure provides a guide to the opportunity cost of capital. VENCorp is of the view that these two WACCs provide reasonable estimates of the lower and upper limits of the discount rate that should be applied in the regulatory test.

In contrast Gallaugher is of the view that the use of the regulated WACC in the application of the regulatory test is not consistent with the aim of removing a potential source of bias between generation and transmission options. Gallaugher believes that the discount rate should be based on a higher beta value that is more in line with the perceived risk of this type of project to an entrepreneurial investor.

The NEDF argues that moving towards a cost of capital reflecting higher risk would result in an inappropriately short-term focus for investments, resulting in a move to the minimum sized, least capital cost solution. The NEDF adds that the pricing associated with regulated network investments reflects their economic life and would not be aligned with the investment process, and that this approach would be of particular concern if applied to regulated network investments designed to meet specified regulatory reliability standards.

VENCorp and the EUAA/EAGG agree with the Commission's proposal that the discount rate should be consistent with the definition of cash flows being discounted VENCorp is of the view that it would be appropriate to use a real pre-tax discount rate (WACC) and real pre-tax cash flow forecasts for the purpose of the regulatory test. VENCorp also notes that given the level of inflation and WACC that currently prevail, the choice of transformation method does not appear to have a material impact on the estimate of the discount rate.

4.2.5 VoLL

VENCorp, SPI Powernet, ElectraNet and Hydro Tasmania all strongly disagree with the Commission's proposal to use the VoLL wholesale market price cap as the basis to calculate the value of supply reliability to consumers under the regulatory test. VENCorp notes that it proposes to apply a Value of Customer Reliability (VCR) in its transmission investment evaluations derived from the results of customer surveys, the most recent of which suggested a VCR of $29,600/MWh in Victoria. It argues that this is appropriate because:

- this value is consistent with the VoLL around $26,500/MWh implied by the Reliability Panel's reliability standards for the wholesale electricity market; and
- the adoption of this approach is consistent with VENCorp's objectives, which requires its transmission augmentations to be aimed at maximising net benefits directly associated with the production and consumption of electricity industry participation (including end users) as a whole.

VENCorp notes that the Victoria Essential Services Commission (ESC) applied a VCR of around $28,000/MWh in the evaluation of the Somerton Power station. VENCorp therefore argues that the regulatory test should be amended to ensure that the calculation of economic benefits is based on the marginal value of supply reliability to consumers, rather than the VoLL wholesale market price cap.

Similar views are expressed by TransEnergie, ElectraNet and TransGrid. ElectraNet and SPI Powernet add that it is important to recognise that the VoLL as defined in the code is a wholesale market price cap and does not necessarily reflect the real or true value of the lost load to end use customers, which will vary by customer type and location. As a result ElectraNet supports the adoption of a realistic value of lost load based on customer research, including the adoption of different values at different locations, where this information is available. It argues that in the absence of location information, a composite value of at least $20,000/MWh would appear more appropriate than the wholesale market price cap specified in the code.

Hydro Tasmania notes that while there is some relation between the value of VoLL adopted in the code as a price cap to be applied to dispatch prices, it believes that there may well be customers for whom the value of lost load is greatly in excess of $10,000/MWh.
Hydro Tasmania believes that by adopting the energy market value in the application of the regulatory test, the regulatory test will be skewed against network investments for customers whose VoLL is higher than the market price cap, with the potential for inefficient outcomes.
Hydro Tasmania suggests that the VoLL figure generally be as specified in clause 3.9.4,

except where there is specific information that indicates that a higher figure is more appropriate.

Gallaugher contends that using a VoLL of $10,000/MWh maintains the competitive neutrality principle of the regulatory test. However, Gallaugher argues that the practical effect of this in the application of the regulatory test in its proposed form would be minimal because the bulk of regulated transmission investment would be justified on the basis of satisfying one form of standard or another, none of which are consistent with the application of a $10,000/MWh value of VoLL.

4.2.6 Disclosure requirements for reliability augmentations

VENCorp, Energex, NRG Flinders, RNPP, and TransEnergie generally support the additional disclosure requirements for reliability augmentations proposed by the Commission. VENCorp however notes that the proposed changes fall short of requiring net economic benefits of reliability driven augmentations to be demonstrated. While TransEnergie suggests further disclosure requirements should be included.

Alternatively, ElectraNet and Powerlink submit that the reliability limb of the regulatory test should remain in its current form, apart from the minor modifications to reflect changes in the code. ElectraNet, Powerlink, TransGrid and Transend therefore argue that the Commission's proposed disclosure requirements are an unnecessary duplication of existing code disclosure requirements.

4.3 Commission's Considerations

In relation to Option 2, the Commission notes the general support for redefining and clarifying some of the terms and expressions used in the regulatory test. The Commission considers that the most effective way to reduce confusion and ensure a consistent application of the regulatory test across the NEM is to define key terms in the regulatory test. However, in doing this the Commission has taken into account the view of the interested parties who disagree with making the test too prescriptive and therefore too narrow. The Commission considers that the following definitions improve NSPs and other parties' understanding of the regulatory test whilst also providing sufficient flexibility for the regulatory test to evolve over time.

4.3.1 Alternative projects

In considering the use of the term alternative projects, the Commission has taken into account the submissions made to it, the decisions of both the National Electricity Tribunal (NET) and the Supreme Court of Victoria in relation to SNI, and its experience gain through the Murraylink conversion process.

The Commission believes that the findings of the NET and the Supreme Court are relevant to how alternative projects should be identified for non-reliability augmentations. To this end, the Commission is of the view that for non-reliability augmentations, it is inappropriate to exclude a possible alternative project on the basis that is does not have an identifiable proponent.

While the Commission notes that the existence of a proponent is a good indicator of the feasibility, both technical and commercial, of a given project, it does not believe that it should not be a fundamental requirement that such a proponent be clearly identifiable. The Commission decision therefore reflects the fact that the existence of a proponent should be incorporated as an indicator of a projects practicability, but should not be a sole determinant.

Regarding the practicability of an alternative project, the Commission considers that this requirement is necessary. Defining what alternative projects are for the purposes of the Regulatory Test raised several concerns from those parties who lodged submissions. The Commission notes that in relation to the proposed definition included in the Discussion Paper the submissions addressed both the issue of technical feasibility and commercial feasibility.

Having noted the submissions in relation to technical feasibility, the Commission still considers this to be an appropriate indicator to use in determining alternative projects. It is appropriate for a TNSP to make a judgement on this when determining which alternative projects it wishes to use.

In relation to the use of the term "similar" the Commission considers that term may evolve over time through its use in the regulatory test. The Commission also believes that the same applies to the term "substitute". However, it notes that in its regulatory test assessment of Murraylink the Commission considered that an alternative project was a reasonable alternative if it delivered substantial gross market benefits to similar regions and or nodes.

Several submissions raised concerns that commercial feasibility was not a suitable criterion for the assessment of a project's practicability. It has been pointed out that an NSP is not in a position to make a determinative ruling on the commercial feasibility of a given project. However, the Commission considers that it is appropriate for an NSP to make their own judgement in relation to commercial feasibility when choosing which alternative projects to consider. Therefore, for the purposes of non-reliability augmentations more emphasis will be placed on the substitutability and practicability of alternative projects.

In relation to reliability augmentations, the Commission shares the concerns expressed by ElectraNet and Powerlink that the NET and the Supreme Court's findings are not applicable to how alternative projects should be identified for reliability augmentations. Statutory obligations imposed on TNSPs require network augmentations should be constructed within a specified timeframe. Therefore the Commission believes that greater emphasis is required on having an identifiable proponent. This ensures that the alternative project is capable of being completed by the required date due to reliability obligations and ensuring that the alternative project would meet those reliability obligations.

In response to comments made by TransGrid, the Commission has amended the regulatory test to clarify the distinction between references in the regulatory test to alternative options and those that refer to future developments that form part of market development scenarios. This will ensure that it is made clear for modelling purposes the requirements imposed on projects which are alternative options, and those projects which form part of market development scenarios.

As stated in its Discussion Paper, the Commission still remains of the view that it is not appropriate to strictly define the number of alternatives to consider when assessing a proposed augmentation under the regulatory test, as this will vary from case to case. The number of alternatives considered, however, should be proportional to the size and/or importance of the proposed augmentation.

<u>Proposed amendment to the regulatory test</u>

Taking into account comments provided by interested parties, the Commission proposes to amend the definition of alternative projects in the regulatory test as outlined below:

For the purposes of selecting an *alternative project* the following factors should be taken into account:

<u>Reliability Augmentations</u>

a) The *alternative project* should be a genuine alternative to the project being assessed, in particular it should:

   i) have a clearly identifiable proponent;
   ii) meet all necessary reliability obligations; and

b) The *alternative project* should be a practicable project. For the purposes of determining the practicability of the project the project must be technically feasible.

<u>Other augmentations</u>

a) The *alternative project* should be a genuine alternative to the project being assessed, meaning it should:

   i) deliver similar outcomes to those delivered by the project being assessed; and
   ii) become operational in a similar timeframe to the project being assessed.

b) The *alternative project* should be a practicable project. For the purposes of determine the practicability of the project the following will be taken into account:

   i) Technical Feasibility
   ii) Commercial Feasibility,
      a) Commercial feasibility will be demonstrated by determining whether an objective NSP in the position of a proponent acting rationally in the National Electricity Market would have a sufficient economic incentive to construct the *alternative project.*

Further, the existence of a genuine proponent for the *alternative project* will be taken into account when determining practicability; however absence of such a proponent will not exclude a project from being an *alternative project* for the purposes of the regulatory test.

4.3.2 Market benefits

The Commission notes that there was general support for the Commission's proposed list of benefits as a guide in the regulatory test. However, there were concerns raised by some interested parties that the proposed amendments did not go far enough and that the Commission should set down a methodology as to how the appropriate level of individual benefits are to be derived, while others submit that the Commission's proposed list of benefits does not add anything to the regulatory test.

The Commission still considers that there are advantages of including a non-exhaustive list of benefits into the regulatory test. It will be done in such as way so as not to preclude other valid benefits and costs from being included in the analysis where they are appropriate. At the same time it provides guidance on the range of benefits that can be considered in the evaluation of the proposed augmentation and its alternative projects under the regulatory test. The Commission notes that the inclusion or exclusion of each of the costs or benefits in the list, or other benefits or costs depends on the materiality of that cost or benefit to each option being considered. In addition, the Commission is of the view that the costs and benefits assessed in relation to a project need not be the same costs or benefits accruing to other options considered in a regulatory test assessment.

In listing possible methods for calculating benefits the Commission notes the preference of some parties it should also set out methodology for the derivation of those benefits. In particular there were calls for the Commission to define reliability benefits.

The Commission notes the different methods that can be used to calculate reliability benefits. NEMMCO in its SNI and SNOVIC assessments compared the reserve levels established by the Reliability Panel for each region in the NEM with the expected market generation under these reserve levels. Where NEMMCO identified a shortfall, it added reliability generation such that the reserve criteria would be met. VENCorp in its La Trobe to Melbourne assessment also adopted this approach. However, VENCorp assumed that its reliability plant was offered into the market at short run marginal cost for all market development scenarios except for long run marginal cost cases. In contrast, NEMMCO assumed the reliability plant is offered into the market at VoLL for all market development scenarios except for the least-cost planning scenario.

In its application for conversion, Murraylink assumed no reliability plant was commissioned. However Murraylink estimated reliability benefits as the change in un-served energy between the case which included Murraylink and that which did not. The annual reliability benefit was calculated as the change in estimated unserved energy multiplied by VoLL.

In its decision, the Commission considered that adopting NEMMCO's or VENCorp's approach, using the reliability entry plant methodology, and also accounting for benefits relating to deferral of merchant entry would result in a double counting of benefits. Therefore, the Commission's preference is for proponents to test the sensitivity of its reliability benefits to the varying methodologies.

More generally though, Commission believes that the decision on how market benefits should be calculated is best left to the market. The Commission considers that the code consultation process provides sufficient opportunity for other NSPs and interested parties to point out any market benefits that they consider have not been appropriately evaluated.

The Commission concurs with VENCorp's suggestion that the list of market benefits should distinguish between the cause and source of the benefits, and has adjusted the market benefits list accordingly. Furthermore, the Commission agrees with VENCorp that in term of supply reliability, the only relevant consideration in an evaluation of net benefits is the expected level of involuntary supply interruption, and the Commission therefore has removed 'total volume of VoLL generation forecast'.

The Commission notes the proposal of Queensland residents and Councils that the regulatory test should be broadened to incorporate social benefits and costs to the community from undergrounding transmission lines. The Commission recognises that undergrounding is one of the biggest issues facing transmission expansion in the NEM. The Commission is also aware of the difficulties and opposition being encountered by TNSPs in acquiring easements for new transmission lines. Undergrounding costs are required to be considered in a regulatory test assessment but the benefits are not.

The Commission continues to remain of the view that the calculation of benefits in a regulatory test assessment should only be limited to those who produce, distribute and consume electricity in the NEM. Further, the regulatory test makes it clear that only those costs and benefits that can be measured in terms of the financial transactions in the market should be included in the analysis. The Commission believes it is difficult to quantity in terms of financial transactions to the market the benefits of undergrounding transmission lines. Therefore, at this stage the Commission does not propose to allow the market benefits to include the benefits of undergrounding transmission lines. However, the Commission will continue to monitor this issue and may consider revisiting it in the future.

The Commission's list also explicitly incorporates competition benefits into the regulatory test. Competition benefits are discussed in detail in chapter 5.

Proposed amendment to the regulatory test

Taking into account comments provided by interested parties, the Commission proposes to amend the definition of market benefits in the regulatory test as outlined below:

In determining the *market benefits*, the analysis may include, but not limited to the following *market benefit:*

(1) In determining the market benefit, the analysis must include, but not be limited, to the following market benefits:

  (a) benefits of savings in fuel consumption caused through

    i. Differences in dispatch patterns

    ii. Differences in fuel costs

(b) benefits of reduction in voluntary load curtailment caused through

   i. reduction in demand-side curtailment

(c) benefits of reduction in involuntary load shedding caused through

   i. savings in reduction in loss of load

(d) benefits in capital deferrals caused through

   i. deferral of market entry plant or deferral of reliability entry plant

   ii. differences in capital costs

   iii. differences in the operational and maintenance costs

   iv. deferral of transmission investments

(e) benefits of reduction in transmission losses

(f) benefits of reductions in ancillary services

4.3.3 Costs

The Commission considers that consistent with its view with respect to market benefits, that a non-exhaustive list of costs should be incorporated into the regulatory test. The list does not preclude other valid costs from being included in the analysis where they are appropriate. However, it will provide guidance on the range of costs that should be considered in the evaluation of the proposed augmentation and its alternative projects under the regulatory test. Furthermore, as with market benefits, the Commission is of the view that the costs assessed in relation to a proposed augmentation need not be the same as those assessed for other alternative projects being considered in the regulatory test analysis.

The Commission notes that in contrast to the market benefit discussion there is limited discussion on which costs which should be included in the assessment of an augmentation under the regulatory test. The only concern was in relation to the inclusion of costs associated with equipment testing. The Commission considers that the inclusion of such costs should be consistent with the principles underpinning the definitions of net market benefits. That is, the wealth transfer aspect of that cost should not be incorporated into the regulatory test assessment. The Commission understands that these costs are spread between one or more TNSPs, NEMMCO and market participants and may be difficult to quantify. However, the Commission considers that the inclusion or exclusion of each of the costs in the list, or other costs depends on the materiality of those costs to each option being considered.

The Commission also notes comments made by NRG Flinders and Energex who suggest that the Commission should hold the proponent to account for the costs identified during the regulatory test assessment in subsequently determining the regulatory value of an approved asset. The role of the regulatory test in setting TNSP revenues is discussed in more detail in the Commission's capital expenditure framework paper.

<u>Proposed amendment to the regulatory test</u>

Taking into account comments provided by interested parties, the Commission proposes to amend the definition of costs in the regulatory test as outlined below:

Cost means the total cost of the *proposed augmentation* to all those who produce, distribute or consume electricity in the National Electricity Market. Any requirement in notes 1 to 9, inclusive, on the methodology to be used to calculate the *market benefit* of a proposed augmentation should also be read as a requirement on the methodology to be used to calculate the *cost* of an *proposed augmentation*. In determining the *cost* of the *proposed augmentation*, the analysis may include, but not limited to, the following *costs*:

(a) the capital costs incurred prior to commissioning;

(b) operating and maintenance costs over the operating life of the project;

(c) costs that arise from losses associated with power flow;

(d) ancillary service costs; and

(e) the cost of disruption to the National Electricity Market for testing of augmentations or upgrades, excluding wealth transfers associated with this cost.

4.3.4 Committed projects/anticipated projects

The Commission notes that the strength of a regulatory test assessment depends on how projects are classified. The regulatory test requires that the proponent identify committed and anticipated projects as part of the market modelling to ensure that the proposed augmentation and its alternatives are assessed with consideration to current and future project developments within or affecting the NEM.

Committed projects identified in a regulatory test assessment are considered in the 'base case' and are therefore incorporated in all market development scenarios. On the other hand, anticipated projects are considered in selected scenarios, but not necessarily all given there is less certainty surrounding whether such projects will proceed.

The regulatory test currently defines committed and anticipated projects with reference to the expected commissioning date of the project. The regulatory test states:

(a) projects, the implementation and construction of which have commenced and which have expected commissioning dates within three years (*committed projects*);

(b) projects, the planning for which is at an advanced stage and which have expected commissioning dates within 5 years (*anticipated projects*);

In its Discussion Paper, the Commission proposed an alternative definition based upon NEMMCO's committed project criteria used in the SOO. The Commission notes that the main issue of concern raised by interested parties in response to that proposal was that the

SOO criteria was a useful guide for non-network projects, but does not recognise that the regulatory test itself is the commitment process for regulated network options.

While the Commission sees that this may have some attractive features, the Commission believes that competitive neutrality would require that the hurdle for both regulated and unregulated projects be the same. Further a move towards NERA's proposed definition would require the Commission to define a regulated and non-regulated investment, which could make the test cumbersome.

The Commission also notes interested parties' suggestions that a project satisfying the regulatory test is by definition a *committed project*. The Commission considers that a proposed augmentation passing the regulatory test in itself does not constitute a *committed project*, given that issues such as planning consent approval, land acquisition, dispute resolution processes, are unlikely to have been finalised. There have been some projects which have satisfied the regulatory test, yet have not been constructed due to environmental considerations.

The Commission therefore remains of the view that the SOO criterion is appropriate for both regulated and non-regulated projects, and allows a consistent approach for both. NEMMCO's SOO also provides a consistency in the identification of *committed project* throughout the NEM and may assist in the identification of committed non-network options to be included in a regulatory test assessment.

The Commission agrees with NRG Flinders' concerns with the Commission's *anticipated project* criterion in that there may be difficulty in practice to identify which four criteria are 'in process'. However the Commission notes that while it may be difficult to show that all criteria are 'in process', that proponents should be able to show that at least one of the criterion is 'in process'.

The Commission therefore considers that the proposed criteria outlined below for anticipated and committed projects provide greater guidance and clarity on the projects to be classified into these categories.

<u>Proposed amendment to the regulatory test</u>

Taking into account comments provided by interested parties, the Commission proposes to amend the definition of committed projects in the regulatory test as outlined below:

A project is a *committed project* if it satisfies all the following criteria:

1. the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement;

2. construction of the proposal must either have commenced or a firm commencement date must be set;

3. the proponent has purchase/settled/acquired land (or legal proceedings to acquire

land) for construction of the proposed development;

4. contracts for supply and construction of the major components of the plant and equipment (such a generator, turbines, boilers, transmission towers, conductor, terminal station equipment) should be finalised and executed, including any provisions for cancellation payments; and

5. the financing arrangements for the proposal, including any debt plans, must have been conducted and contracts executed.

A project is an *anticipated project* if:

1. any one of the above criteria is not met; and

2. the project is in the process of meeting one or more of the above criteria

4.3.5 Discount rate

The Commission noted in its promulgation of the regulatory test in 1999, that the discount rate adopted for the purposes of a regulatory test evaluation should be a commercial discount rate in order to ensure that network and non-network investments are undertaken in a competitively neutral way. While stating that the discount rate should be a commercial discount rate, the regulatory test does not specify a method for estimating the discount rate.

The Commission notes that the discount rate has been a relatively uncontroversial parameter in the regulatory test assessments as it has been used to rank alternative projects under the regulatory test. To the extent that changes in the commercial discount rate do not change the ranking of options under the regulatory test, the Commission would expect that the choice of discount rate not be controversial.

Submissions received in response to the Discussion Paper generally supported the Commission's outlined methodology for the estimation of a discount rate with reference to a WACC. There was also support for a pre-tax discount rate given that market benefits and costs tend to be calculated with debt, interest payments and tax excluded. The main issue of concern raised was that the use of a regulated WACC in the application of the regulatory test is not consistent with the aim of removing a potential source of bias between generation and transmission options.

The Commission notes VENCorp's comments that the Commission's regulatory determinations of WACC provide a guide to the opportunity cost of capital for regulated electricity infrastructure. It also suggests that the cost of capital of unregulated electricity infrastructure provides a guide to the opportunity cost of capital for unregulated electricity infrastructure. The Commission considers that the two WACCs may provide the upper and lower limits of the discount rate that should be considered in a regulatory test application. The Commission also notes that the choice of parameters for unregulated electricity infrastructure and regulated infrastructure will vary and depend on the prevailing market conditions at the time of the regulatory test assessment.

Proposed amendment to the regulatory test

Taking into account comments provided by interested parties, the Commission proposes to amend the method for the calculation of the discount rate in the regulatory test as outlined below:

The net present value calculation should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector using the following formula:

$$W = r_e \frac{(1-T)}{(1-T(1-\gamma))}\frac{E}{V} + r_d(1-T)\frac{D}{V}$$

where:

r_e = required rate of return on equity, after company tax;

r_d = pre-tax weighted average cost of debt;

T = effective tax rate;

E = market value of equity;

D = market value of debt;

V = market value of debt plus equity; and

γ = value between 0 and 1 to reflect the fact that an investor may not benefit to the full value of imputation credit implied by the tax payment of the company.

In determining whether to use a real, nominal, pre or post tax discount rate, the guiding principle is that the discount rate used should be consistent with the cash flows being discounted.

4.3.6 VoLL

The Commission notes the general concern that the use of VoLL, which is primarily used as a wholesale price cap, may not always be an appropriate value for making a determination of the true value of lost load to customers. The Commission notes the decision by VENCorp to apply a VCR in its transmission investment valuations. Some submissions argue that using a VoLL of $10,000/MWh would be in accordance with both the code as well as principles of competitive neutrality. The Commission considers that it is necessary to balance the principles of competitive neutrality with the principles of market efficiency.

The Commission believes that the principle of market efficiency would suggest that the VCR should be used to represent the true value of supply reliability. In contrast, competitive neutrality would suggest that the VoLL wholesale price cap be used. In balancing these two principles, the Commission considers that both VoLL, at $10,000/MWh, and VCR, where it has been estimated, should be used in a regulatory test assessment. The Commission believes that both should be used in the sensitivity analysis anyway.

<u>Proposed amendment to the regulatory test</u>

Taking into account comments provided by interested parties, the Commission proposes to amend the use of the term VoLL in the regulatory test as outlined below:

2) In determining the *market benefit*, the following information should be considered;

   a) the cost of the proposed augmentation
   b) reasonable forecasts of:
      a. the value of energy to electricity consumers as reflected in either the level of VCR and/or VoLL;
      b. etc

4.3.7 Other issues

Market failure test

As noted in Option 1 of the Draft Decision, Powerlink raises concerns with note 7(c) of the regulatory test noting that the regulatory test requirement that new interconnectors must not be determined to satisfy this test if the start of construction is within 18 months of the project's need first being identified in a public report is biased towards non-regulated interconnectors.

The Commission in its December 1999 promulgation of the regulatory test included provisions for a 'market failure component' for inter-regional augmentations and new interconnectors. The Commission noted that the purpose of the 'market failure test' was to ensure that the construction of projects that would provide net benefits is not deferred.

The Commission believes that this provision has been misinterpreted by interested parties. It was not intended that interconnector construction can only proceed 18 months after the regulatory test was applied. Rather it was intended to ensure that the market is informed in advance of emerging network limitations. This can be either through a TNSP's annual planning report or NEMMCO's SOO. The Commission believes that TNSP's annual planning reports are providing much need information to the market.

The Commission believes that the code consultation process provides opportunities for non-network options to come forward. Furthermore the code requires that NSPs consider all reasonable network and non-network options. Clause 5.6.6(b)(iii) requires the proponent to consider:

> " all reasonable network and non-network alternatives, including but not limited to interconnectors, generation options, market network service options involving other transmission and distribution networks "

To avoid confusion the Commission proposes to remove note (7). The Commission also notes that the improvements in planning and information disclosure coming out of the Ministerial Council on Energy communiqué particularly the recommendation for a National Transmission Statement will provide opportunities for promoting investment opportunities from a national perspective.

Proposed amendment to the regulatory test

Taking into account comments provided by interested parties, the Commission proposes remove Note (7) from the regulatory test.

Disclosure requirements for reliability augmentations

In the Discussion Paper, the Commission proposed incorporating a disclosure requirement for reliability augmentations into the notes accompanying the regulatory test. The Commission, however, concurs with TransGrid, Transend, Powerlink, and ElectraNet that the proposed information requirements are an unnecessary duplication of existing code disclosure requirements. The Commission also notes that the proposed additional disclosure requirements proposed by TransEnergie are largely in line with the code's disclosure requirements.

Furthermore, the Commission notes the IRPC's work in developing guidance for assessing whether or not a proposed new small network asset or a new large network asset is a reliability augmentation (clause 5.6.3(1)). As part of that Issues Paper, the IRPC proposes providing additional information disclosure requirements with respect to reliability augmentations. The Commission believes it best to defer this issue to the IRPC's review.

The Commission notes concerns raised by VENCorp and Gallaugher with respect to limb (a) of the regulatory test (reliability augmentation). The Commission notes that the reliability limb of the regulatory test has the effect of bringing forward proposed augmentations to meet reliability obligations compared to the economic assessment under the market benefits limb. Ideally there should be no separate criteria for the assessment of reliability augmentations given that the market benefits limb is capable of capturing and valuing reliability benefits. However, the Commission notes that there are service standards in the code and jurisdictional legislation which imposes standards on NSPs which the Commission must consider in developing and amending the regulatory test.

The Commission concurs with Powerlink that the reasons for adopting a distinction between reliability and other augmentations in the Commission's regulatory test have not changed from 1999 when the regulatory test was developed. Limb (a) of the regulatory test allows network service providers to meet statutory designated reliability standards without unreasonable barriers. The code also requires that the Commission consider a NSP's reliability obligation in the context of the regulatory test.

Therefore, the Commission proposes to retain the existing reliability limb of the regulatory test as a 'minimisation of cost' assessment. The Commission agrees with SPI PowerNet that the reliability limb of the regulatory test may need to be retained until such time that there is sufficient confidence in the approach used in valuing all benefits, including the specific value of reliability.

The Commission however proposes to make a minor amendment by replacing the words 'net present value' with 'present value' to reduce confusion with respect to the requirements of the reliability limb of the regulatory test. That is, reliability augmentations should only consider the present value of costs. It does not include an assessment of market benefits.

Proposed amendment to the regulatory test

To reduce confusion with respect to the requirements of the reliability limb of the regulatory test, the Commission proposes to replace the words 'net present value' in the regulatory test with 'present value'.

Market development scenarios and sensitivity analysis

The expected net market benefits of options considered in a regulatory test assessment depend on the behaviour that is assumed for market participants. As the behaviour of market participants cannot be predicted with certainty and will depend on bidding strategies, market development scenarios need to be considered in a regulatory test assessment. Furthermore, due to the nature of modelling, the testing of key input parameters is important to ensure and demonstrate the robustness of the analysis.

The regulatory test requires that market development scenarios be considered under both the reliability limb and market benefits limb of the regulatory test. In addition, the regulatory test specifies that sensitivity analysis should be undertaken to test key input parameters, such as "including capital and operating costs, the discount rate and commissioning date, in order to demonstrate the robustness of the analysis" (note d). While the Commission considers that the regulatory test provides a guide to what market development scenarios must encompass, the Commission believes it would be appropriate to provide a guide on the type of sensitivity analysis that a proponent must consider in a regulatory test assessment covering both the reliability and market benefits limbs of the test.

The Commission has therefore provided a non-exhaustive list of input parameters which the sensitivity analysis should encompass where appropriate.

Proposed amendment to the regulatory test

Taking into account comments provided by interested parties, the Commission proposes to amend the definition of alternative projects in the regulatory test as outlined below:

Sensitivity testing must be conducted on where appropriate, but not be limited to, the following:

(a) Market benefits
  ii. Using all reasonable methodologies, including levels of customer reliability i.e VoLL and VCR

(b) Capital and operating costs of:
  ii. Alternative projects

iii. Committed projects
iv. Anticipated projects
v. Modelled projects

(c) Discount rate

(d) Market demand

(e) Generation bidding behaviour using
ii. SRMC
iii. Approximating realistic bidding

(f) Commissioning dates of:
ii. Alternative projects
iii. Committed projects
iv. Anticipated projects
v. Modelled projects

The sensitivity testing should always ensure that relevant reliability standards are met.

5. Option 3: Competition Benefits

5.1 Introduction

The third option discussed by the Commission in its discussion paper addressed the issue of "competition" benefits. The biggest criticism of the test by some market participants is that the current regulatory test does not recognise "competition benefits". In its Discussion Paper, the Commission submitted several options for the consideration of interested parties on how "competition benefits" may be incorporated into the regulatory test. These options were:

- Market simulations - which utilises the modelling currently required under the regulatory test
- Powerlink's Public Benefits Competition test – which utilises market modelling but is triggered in "Public Interest" situations
- Hirschmann-Hefindahl and modified Hirschmann-Hefindahl indices – which would aim to apply the tools used by competition authorities worldwide in assessing merger applications
- A residual supply analysis – using the techniques currently under consideration by the Californian ISO
- Commercial Benefits Analysis – utilising the Inter-Regional Settlements Residues and
- Stanwell Competition Index – which uses qualitative tools for the assessment of competition benefits

The responses received reflected the wide array of views on what "competition benefits" were and how they should be measured. As a result, the Commission conducted a forum to debate competition benefits, in particular, considering the following questions:

- What are competition benefits? and
- How should they be measured?

This section considers the views of interested parties in submissions to the Commission and at the market review forum. It includes a discussion by the Commission's consultant, Farrier-Swier, and concludes with the Commission's considerations.

5.2 Summary of Submissions

The submissions received in responses to the Discussion Paper outlined a wide range of views on how to define "competition" benefits. For example should "competition benefits" only deal with the "welfare triangle" or should it include wealth transfers. Further the submissions addressed the issues of how "competition benefits" should be calculated and whether or not they are currently in the regulatory test.

On the whole most parties who provided submissions to the Commission's Discussion Paper were in support of including "competition benefits". However, there were a number of submissions which argued that "competition benefits" should not be included in the regulatory test because of the potential errors that could occur and disputes that may arise.

5.2.1 Defining competition benefits

While there was strong support for the inclusion of "competition benefits" in the regulatory test, how those "competition benefits" are defined differed between the parties. VENCorp, the NSW Ministry of Energy, Gallaugher, TransGrid, ElectraNet, TXU, EME, SPI PowerNet and Origin support a definition of "competition" benefits which is limited to benefits from increases in market efficiencies.

Of these parties, TransGrid and TXU propose definitions of "competition benefits". TransGrid suggests that "competition benefits" could be those benefits which consider the change arising from bringing market prices being above marginal costs (due to … generation market power) closer to marginal costs as a consequence of a project (due to reduction of market power, i.e. "greater competition"). Similarly, TXU proposes that "competition benefits" are benefits from the increased economic surplus that occurs as a result of increased (satisfied) demand when prices return to marginal cost due following increased competition.

TransGrid and Drayton also suggest that "competition benefits" should capture the broader benefits of changes in consumption arising from lower electricity prices.

Despite supporting the concept of "competition benefits" SPI PowerNet states that it is not appropriate for TNSPs to assume the role of determining whether market power exists and propose measures to alleviate costs arising from market power. Meanwhile VENCorp believes that "competition" benefits should be addressed by the jurisdictions in a separate process from the regulatory test.

Gallaugher questions the Commission's legal authority in its role as economic regulator of the TNSPs to expand the test to include "competition benefits", and believes that it is incumbent on the Commission to demonstrate that it has the power to incorporate "discriminatory provisions" in the regulatory test in favour of regulated transmission investment.

Powerlink, Stanwell, the Hon Patrick Conlon, Bardak, the EUAA and EAG in a joint submission, and the EUCV/ECCSA in a joint submission support a broader definition of "competition benefits" which considers the benefits of lower prices to electricity consumers. Under this approach, Powerlink defines "competition benefit" as the benefits of lower pool prices from increased competition between generators in the wholesale electricity market that can result from a network augmentation. The EUAA/EAG, Bardak and the EUCV/ECCSA argue that because consumers are required to pay for most of the transmission charges only those investments which benefit consumers should be allowed to proceed.

In contrast the Australian Council for Infrastructure and Development, the Essential Services Commission of South Australia, TransEnergie, NRG Flinders and Origin argue that "competition" benefits should be excluded from the regulatory test as subjective nature of the modelling that is likely to be required will further delay transmission investment and increase the possibility of appeals.

5.2.2 Calculating competition benefits

Opinion was divided on how best to calculate "competition" benefits. Most submissions focused on market modelling, issues that would need to be addressed if it is adopted and the limitations of the approach. Some parties also commented on the alternative approaches raised by the Commission in its discussion paper.

Market modelling

Drayton, TransGrid, Stanwell, Bardak, Powerlink and Mr Winsen support the calculation of "competition" benefits using market modelling.

TransGrid adds that it supports the use of Nash Equilibrium modelling as one possible method, but would welcome other approaches if they reflect actual market behaviour. It argues that the Nash Equilibrium approach estimates increases in productive and allocative efficiencies (the static effects of the inclusion of net competition benefits) for a notional project.

Stanwell recommends that market simulations should only be adopted if the following principles are satisfied:

- All TNSPs or planners use at least two alternative modelling methodologies;
- A set of data for each model is agreed and accepted by industry stakeholders; and
- Long-run MC bidding is used in all cases as an underlying principle with economic opportunity bidding used when constraints bind.

Further, Stanwell notes that it may take considerable time to evaluate and select a model which meets these conditions and therefore recommends that in the short-run, while a model is developed, a benchmark approach to identifying the most beneficial transmission augmentation be included. It suggests that this could be done by establishing a benchmark qualifier for an augmentation, and the augmentation would proceed on a lowest cost option basis, with boundaries and limits set to avoid the risk of over investment.

Bardak argues that as the power industry has been dealing with the modelling of low probability and uncertain events for many years the modelling of the actual pool outcomes in the NEM is the most appropriate way to calculate "competition benefits".

Of those parties noted previously who argue that market modelling is inappropriate, Origin states that "competition" benefits remains impossible to reliably and accurately measure because it requires forecasting the future bidding behaviour of generators over some specified period of time as well as customers' responses to those prices. It submits that these variables are highly subjective and leave the regulatory test open to considerable dispute and regulatory delay. NRG Flinders notes along similar lines that it becomes increasingly reliant on forecast modelling inputs and assumptions into the future, introducing subjectivity and therefore scope for disputes into the regulatory test.

Powerlink's public benefits test

TransEnergie argues that the criteria proposed by Powerlink are highly subjective and are likely to lead to increased disputation on how to appropriately capture the associated "competition benefits". In considering market power issues, TransEnergie notes that in order to assume an augmentation will capture "competition benefits"; it will need to be clearly demonstrated on a case by case basis. TransEnergie also notes that the possession or acquisition of market power is an insufficient condition to constitute a breach of the relevant provisions of the *Trade Practices Act 1974* (TPA), and therefore questions whether it is appropriate to be used by a TNSP in the context suggested by Powerlink.

HHI

CS Energy states that of the methods presented it believes that the HHI index appears the most credible and robust. It adds, however, that there is no need to be limited to one methodology provided that quantifiable benefits can be derived from each one, "competition benefits" to be added to other market benefits, the method could be empirical or qualitative, and the methodology should be appropriate to both intra and inter-regional investment projects.

Energex shares the views of CS Energy in relation to the HHI approach. However, Energex notes that it has not had the opportunity to test the practicability of implementing these approaches.

Residual Supply Index

Ergon Energy supports further investigation of a Price Cost Marginal Index (Lerner Index), focusing on participant behaviour and measuring the difference between price and marginal cost.

IRSRs

Hydro Tasmania favours a simpler approach over one that offers more scope for dispute, even at some cost to economic rigour and therefore notes that the Commission's IRSRs approach has some appeal. It notes that that while this approach can only be applied inter-regionally, it may be possible to derive equivalent information for intra-regional investments. It suggests that this could be done by studying simple simulations of historic price outcomes with and without the proposed intra-regional investment.

General issues

The Hon Patrick Conlon and ElectraNet support having the "competition" test applied as a separate test, and suggests that the Commission consider commissioning research into what might constitute an objective and quantifiable competition test. ElectraNet adds that this limb should allow gross benefits.

The EUCV/ECCSA state that the Commission could calculate from any or all of the various options a quantification of the competition benefit, and from these develop a view of the probable "competition benefit". They also question how the results of the regulatory test and competition test might be combined if "competition" benefits are treated as a separate test.

Powerlink notes that disputes may occur in processes where there are winners and losers. However, Powerlink is of the view that legitimate disputes are part of a proper process to ensure that a case for transmission augmentation is robust.

5.2.3 Competition benefits in the regulatory test

TransGrid, TransEnd, ElectraNet and TXU argue that based on their definitions of competition benefits, the regulatory test currently allows these benefits to be calculated. Drayton Analytics adds that measures of benefits and costs under the existing regulatory test, by definition account for all relevant economic impacts from changes in production and consumption (due to a project).
To avoid uncertainty both TransGrid and Transend believe that competition benefits should be added to the additional list of benefits that the Commission proposed in the Discussion Paper.

Powerlink and VENCorp believe that "competition" benefits is not currently included in the regulatory test. Powerlink argues that the existing test does not allow the inclusion of net "competition benefits" associated with changes in the cost of supply (where this is above marginal cost) and the effects of resulting pool price changes on electricity consumption. VENCorp suggests that "competition benefits" are not contemplated in the current definition of the regulatory test and that the regulatory test should continue to be the primary economic evaluation tool applied by TNSPs.

5.3 Consultants report

In June 2003, the Commission engaged Farrier Swier Consulting (Farrier Swier) to consider the various options outlined in the discussion paper and to report on the issues arising from the practical implementation of the various approaches to the measurement of "competition benefits". Its report titled "An Analysis of Competition Benefits" was released in July 2003 and presented to the Market Review Forum, held in Melbourne on 28 July 2003[5].

5.3.1 Defining competition benefits

Farrier Swier defines "competition benefits" to be:

> benefits attributable to increased transmission capability of bringing NEM prices closer to Short Run Marginal Costs (SRMC)

and can be captured under the regulatory test's 'market-driven market development' approach (note 6) where non-SRMC bidding is assumed.

It states that "competition benefits" can be considered to consist of three main economic efficiency elements:

- Allocative efficiencies from increased production and sales if a transmission augmentation lowers prices;
- Allocative efficiencies from avoiding or deferring the construction of generation and transmission assets (which may otherwise be developed if prices were higher); and

---

5 Farrier Swier's report can be found at: www.accc.gov.au/content/index.phtml/itemId/344969/fromItemId/54368

- Productive efficiencies from lower priced generation plant replacing higher priced plant.

Farrier Swier notes that in addition to the economic efficiencies, lower prices can also redistribute wealth from generators in previously higher priced regions and consumers in lower priced regions to generators in lower priced regions and consumers in higher priced regions. However, it submits that the current calculation of market benefits within the regulatory test excludes such an interpretation.

5.3.2 Calculating competition benefits

Farrier Swier contends that the extent to which an augmentation will reduce market power depends on a number of factors. These may include the level of forward contracting or hedging, the degree of vertical integration of generation and supply, the industry structure, shape of the supply curve, capacity margins, elasticity of demand, transmission incentives, market design and definition of transmission capacity. It therefore concludes that the best approach to calculating "competition benefits" is by using market simulation modelling.

It provides examples of possible approaches to modelling the strategic behaviour of firms, which have been described by Borenstein et al (1999) and Newberry (2002), including:

- The Cournot-Nash approach which assumes that firms employ quantity strategies: each firm chooses its production quantity, taking as given the output being produced by all other firms;
- The Bertrand equilibrium in which firms compete on price and it is assumed that the winner-takes-all i.e. any firm can capture the entire market by pricing below others and can expand output to meet such demand; and
- The Supply Function Equilibrium in which the strategies of firms are actual price-quantity bid functions, rather than the inflexible quantity given by the Cournot model6.

Farrier-Swier argues that applying strategic modelling approaches to the calculation of market benefits allows the impact of market power changes attributable to a transmission augmentation to reflect the response of market participants to the changed environment.

On the other approaches put forward in the Commission's discussion paper, Farrier Swier states that these are not helpful in providing a way to calculate "competition benefits". In particular it notes:

- The Powerlink Public Benefits approach appears to impose a potentially significant analytical burden for no useful purpose;
- The HHI and adjusted HHI do not adequately describe the changes in prices and do not assist in quantifying "competition benefits";
- CAISO's work on building a relationship between prices and the residual supply is interesting but could quickly become bogged-down in the detail of the statistical analysis;

6 Bushnell et al, 1999. An international comparison of models for measuring market power in electricity, Energy Modelling Forum, Stanford University and Newbery D, 2002. Mitigating market power in electricity networks. Department of Applied Economics, University of Cambridge.

- The commercial benefits approach is at odds with the welfare economic basis of the regulatory test; and
- The various elements of the Stanwell Competition index are vaguely defined and as a result cannot be assessed.

5.4 Commission's Considerations

5.4.1 Defining competition benefits

Efficiency gains vs. wealth transfers

What is evident from the submissions is that interested parties largely fall into two camps. There are those who consider that "competition" benefits are benefits arising from an increase in the market's efficiency. The opposing view is that the calculation of "competition" benefits should be based on a broader social objective of reducing prices to electricity consumers. In economic terms, this view considers the transfer of wealth from producers to consumers as a benefit. In balancing these views the Commission has turned to its obligations under the code and, in particular, the objectives that it must consider in promulgating the regulatory test.

In promulgating the regulatory test the Commission must:

> (b) have regard to the need to ensure that the *regulatory test* is consistent with the basis of asset valuation determined by the *ACCC* for the purposes of clause 6.2.3; and

Clause 6.2.3 sets out the principles that are applicable to the regime under which the Commission regulates transmission revenues. Clause 6.2.3 provides that:

> …
>
> (d) The regulatory regime to be administered by the *ACCC* must be consistent with the objectives outlined in clause 6.2.2 and must also have regard to the need to:
>
> (1) provide *Transmission Network Owners* and/or *Transmission Network Service Providers* (as appropriate) with incentives and reasonable opportunities to increase efficiency;
>
> …

The objectives outlined in clause 6.2.2 are

> …
>
> (b) an incentive-based regulatory regime which:
>
> (1) provides an equitable allocation between *Transmission Network Users* and *Transmission Network Owners* and/or *Transmission Network Service Providers* (as appropriate) of efficiency gains reasonably expected by the *ACCC* to be achievable by the *Transmission Network Owners* and/or *Transmission Network Service Providers* (as appropriate); and
>
> (2) provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to *Transmission Network Owners* and/or *Transmission Network Service Providers* (as appropriate) on efficient investment,

given efficient operating and maintenance practices of the *Transmission Network Owners* and/or *Transmission Network Service Providers* (as appropriate);

(c) prevention of monopoly rent extraction by *Transmission Network Owners* and/or *Transmission Network Service Providers* (as appropriate);

(d) an environment which fosters an efficient level of investment within the *transmission* sector, and upstream and downstream of the *transmission* sector;

(e) an environment which fosters efficient operating and maintenance practices within the *transmission* sector;

(f) an environment which fosters efficient use of existing infrastructure;

…

The Commission believes that it is clear that clauses 6.2.2 and 6.2.3 of the code emphasise that the regime it administers must provide for the *efficient* operation, provision and expansion of transmission facilities. As a consequence of enhanced efficiencies, reductions in prices can and do arise. But lower prices are not an objective in itself. It is the Commission's view that if the writers of the code had intended that reducing prices for consumers were to be an objective it would have been expressly stated. It was likely that they considered that promoting efficiency would ensure the benefits for the market as a whole. That is the benefits will accrue to both producers and consumers of electricity, not just consumers.

The code's objectives of promoting economic efficiency were also paramount in the Commission's original promulgation of the regulatory Test in 1999. In its decision the Commission stated that:

> in developing the regulatory test the Commission has relied on the two key principles of ***economic efficiency*** (emphasis added) and competitive neutrality.[7]

Therefore, in keeping with the code's objectives the Commission considers that the calculation of "competition" benefits must be limited to considering those benefits arising from increases in efficiency from the augmentation of transmission networks.

The Commission notes that calculating "competition" benefits as increases in economic efficiency is the preferred approach of Professor Stephen Littlechild. In his presentation to the Market Review Forum, Professor Littlechild stated:

> A conventional view is that competition means price equal to marginal (or average) cost, in contrast to monopoly which means marginal revenue equal to marginal cost hence price above marginal cost (and above average cost). On this view, the competition benefits of a transmission investment are primarily the advantages of having lower prices (which reflect less market power) in the wholesale generation market.[8] Set aside the resulting transfer of income between generators (investors) and consumers, which is presumably not considered in a public benefits test. The benefit of competition is then presumably the greater output that is induced by the lower prices, valued at the difference between price and marginal cost. This is the so-called welfare triangle.[9]

---

7 ACCC; Regulatory test for New Interconnectors and Network Augmentations: 15 December 1999

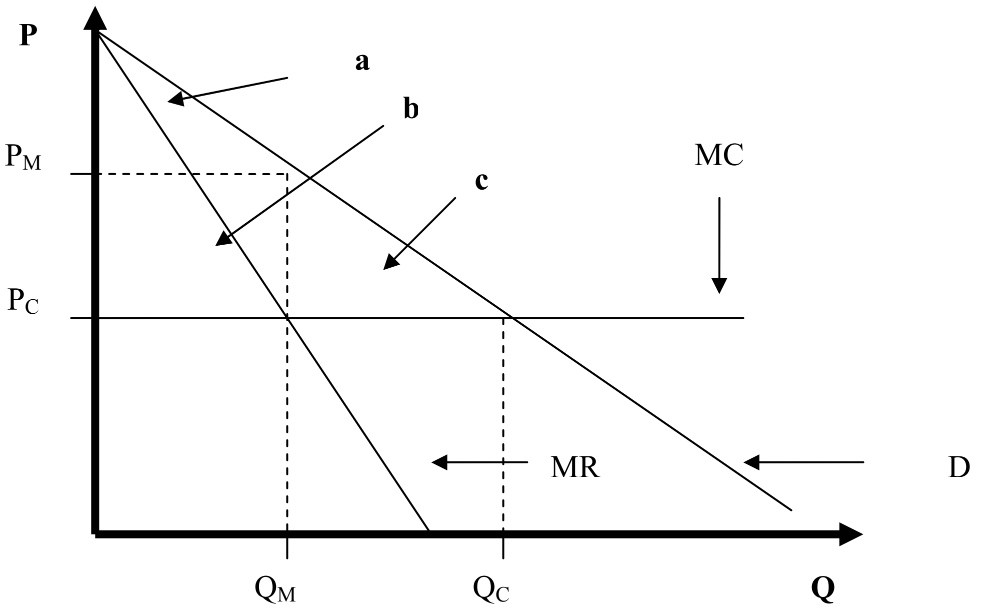
8 Cf. "Competition arises from increased competition between generators, and the reduction in market power, resulting from free flowing interconnectors." ACCC 2002, p. 38

9 This triangle in the higher priced region may of course be offset by another triangle of reduced output in the lower priced region.

Economic efficiency and wealth transfers: A simple model

To understand the differences between the transfer of income between generators and consumers, and increases in efficiency a simplified model of the market is outlined below. A diagram of this kind has been presented, in differing forms, in some of the submissions.

Diagram 1



Assume initially that the supply of electricity in a market is provided by a single generator, with a flat Marginal Cost (MC) curve. Assume in the first instance that the generator is able to exercise market power. It will set a price which maximises its profits by reference to the intersection of the Marginal Revenue (MR) and MC curves. The market clearing price and quantity for electricity will be given by P_M and Q_M respectively. In this case, the consumer surplus, being the area under the demand curve and above price, is given by the area **a**. While the producer surplus, being the area above the marginal cost curve but below price, is given by the area **b.** Area **c** is known as the dead weight loss. In this region, there are consumers willing to purchase electricity at a marginal value above the marginal cost, but are unwilling to do so at the price that the generator sets.

Assume now that the generator is forced to sets its price equal to marginal cost, which could result from potential entry or regulatory intervention. The result is a fall in the price of electricity from P_M to P_c and an increase in quantity supplied from Q_m to Q_c. The consumer surplus is now given by the area **a** + **b** + **c,** because there are more consumers who are purchasing electricity at the price charged by the generator**.** The producer surplus has gone from area **b** to zero.

The gains and losses in the market are relatively straight forward. Consumers gain from the decrease in price from P_M to P_C and an increase in quantity from Q_M to Q_c ,(area **b** + **c**). While the generator loses from the decrease in price and from P_M to P_C and Q_M to Q_C respectively (area **b**). From this it is easy to see that area **b** has been transferred from generators to consumers. The net increase in welfare, or increase in market efficiency, is given by the area **c**, the welfare triangle described by Professor Littlechild.

Some of the submissions recommended that the Commission effectively weight increases in consumer surplus higher than increases in producer surplus. However, the Commission does not believe that this is consistent with the objectives set out in the code.

"Competition" benefits and market efficiency

In confining the definition of "competition" benefits to only deal with increases in economic efficiency it is worth considering the elements of economic efficiency. There are three often quoted elements to economic efficiency: allocative efficiency, productive efficiency and dynamic efficiency. Allocative efficiency occurs when firms employ resources to produce goods and services that provide the maximum benefit to society. Productive efficiency occurs when firms have the appropriate incentives to produce services at least cost. Dynamic efficiency considers the longer term impact on the market and considers when firms have appropriate incentives to invest and innovate over time.

The benefits in regulatory test assessments to date have largely been confined to fuel costs savings and reliability requirements, and the deferral of generation and transmission investments. However, there are additional benefits which have not been measured. An augmentation to the transmission network is likely to affect how generators bid into the NEM. In particular, an augmentation to the transmission network is likely increase competition between existing generators, causing them to submit offers which are closer to short-run marginal cost. Previous regulatory test assessments have mostly been limited to consideration of short run marginal cost bidding.

The Commission believes that if a TNSP assumes non-competitive bidding there will be a significant change in the quantum and timing of the market benefits of an augmentation. Farrier-Swier argues that assuming non-competitive bidding will increase allocative efficiency, via increases in the production and sales of generation as well as from avoiding or deferring the construction of generation and transmission assets, and productive efficiency with the displacement of high price plant with lower price plant.

Professor Littlechild, in his presentation, also provides some insights as to what efficiencies arise from "competition" benefits:

> In electricity markets, the welfare triangle may be very small. Even where price is considerably above marginal or average cost, the demand elasticity is so low that reducing price may lead to a very small increase in demand. If there is not much increased output, the total value of such increased output is very low. This raises the question whether it is worth bothering to include competition benefits in the regulatory test.
>
> A possible argument is that the above calculation takes an unduly restrictive view of the nature and effects of competition. Surely more effective competition in generation should also force generators to seek efficiencies and reduce their generation costs more than they otherwise would? Surely it would allow retailers to compete more effectively too? They would be able to make more alternatives available than they otherwise would. This would result from their being able to buy directly through an interconnector, for example, but more generally as a result of generators now being keener to discover and meet the needs of their customers the retailers.

> In principle, these arguments apply not only in generation and supply, but also in transmission and distribution. That is, in assessing the competition benefits of any investment, it is necessary to ask what effect it would have on the efficiency and prices of the transmission and distribution networks. In particular, would a regulated investment reduce the scope for competition from non-regulated investment? If so would this reduce the pressure on incumbent transmission and distribution companies to increase their efficiency and respond to the needs of other market participants?
>
> In principle, all these arguments apply not only to prices and costs but also to quality and variety of service. They apply also to innovation. Generators and retailers (and transmission operators) do not compete merely by adjusting the prices and quality of existing goods and services; they also invent new ones.
>
> This leads into a broader view of competition as a rivalrous process of discovery and change. More effective competition means faster adaptation to change and faster discovery and testing of new ideas. Customers stand to benefit from all this, but in ways that cannot be fully anticipated today. Indeed, part of the value of competition is that it discovers things that are not yet known, and part of the aim of the participants in the competitive process is to take their rivals by surprise. Another value of competition is that it tends to identify those people and organisations that are good at discovering information, and to weed out those that are not.
>
> Personally, I am sympathetic to such a broad and dynamic view of competition, rather than a narrow view that looks only at prices and quantities in a rather static framework. The question I pose, however, is how far it is sensible to give a regulatory authority the responsibility to identify and quantify such a broad range of potential consequences of a transmission investment, in such a way as to add this into a regulatory benefit calculation. For some regulatory authorities this may be straightforward, for others not. (p 10)

While the Commission agrees that "competition" benefits will include the aforementioned benefits, such as bringing prices closer to marginal cost, more efficient dispatch of generation, and giving signals to innovate, it does not believe that this approach provides a workable definition of "competition" benefits. Therefore, the Commission proposes an alternative approach, which considers "competition" benefits using a framework not unlike how the NEM is dispatched (see Appendix D). As noted previously, an augmentation to a transmission network is likely to affect how generators bid into the market, and may see that generator submit bids which are closer to its actual marginal costs. While the generators bids are observable its marginal cost is not.

The Commission therefore believes that "competition" benefits can be defined by considering the effect of the augmentation on a generators bidding behaviour. In particular, the "competition" benefit will consider benefits arising from changes in bidding behaviour with and without the augmentations. That is the Commission believes that "competition" benefits can be defined as the change in the benefits arising from:

- the "augmented network" with bidding assumed to be the same as in the status quo network; and
- the "augmented network" with bidding which accurately and fully reflects any market power in the augmented network.

The Commission believes that this definition of "competition" benefits inherently captures the appropriate increases in efficiency from an augmentation by explicitly considering changes in a generators bidding strategy.

The Commission acknowledges that a more efficient electricity market may also increase the efficiency of downstream electricity users. Such a view is echoed in submissions and discussions at the Market Review Forum. However, at this stage, the Commission believes that the regulatory test should only consider those benefits and costs arising in the electricity market. To do otherwise would require the use of General Equilibrium modelling which the Commission believes would add a significant layer of complexity over and above what is currently required. The Commission will continue to monitor the viability of such an approach for the future.

Proposed amendment to the regulatory test

Taking into account comments provided by interested parties, the Commission proposes to define "competition" benefits in the regulatory test as outlined below:

The change in the benefits arising from the following two network scenarios:

- the "augmented network" with bidding assumed to be the same as in the status quo network; and
- the "augmented network" with bidding which accurately and fully reflects any market power in the augmented network.

5.4.2 Calculating competition benefits

In defining "competition" benefits as the market benefits arising from changes in generator bidding behaviour, the Commission must consider the strengths and weaknesses of the methodologies proposed during the course of its consultation to measure "competition" benefits. As noted previously, the options raised by the Commission in its discussion paper were:

- Powerlink's Public Benefits Competition test
- Hirschmann-Hefindahl and modified Hirschmann-Hefindahl indices
- A residual supply analysis
- Commercial Benefits Analysis
- Stanwell Competition Index
- Market simulations

Powerlink's Public Benefit's Competition test

Powerlink's proposal is to include a "third-limb" to the Regulatory Test which would take the form of a 2 step process. The steps it proposes are:

- Step 1 – identify a "trigger" which shows the potential for increased generator competition. The "trigger" could be either the observed instance(s) of price outcomes during network constraint events or one of the more straightforward indexes put forward in the discussion paper (eg- HHI). If this shows the potential for prices to be higher than marginal costs, proceed to Step 2
- Step 2 – identify the likely 'gross' customer benefits by either using the price data from observed events (arguably the most robust evidence of likely outcomes) and/or by carrying out forward-looking market modelling.

Regarding step 1, the Commission does not believe regulatory test should include a trigger to identify whether "competition" benefits are likely to arise. As noted by Drayton, such tests are typically based on historical information, which will not account for the change in behaviour of market participant. This point is also supported by Borenstein, Bushnell and Knittel[10] who note that the characteristics of the electricity industry: highly price-inelastic demand; significant short-run capacity constraints; and extremely costly storage, limits the usefulness of measures such as HHI. The Commission is of the view that it is entirely up to the TNSPs whether it decides to use a trigger as a catalyst to proceed with calculating "competition" benefits. The Commission will not mandate it.

On Powerlink's proposal to calculate "competition" benefits using current events the Commission's concern is that historical events are poor indicators of future events. However, the Commission supports Powerlink's proposal that "competition" benefits be calculated using market modelling providing that the market modelling only considers the net effect on the market, not the gross effect. Such an approach would ensure the calculation of "competition" benefits in a manner consistent with the Commission's definition. Using market simulations is discussed in more detail below.

Hirschmann-Hefindahl and modified Hirschmann-Hefindahl indices

The HHI index is a widely accepted measure of the concentration of an industry, and under assumed Cournot competition the change in the index is linearly related to changes in the price-cost mark-up multiplied by the elasticity of demand.

There was support for the use of the HHI and adjusted HHI as a tool to flag the existence of market power. However, as has been noted by a number of academic commentators, it has inherent weaknesses in being able to detect and forecast market power in the electricity market which is characterised by high storage costs and highly inelastic demand. Further it is unlikely that either of the HHIs would be able to be transformed into an analytical tool capable of quantifying the effect of market power.

The Commission agrees with Farrier-Swier's views that on the face of it using the HHI approach is an appealing prospect. This could be done by examining changes in the HHI before and after a transmission augmentation. But that there are a number of shortcomings with using such an approach the biggest of which is that it does not provide for an explicit calculation of "competition" benefits as defined by the Commission.

Even if the Commission could overcome this difficulty, as noted by Farrier Swier there are a number of further challenges in using the HHI as a measure. In particular:

- The calculation of the HHI is far from simple or necessarily robust: many competing producers have a portfolio of base, mid-merit and peaking plant. However competition takes place in the 5-minute markets through-out the day when different types of plant are at the margin. While a transmission augmentation may increase the number of firms competing with each other (an increase in the HHI), what really matters is the increase in competition in relevant 5-minute markets, for each region (there

10 Borenstein, S., Bushnell, J.B., and C. Knittel (1999)."Market Power in Electricity Markets : Beyond Concentration Measures," The Energy Journal, 20(4) 1999.

may be more than one if constraints are binding). This implies the calculation of HHI's in relevant settlement periods (or grouping of periods such as peak, off-peak). This leaves the problem of interpreting different HHIs in each settlement period and possibly in multiple regions if constraints are binding. Furthermore, the existence of forward contracts or hedges may affect changes in the way that units are bid into the market, irrespective of changes in the number of competitors.

- To translate changes in the HHI into changes in prices, the equality between changes in the HHI and changes in the Lerner Index multiplied by the elasticity of demand would be used. Therefore it is necessary to calculate Marginal Costs and the elasticity of demand. The calculation of marginal costs, as we described earlier is far from objective or straightforward. And, the elasticity of demand varies with the level of demand. The long term elasticity of demand in electricity markets remains poorly understood, and for the most part is not directly observable.
- As discussed earlier, while the assumption of Cournot competition may be a recognised method for modelling electricity markets, in the NEM, market participants simply do not know the production quantities of their competitors and the opportunity to re-bid almost to real time would seem to undermine the appropriateness of Cournot competition in NEM modelling.
- The definition of the markets affected by a transmission augmentation is problematic. It will depend on whether the proposed augmentation relieves constraints all or only some of the time, and different HHI measures would be calculated in each case. It also depends on the extent of constraints in other parts of the system. (pp 30-31)

As a result, the Commission does not support the use of HHI as a method to calculate "competition" benefits.

Residual Supply Index

The Residual Supply Index analysis estimates a relationship between observed price-cost mark-ups and certain market variables using the following formula:

$$L_{tr} = a + b(RSI_{t,r}) + c(TUC_{t,r}) + d(D_{t,r}) + e(SP_{t,r}) + f(NS_{t,r})$$

where:

L_{tr} Lerner Index for hour (t) in region (r)
RSI_{tr} Residual Supply Index in hour (t) and region (r)
TUC_{tr} total uncommitted capacity of the largest single supplier for hour (t) and region (r)
D_{tr} load in hour (t) and region (r)
SP_{tr} dummy variable for summer periods
NS_{tr} dummy variable for whether the zone is NP15 or SP15

It has been proposed by the CAISO as a method to calculate the benefits of reducing generator market power in California.

Its advantages are that it attempts to estimate a Lerner Index for each hour, for each region, for each year of the analysis. Such an approach would be similar to the market simulation methodology, and in fact utilises similar techniques. However, there are a number of shortcomings, which were noted by Drayton:

- It relies on historical relationships to predict future behaviour and therefore excludes generator responses to interconnection.
- It is not clear how the RSI would be calculated if an interconnector eliminates constraints between two regions: which pre-interconnection pricing region's estimated regression coefficients are used for calculating the price-cost margin?

- It is (unrealistically) assumed that all generating units (base load, mid-merit and peaking) mark-up price against marginal cost by the same percentage.
- To these we would add a general criticism of statistical regression approaches such as these to predict future behaviour. The starting point is usually an intuitively sensible relationship between variables. However it quickly becomes bogged-down in the detail of the statistical analysis. The CAISO experience suggests that the analysis also relies on a significant amount of data, much of which is not objectively verifiable. Unless the resulting statistic relationships are utterly compelling (and it would take many years to tell if they were anyway) such approaches are easy to discredit and may be unlikely to withstand logical, empirical scrutiny. (pp 28-29)

The Commission shares the views expressed by Drayton and therefore does not support the use of the RSI as a method for calculating "competition" benefits.

Commercial benefits analysis

The Commission proposed a methodology in the Discussion Paper which would calculate "competition" benefits by reference to the Inter-Regional Settlements Residues (IRSRs). The methodology proposed by the Commission was for a rolling average of the sum of the IRSRs between two regions with the rolling average being for either 12 or 24 months prior to an assessment of an interconnector against the regulatory test. While the Commission argued that the main attraction of this proposal was in its simplicity, it also noted that the approach had a number of shortcomings. Among its shortcomings were that it could only be used for the assessment of interconnectors, and that it was based on historic information. The Commission notes that, with the exception of TransEnd, there was no support from interested parties to use this method. Further, given the definition of "competition" benefits the Commission is of the view that this approach would give rise to the wealth transfers.

Therefore, the Commission does not support the use of the commercial benefits analysis as a method for calculating "competition" benefits.

Stanwell Competition index

The Stanwell competition index proposed developing a qualitative measure of "competition" benefits including:

- the number of consumers affected by the network limitation;
- the incremental electricity capacity supplied to the market following augmentation;
- the fuel mix of the incremental electrical capacity (indicating underlying cost structure); and
- the number of independent entities supplying the market following augmentation;

Similar to the HHI approach, the Stanwell's Competition index is unable to provide a quantifiable benefit. It would require the regulator or the TNSP to place a weighting on the likely effect of an augmentation on the market.

The Commission concurs with these views and for this reason does not propose to use it as a method to calculate "competition" benefits.

Market modelling

The Commission's preferred, and in its view the only practical, approach to calculating "competition" benefits, requires the use of market simulations. Market simulations were the preferred approach of most parties who supported defining "competition" benefits by reference to increases in economic efficiency in the market. The main strength of this approach is that it explicitly models generator bidding behaviour with and without an augmentation, which is consistent with the Commission's definition.

In supporting market simulations, the Commission recognises that that there are difficulties inherent in any modelling. Most notably, the assumptions that are made and the level of complexity will affect the outcome of the analysis. However, the Commission notes that under the current regulatory test assessments, TNSPs are required to model the effects of an augmentation on the bidding. In practice those, most parties have assumed SRMC bidding.

As has been noted in the submissions, there are a number of methodologies that can be used to simulate generator bidding in the market. Some of these methods were outlined in Farrier-Swier's paper, including:

- Cournot-Nash;
- Bertrand; and
- Supply Function Equilibrium

The Commission is not in a position at present to advocate one method of market modelling to calculate competition benefits over another. Over time, it is likely that TNSPS converge towards a particular model of imperfect competition. An example of a possible approach to market modelling was provided by Frontier Economics, in a consultancy for TransGrid. Frontier provided a worked one-year example of the application of Nash modelling to a 400MW interconnector between the Snowy and Victorian regions of the NEM.

In its example, Frontier Economics provides that the base case for analysing the augmentation by modelling the savings in cost with generators bidding at marginal cost. The next step is to work how prices would be affected by the augmentation, assuming particular generator portfolios, with the ability for the two largest portfolios either side of the interconnector to exercise market power by withdrawing capacity from the market. The benefit of the interconnector from the base case is thereby measured according to the increase (fall) in demand and the fall (increase) in price across the regions in the NEM. To aid the modelling contracts were assumed to be zero. Frontier Economics' results are replicated in tables 1 and 2 below.

Table 1

Annual price change due to upgrade			
Region	**Price without upgrade**	**Price with upgrade**	**Relative Change**
NSW	$23.24	$25.19	+8.4%
Qld	$15.76	$15.70	-0.4%
SA	$34.52	$32.65	-5.4%
Vic	$29.75	$27.02	-9.2%

Table 2

Average demand change due to price change			
Region	**Average demand without upgrade (MW)**	**Average demand without upgrade (MW)**	**Change (MW)**
NSW	8,434	8,349	-85
Qld	5,477	5,526	+49
SA	1,566	1,592	+26
Vic	5,597	5,755	+158

Its results show that the average annual price paid for electricity following the upgrade fell by over 9% in Victoria and over 5% in South Australia, remained largely unchanged in Queensland and increased by over 8% in NSW. When considering the effect of the change in price in the change in consumer demand, the result is "competition" benefits of $31 million.

Frontier Economics notes that is assumption about the level of demand response is arbitrary and that a robust estimation of competition benefits would include an estimate of the long run elasticity of demand. The Commission notes that NEMMCO in its SOO provides an estimate of the long run elasticity of demand which may prove useful in such an analysis.

The Commission believes that given Frontier Economics' estimated "competition" benefits is real and not insignificant, being over $30 million in just one year, the market simulation methodology is the most appropriate to use. Of course, the size of the benefit will depend on the generators that are considered and the length of time that the augmentation is modelled over. Examples of how "competition" benefits could be modelled are outlined in Appendices E and F.

The Commission is currently in the process of engaging a consultant to conduct an analysis of "competition" benefits using the market simulation modelling discussed. The Commission is also liaising with TNSPs who are currently involved in regulatory test assessments to consider the feasibility of working on live examples. The outcome of this report will be published and interested parties will be invited to comment on the outcome.

5.4.3 Competition benefits and the regulatory test

A number of submissions, particularly those which suggested that "competition" benefits be based on a broader social objective, raised the question as to whether "competition" benefits are currently included in the regulatory test. The Commission itself also noted in the Discussion Paper that the main criticism of the regulatory test is that it does not permit the calculation of "competition" benefits.

The Commission notes that at present, an application of the regulatory test essentially involves calculation of the net "market benefits" of a range of alternative projects, where:

> *market benefit* means the total net benefits of the *proposed augmentation* to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the increase in consumers' and producers' surplus or another measure that can be demonstrated to produce equivalent ranking of options in most (although not all) credible scenarios;

Therefore, for each project the market benefits is, in effect, the increase in benefits in a network scenario which includes the augmentation and a status quo network scenario. As such the regulatory test calculates benefits resulting from a transmission augmentation if and only if both:

- the total benefits under the status quo network scenario is calculated on the basis of the bids of generators which accurately and fully reflect any market power they have; and
- the total benefits under the augmented network scenario is calculated on the basis of the forecast and projected bids of generators which fully and accurately reflect any market power they may have under that new network.

The Commission notes that NEMMCO, in its assessment of SNI came to the view that "competition" benefits can be considered in a regulatory test assessment[11]. In particular it noted:

> The Regulatory Test requires the analysis of total "market benefit" which is defined as the total of the consumer and producer surpluses. To the extent that competition is increased by a project and this increase in competition creates a measurable increase in the market benefit, this should be considered in the assessment. Increased competition between regions provides benefits in reducing fuel costs by allowing cheaper remote generation to replace more expensive local generation. These fuel cost savings were taken into account in ROAM Consulting's modelling for the IRPC. (p 24)

This view is reiterated in a number of submissions.

Further, the Commission notes that the regulatory test explicitly requires that market simulations approximating actual market bidding be undertaken. In particular it note 6(b) states

> (b) The market-driven market development approach mimics market processes by modelling spot price trends based on existing generation and demand and includes new generation developed on the same basis as would a private developer (where the net present value of the spot price revenue exceeds the net present value of generation costs). The forecasts of spot price tends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate actual market bidding and prices, with power flows to be those most likely to occur under actual systems and market outcomes.

However, the Commission acknowledges that it may be possible that the requirement in note (6) which mentions "actual market bidding behaviour" is not sufficiently clear. In particular, it may not be clear that this should be interpreted to mean both bidding behaviour which accurately and fully reflects any market power under the status quo network and hypothetical, projected or forecast bidding behaviour which accurately and fully reflects any market power under the new augmented network. The Commission therefore proposes to modify the regulatory test to explicitly recognise imperfect bidding.

The Commission also proposes to amend the note referring to "actual market bidding behaviour" to recognise "imperfect competition" along the following lines

> The market-driven market development approach mimics market processes by modelling spot price trends based on existing generation and demand and includes new generation developed on the same basis as would a private

---

11 NEMMCO; Determination Under Clause 5.6.6 of the Code SNI Option, December 2001

developer (where the net present value of the spot price revenue exceeds the net present value of generation costs). The forecasts of spot price tends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate imperfect competition, with power flows to be those most likely to occur under actual systems and market outcomes.

Proposed amendment to the regulatory test

Taking into account comments provided by interested parties, the Commission proposes to clarify that "competition" benefits can be included in a regulatory test assessment and proposes to do so in the manner outlined below:

(6) In determining the *market* benefit the analysis may include *competition* benefits

Further, the calculation of "competition" benefits can only be achieved using market simulations of imperfect bidding behaviour

The market-driven market development approach mimics market processes by modelling spot price trends based on existing generation and demand and includes new generation developed on the same basis as would a private developer (where the net present value of the spot price revenue exceeds the net present value of generation costs). The forecasts of spot price tends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate imperfect competition, with power flows to be those most likely to occur under actual systems and market outcomes.

6. Conclusion

Taking into account submissions received from interested parties in response to its Discussion Paper, the Commission proposes a number of refinements to the regulatory test

The Commission proposes to incorporate all three suggested amendments. For comparative purposes, a copy of the current regulatory test is provided in Appendix B, and a copy of the revised regulatory test outlining the proposed amendments is provided in Appendix C, were a table outlining the changes is also included . The Commission invites interested parties to consider and comment on this Draft Decision. 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**.

Comments provided by interested parties will be incorporated into the Commission's Final Decision, where, if necessary, in accordance with clause 5.6.5A of the code, the Commission will promulgate changes to the regulatory test.

Comments provided by interested parties in response to this draft decision will be incorporated into the Commission's final decision, where if necessary, the Commission will promulgate changes to the regulatory test in accordance with clause 5.6.5A of the code.

Appendix A Submissions

The following submissions were received by the Commission in response to the Review of the Regulatory Test Discussion Paper:

1. Jim Gallaugher on behalf of TXU, LoyYang Power, Edison Mission Energy, Yallourn and International Power
2. AGL
3. Ergon Energy
4. Reliability and Network Planning Panel (Tasmania)
5. Electricity Supply Association of Australia Limited
6. Energy Retail Association of Australia
7. ENERGEX
8. Eraring Energy
9. NRG Flinders
10. CS Energy
11. Hydro Tasmania
12. Edison Mission Energy
13. Origin Energy
14. ElectraNet SA
15. Essential Services Commission of South Australia
16. Headberry Partners on behalf of The Electricity Consumer Coalition of South Australia, and The Energy Users Coalition of Victoria
17. Energy Users Coalition of Victoria & Electricity Consumer Coalition of SA
18. Ministry of Energy and Utilities (NSW Government)
19. Hon. Patrick Conlon MP (Minister for Energy, SA Government)
20. TransGrid
21. NERA on behalf of TransGrid
22. Frontier Economics on behalf of TransGrid

23. TransEnergie Australia
24. TXU
25. SPI PowerNet
26. VENCorp
27. Wambo Power Ventures Pty Ltd
28. Powerlink
29. Transend
30. Stanwell Corporation Ltd
31. National Electricity Distributors Forum
32. Cambooya Shire Council
33. Gold Coast City Council
34. Clifton Shire Council
35. Australian Council for Infrastructure Development Limited
36. AgForce
37. NFF Economic Committee
38. Tanah Merah Action Group
39. Power to the People Action Group
40. Power Down Under
41. R & BA&JR Piper
42. P Garlick & Associates Pty Ltd
43. J K Winson
44. H & J Gilmour
45. J McFadzean
46. DJ &DS Chandler
47. GS & MJ Hinz
48. WG & AM Lack
49. M & G Benson

50. Bardak Energy and Management Services

51. Dr Harrison

52. Energy Action Group & Energy Users' Association of Australia

Appendix B The Regulatory Test

Preamble

The Australian Competition and Consumer Commission promulgates this regulatory test in accordance with clause 5.6.5(q)(1) of the National Electricity Code (the Code).

The regulatory test is to be applied:

(a) to *transmission system* or *distribution system* augmentation proposals in accordance with clause 5.6.2 of the Code (*augmentation*);

(b) by NEMMCO and the Inter-regional Planning Committee to augmentation options identified under clause 5.6.5 of the Code other than applications for new interconnectors in accordance with clause 5.6.6 of the Code (*augmentation option*); and

(c) by NEMMCO and the Inter-regional Planning Committee to applications for new interconnectors across regions in accordance with clause 5.6.5 and 5.6.6 of the Code (*new interconnectors*).

In this test, *augmentations, augmentation options* and *new interconnectors* are called *proposed augmentations*.

The regulatory test

The Commission has determined that the regulatory test is as follows:
A *new interconnector or an augmentation option* satisfies this test if it maximises the *net present value* of the *market benefit* having regard to a number of alternative projects, timings and market development scenarios; and

An *augmentation* satisfies this test if –

(a) in the event the *augmentation* is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code – the *augmentation* minimises the net present value of the *cost* of meeting those standards; or
(b) in all other cases – the augmentation maximises the net present value of the *market benefit*

having regard to a number of alternative projects, timings and market development scenarios.

For the purposes of the test:

(a) *market benefit* means the total net benefits of the *proposed augmentation* to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the increase in consumers' and producers' surplus or another measure that can be demonstrated to produce equivalent ranking of options in most (although not all) credible scenarios;

(b) *cost* means the total cost of the *augmentation* to all those who produce, distribute or consume electricity in the National Electricity Market. Any requirements in notes 1 to 9, inclusive, on the methodology to be used to calculate the *market benefit* of a *proposed augmentation* should also be read as a requirement on the methodology to be used to calculate the *cost* of an *augmentation*;

(c) the net present value calculations should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector;

(d) the calculation of the *market benefit* or *cost* should encompass sensitivity analysis with respect to the key input variables, including capital and operating costs, the discount rate and the *commissioning* date, in order to demonstrate the robustness of the analysis;

(e) a *proposed augmentation* maximises the *market benefit* if it achieves a greater *market benefit* in most (although not all) credible scenarios; and

(f) an *augmentation* minimises the *cost* if it achieves a lower *cost* in most (although not all) credible scenarios.

Notes on the methodology to be used in the regulatory test to a proposed augmentation

(2) In determining the *market benefit*, the following information should be considered:

(a) the cost of the *proposed augmentation*;

(b) reasonable forecasts of:

i. electricity demand (modified where appropriate to take into account demand side options, variations in economic growth, variations in weather patterns and reasonable assumptions regarding price elasticity);
ii. the value of energy to electricity consumers as reflected in the level of VoLL;
iii. the efficient operating costs of competitively supplying energy to meet forecast demand from existing, *committed, anticipated and modelled projects* including demand side and generation projects;
iv. the capital costs of *committed*, *anticipated* and *modelled projects* including demand side and generation projects and whether the capital costs are completely or partially avoided or deferred;
v. the cost of providing sufficient ancillary services to meet the forecast demand; and
vi. the capital and operating costs of other regulated network and market network service provider projects that are augmentations consistent with the forecast demand and generation scenarios.

(c) the proponent's nominated *construction timetable* must include a *start of construction*, *construction time* and *commissioning*, where:

v. *start of construction* means the date at which construction is required to commence in order to meet the *commissioning* date, taking into consideration the *construction time* nominated by the proponent;

vi. *construction time* is the time nominated by the proponent to order equipment and build the project and does not include the time required to obtain environmental, regulatory or planning approval; and

vii. *commissioning* means the date, nominated by the proponent, on which the project is to be placed into commercial operation.

(2) In determining the *market benefit,* it should be considered whether the *proposed augmentation* will enable:

(a) a *Transmission Network Service Provider* to provide both *prescribed* and other services; or

(b) a Distribution Network Service Provider to provide both *prescribed distribution services* and other services

If it does, the costs and benefits associated with the other services should be disregarded. The allocation of costs between *prescribed* and other services must be consistent with the *Transmission Ring-Fencing Guidelines*. The allocation of costs between *prescribed distribution services* and other services must be consistent with the relevant *Distribution Ring-Fencing Guidelines*.

(3) The costs identified in determining the *market benefit* should include the cost of complying with existing and anticipated laws, regulations and administrative determinations such as those dealing with health and safety, land management and environment pollution and the abatement of pollution. An environmental tax should be treated as part of a project's cost. An environmental subsidy should be treated as part of a project's benefits or as a negative cost. Any other costs should be disregarded.

(4) In determining the *market benefit,* any benefit or cost which cannot be measured as a benefit or cost to producers, distributors and consumers of electricity in terms of financial transactions in the market should be disregarded. The allocation of costs and benefits between the electricity and other markets must be based on principles consistent with the *Transmission Ring-Fencing Guidelines* and/or *Distribution Ring-Fencing Guidelines* (as appropriate). Only direct costs and benefits (associated with a partial equilibrium analysis) should be included and any additional indirect costs or benefits (associated with a general equilibrium analysis) should be excluded from the assessment.

(5) In determining the *market benefit,* the analysis should include modelling a range of reasonable alternative market development scenarios, incorporating varying levels of demand growth at relevant load centres (reflecting demand side options), alternative project *commissioning* dates and various potential generator investments and realistic operating regimes. These scenarios may include alternative *construction timetables* as nominated by the proponent. These scenarios should include projects undertaken to ensure that relevant reliability standards are met.

These market development scenarios should include:

(a) projects, the implementation and construction of which have commenced and which have expected commissioning dates within three years (*committed projects*);
(b) projects, the planning for which is at an advanced stage and which have expected commissioning dates within 5 years (*anticipated projects*);
(c) generic generation and other investments (based on projected fuel and technology availability) which are likely to be commissioned in response to growing demand or as substitutes for existing generation plant (*modelled projects*); and
(d) any other projects identified during the consultation process.

(6) Modelled projects should be developed within market development scenarios using two approaches: 'least-cost market development' and 'market-driven market development'.

(a) The least-cost market development approach includes modelled projects based on a least-cost planning approach akin to conventional central planning. The proposals to be included would be those where the net present value of benefits, such as fuel substitution and reliability increases, exceeds the costs.

(b) The market-driven market development approach mimics market processes by modelling spot price trends based on existing generation and demand and includes new generation developed on the same basis as would a private developer (where the net present value of the spot price revenue exceeds the net present value of generation costs). The forecasts of spot price tends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate actual market bidding and prices, with power flows to be those most likely to occur under actual systems and market outcomes.

(7) In determining the *market benefit,* the *proposed augmentation* should not pre-empt nor distort potential unregulated developments including network, generation and demand side developments. To this end:

(a) a *proposed augmentation* must not be determined to satisfy this test more than 12 months before the *start of construction* date;

(b) a *proposed augmentation* will cease to satisfy this test if it has not commenced operation by 12 months after the *commissioning* date unless there has been a delay clearly due to unforeseen circumstances;

(c) unless there are exceptional circumstances, *new interconnectors* must not be determined to satisfy this test if *start of construction* is within 18 months of the project's need being first identified in a network's annual planning review or NEMMCO's statement of opportunities (or in some similar published document in the period prior to 13 December 1998).

(8) The consultation process for determining whether a *proposed augmentation* satisfies this test must be an open process, with interested parties having an opportunity to

provide input and understand how the benefits have been measured and how the decision has been made. Specific consultation is required on:

(a) identifying *committed projects* and *anticipated projects*;

(b) setting input assumptions such as fuel costs and load growth;

(c) modelling market behaviour and considering whether the market development scenarios are realistic;

(d) the proponent's *construction timetable*;

(e) understanding how benefits will be allocated; and

(f) understanding how a decision has been made.

(9) Any information which may have a material impact on the determination of *market benefit* and which comes to light at any time before the final decision must be considered and made available to interested parties.

Appendix C Proposed Regulatory Test

Preamble

The Australian Competition and Consumer Commission promulgates this *regulatory test* in accordance with clause 5.6.5A of the National Electricity Code (the Code).

In this test, *augmentations, new large network assets* and *new small network assets* are called *proposed augmentations.*

The regulatory test

(1) The Commission has determined that the *regulatory test* is as follows:

A *proposed augmentation* satisfies this test if -

(a) in the event the *proposed augmentation* is a *reliability augmentation*, it minimises the present value of the *costs*, compared with a number of *alternative projects*, in a majority of *reasonable scenarios*; or

(b) in all other cases, the *proposed augmentation* maximises the present value of the *market benefit*, compared with a number of *alternative projects,* in a majority of *reasonable scenarios.*

Notes on the methodology to be used in the regulatory test to a proposed augmentation

(2) In performing analysis under the *regulatory test*, the following sections should be applied:

(a) for the purposes of section 1(a), sections (3), (4) and (7) – (15) inclusive should be applied.

(b) for the purposes of section 1(b), sections (3) – (15) inclusive should be applied.

(3) In determining what is a *reasonable scenario* forecasts of the following should be considered:

vii. electricity demand (modified where appropriate to take into account demand side options, variations in economic growth, variations in weather patterns and reasonable assumptions regarding price elasticity);

viii. the value of energy to electricity consumers as reflected in the level of VCR and/or VoLL;

ix. the efficient operating costs of competitively supplying energy to meet forecast demand from existing, *committed, anticipated and modelled* projects including demand side and generation projects;

x. the capital costs of *committed*, *anticipated* and *modelled* projects including demand side and generation projects and whether the capital costs are completely or partially avoided or deferred;

xi. the cost of providing sufficient ancillary services to meet the forecast demand; and

xii. the capital and operating costs of other regulated network and market network service provider projects that are augmentations consistent with the forecast demand and generation scenarios.

(4) For the purposes of selecting an *alternative project* the following factors should be taken into account:

Reliability Augmentations

(a) The *alternative project* should be a genuine alternative to the project being assessed, in particular it should:

(i). have a clearly identifiable proponent; and

(ii). meet all necessary reliability obligations.

(b) The *alternative project* should be a practicable project. For the purposes of determining the practicability of the project the project must be technically feasible.

Other Augmentations

(c) The *alternative project* should be a genuine alternative to the project being assessed, meaning it should:

(i). deliver similar outcomes to those delivered by the project being assessed; and

(ii). become operational in a similar timeframe to the project being assessed.

(d) The *alternative project* should be a practicable project. For the purposes of determining the practicability of the project the following will be taken into account:

(i). Technical Feasibility

(ii). Commercial Feasibility

(a) Commercial feasibility will be demonstrated by determining whether a market participant acting rationally in the National Electricity Market would have a sufficient economic incentive to construct the *alternative project.*

Further, the existence of a genuine proponent for the *alternative project* will be taken into account when determining practicability; however absence of such a proponent will not exclude a project from being an *alternative project* for the purposes of the Regulatory Test.

(5) *Market benefit* means the total net benefits of the *proposed augmentation* (or an *alternative* project, when used for comparison) to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the net increase in consumers' and producers' surplus or another measure that can be demonstrated to produce an equivalent ranking of options in a majority of *reasonable scenarios*.

In determining the *market benefits*, the analysis may include, but need not be limited to the following benefits:

(a) benefits of savings in fuel consumption caused through

(i) Differences in dispatch patterns

(ii) Differences in fuel costs

(b) benefits of reduction in voluntary load curtailment caused through reduction in demand-side curtailment

(c) benefits of reduction in involuntary load shedding caused through savings in reduction in loss of load

(d) benefits in capital deferrals caused through

(i) deferral of market entry plant or deferral of reliability entry plant

(ii) differences in capital costs

(iii) differences in the operational and maintenance costs

(iv) deferral of transmission investments

(e) benefits of reduction in transmission losses

(f) benefits of reductions in ancillary services

(6) In determining the *market* benefit the analysis may include *competition* benefits

Competition benefits are defined to be the change in benefits arising from the following two network scenarios:

(a) the "augmented network" with bidding assumed to be the same as in the status quo network; and

(b) the "augmented network" with bidding which accurately and fully reflects any market power in the augmented network.

(7) In determining the *cost* or *market benefit*, any benefit or cost which cannot be measured as a benefit or cost to producers, distributors and consumers of electricity in terms of financial transactions in the market should be disregarded. The allocation of costs and benefits between the electricity and other markets must be based on

principles consistent with the Transmission Ring-Fencing Guidelines and/or Distribution Ring-Fencing Guidelines (as appropriate). Only direct costs and benefits (associated with a partial equilibrium analysis) should be included and any additional indirect costs or benefits (associated with a general equilibrium analysis) should be excluded from the assessment.

(8) In determining the *cost* or *market benefit*, it should be considered whether the *proposed augmentation* will enable:

(a) a Transmission Network Service Provider to provide both prescribed and other services; or

(b) a Distribution Network Service Provider to provide both prescribed distribution services and other services

If it does, the costs and benefits associated with the other services (including replacement works) should be disregarded. The allocation of costs between prescribed and other services must be consistent with the Transmission Ring-Fencing Guidelines. The allocation of costs between prescribed distribution services and other services must be consistent with the relevant Distribution Ring-Fencing Guidelines.

Any relevant information which may have a material impact on the determination of market benefit and which comes to light at any time before the final decision must be considered and made available to interested parties.

(9) *Cost* means the total cost of the *proposed augmentation* (or an *alternative project* when used for comparisons) to all those who produce, distribute or consume electricity in the National Electricity Market.

In determining the *cost* of the *proposed augmentation*, the analysis may include, but need not be limited to, the following *costs*:

(a) the capital costs incurred prior to commissioning;

(b) operating and maintenance costs over the operating life of the project;

(c) costs that arise from losses associated with power flow;

(d) ancillary service costs;

(e) the cost of disruption to the National Electricity Market for testing of augmentations or upgrades; and

(f) The *costs* identified in determining the *market benefit* should include the cost of complying with existing and anticipated laws, regulations and administrative determinations such as those dealing with health and safety, land management and environment pollution and the abatement of pollution. An environmental tax should be treated as part of a project's cost. An environmental subsidy should be treated as part of a project's benefits or as a negative cost.

The *costs* assessed in relation to a *proposed augmentation* need not be the same as those assessed for other *alternative projects* being considered in the regulatory test analysis.

(10) The present value calculations should use a *discount rate* appropriate for the analysis of a private enterprise investment in the electricity sector using the following formula:

$$W = r_e \frac{(1-T)}{(1-T(1-\gamma))}\frac{E}{V} + r_d(1-T)\frac{D}{V}$$

where:

r_e = required rate of return on equity, after company tax;

r_d = pre-tax weighted average cost of debt;

T = effective tax rate;

E = market value of equity;

D = market value of debt;

V = market value of debt plus equity; and

γ = value between 0 and 1 to reflect the fact that an investor may not benefit to the full value of imputation credit implied by the tax payment of the company.

In determining whether to use a real, nominal or pre or post tax discount rate, the guiding principle is that the discount rate used should be consistent with the cash flows being discounted.

(11) The analysis must include modelling a range of reasonable market development scenarios, incorporating varying levels of demand growth at relevant load centres (reflecting demand side options), alternative project commissioning dates and various potential generator investments and realistic operating regimes. These scenarios may include alternative construction timetables as nominated by the proponent providing that relevant reliability standards would be met.

Market development scenarios must include:

(a) *committed projects*;

(b) *anticipated projects*;

(c) *modelled projects*; and

(d) any other projects identified during the consultation process.

(12) A project is a *committed project* if it satisfies all the following criteria:

a. the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement; and

b. construction of the proposal must either have commenced or a firm commencement date must be set.

c. the proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for construction of the proposed development;

d. contracts for supply and construction of the major components of the plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) should be finalised and executed, including any provisions for cancellation payments; and

e. the financing arrangements for the proposal, including any debt plans, must have been conducted and contracts executed.

A project is an *anticipated project* if:

f. any one of the above criteria is not met; and

g. the project is in the process of meeting one or more of the above criteria

(13) *Modelled projects* could be developed within market development scenarios using two approaches: 'least-cost market development' and 'market-driven market development'.

(a) The least-cost market development approach includes modelled projects based on a least-cost planning approach akin to conventional central planning. The proposals to be included would be those where the net present value of benefits, such as fuel substitution and reliability increases, exceeds the costs.

(b) The market-driven market development approach mimics market processes by modelling spot price trends based on existing generation and demand and includes new generation developed on the same basis as would a private developer (where the net present value of the spot price revenue exceeds the net present value of generation costs). The forecasts of spot price tends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate actual market bidding and prices, with power flows to be those most likely to occur under actual systems and market outcomes.

(14) The calculation of the *market benefit* or *cost* should encompass sensitivity analysis with respect to key input variables. Appropriate sensitivity testing must be conducted on, but not be limited to, the following:

(g) Market benefits

   i. Using all reasonable methodologies, including levels of customer reliability i.e. VoLL, VCR.

(h) Capital and operating costs of;

   i. *Alternative projects*

   ii. *Committed projects*

   iii. *Anticipated projects*

   iv. *Modelled projects*

(i) Discount rate

(j) Market demand

(k) Generation bidding behaviour using

   i. SRMC

   ii. Approximating realistic bidding

(l) Commissioning dates of:

   i. *Alternative projects*

   ii. *Committed projects*

   iii. *Anticipated projects*

   iv. *Modelled projects*

The sensitivity testing should always ensure that relevant reliability standards are met.

(15) The proponent's nominated construction timetable must include a start of construction, construction time and commissioning, where:

   (i) start of construction means the date at which construction is required to commence in order to meet the commissioning date, taking into consideration the construction time nominated by the proponent;

   (ii) construction time is the time nominated by the proponent to order equipment and build the project and does not include the time required to obtain environmental, regulatory or planning approval; and

   (iii) commissioning means the date, nominated by the proponent, on which the project is to be placed into commercial operation.

(16) This version of the regulatory test applies to:

(a) a new small network asset that is the subject of consultation in a report published under cl 5.6.6A(a); and

(b) a new large network asset that is the subject of an application notice under cl 5.6.6(a);

after the date of promulgation.

All applications commenced prior to the promulgation of this version of the regulatory test are to be determined in line with the previous version of the regulatory test.

Proposed amendments	**Change from Previous version**
Preamble	**Preamble**
The Australian Competition and Consumer Commission promulgates this *regulatory test* in accordance with clause 5.6.5A of the National Electricity Code (the Code).	Amended "clause 5.6.5(q)(1)"
	to "clause 5.6.5A"
In this test, *augmentations, new large network assets* and *new small network assets* are called *proposed augmentations.*	
	Removed wording:
	"The regulatory test is to be applied:
	(d) to *transmission system* or *distribution system* augmentation proposals in accordance with clause 5.6.2 of the Code (*augmentation*);
	(e) by NEMMCO and the Inter-regional Planning Committee to augmentation options identified under clause 5.6.5 of the Code other than applications for new interconnectors in accordance with clause 5.6.6 of the Code (*augmentation option*); and
	(f) by NEMMCO and the Inter-regional Planning Committee to applications

	for new interconnectors across regions in accordance with clause 5.6.5 and 5.6.6 of the Code (*new interconnectors*)." Amended "In this test, *augmentations, augmentation options* and *new interconnectors* are called *proposed augmentations*." to "In this test, *augmentations, new large network assets* and *new small network assets* are called *proposed augmentations"*
Regulatory Test (1) The Commission has determined that the *regulatory test* is as follows: A *proposed augmentation* satisfies this test if - (a) in the event the *proposed augmentation* is a *reliability augmentation*, it minimises the present value of the *costs*, compared with a number of *alternative projects*, in a majority of *reasonable scenarios*; or (b) in all other cases, the *proposed augmentation* maximises the present value of the *market benefit*, compared with a number of *alternative projects,* in a majority of *reasonable scenarios.*	**Regulatory Test** Removed wording: The Commission has determined that the regulatory test is as follows: A *new interconnector or an augmentation option* satisfies this test if it maximises the *net present value* of the *market benefit* having regard to a number of alternative projects, timings and market development scenarios; and An *augmentation* satisfies this test if - (c) in the event the *augmentation* is proposed in order to meet an objectively

	measurable service standard linked to the technical requirements of schedule 5.1 of the Code – the *augmentation* minimises the net present value of the *cost* of meeting those standards; or (d) in all other cases – the augmentation maximises the net present value of the *market benefit* having regard to a number of alternative projects, timings and market development scenarios.
Notes on the methodology to be used in the regulatory test to a proposed augmentation (2) In performing analysis under the *regulatory test*, the following sections should be applied: (a) for the purposes of section 1(a), sections (3), (4) and (7) – (15) inclusive should be applied. (b) for the purposes of section 1(b), sections (3) – (15) inclusive should be applied.	Not in previous version of regulatory test
(3) In determining what is a *reasonable scenario* forecasts of the following should be considered:	Amended: "*market benefits"*

i. electricity demand (modified where appropriate to take into account demand side options, variations in economic growth, variations in weather patterns and reasonable assumptions regarding price elasticity); ii. the value of energy to electricity consumers as reflected in the level of VCR and/or VoLL; iii. the efficient operating costs of competitively supplying energy to meet forecast demand from existing, *committed, anticipated and modelled* projects including demand side and generation projects; iv. the capital costs of *committed, anticipated and modelled* projects including demand side and generation projects and whether the capital costs are completely or partially avoided or deferred; v. the cost of providing sufficient ancillary services to meet the forecast demand; and vi. the capital and operating costs of other regulated network and market network service provider projects that are augmentations consistent with the forecast demand and generation scenarios.	to "*reasonable scenarios*". Removed: "(a) the cost of the *proposed augmentation*" Amended numbering. Amended: "the value of energy to electricity consumers as reflected in the level of VoLL; to: "the value of energy to electricity consumers as reflected in the level of VCR and/or VoLL;"
(4) For the purposes of selecting an *alternative project* the following factors should be taken into account: *Reliability Augmentations* (a) The *alternative project* should be a genuine alternative to the project being assessed, in particular it should: (i). have a clearly identifiable proponent; and	Not in previous version

(ii). meet all necessary reliability obligations.

(b) The *alternative project* should be a practicable project. For the purposes of determine the practicability of the project the project must be technically feasible.

<u>Other Augmentations</u>

(c) The *alternative project* should be a genuine alternative to the project being assessed, meaning it should:

(i). deliver similar outcomes to those delivered by the project being assessed; and

(ii). become operational in a similar timeframe to the project being assessed.

(d) The *alternative project* should be a practicable project. For the purposes of determining the practicability of the project the following will be taken into account:

(i). Technical Feasibility

(ii). Commercial Feasibility

(a) Commercial feasibility will be demonstrated by determining whether a market participant acting rationally in the National Electricity Market would have a sufficient economic incentive to construct the *alternative project.*

Further, the existence of a genuine proponent for the *alternative project* will be taken into account when determining practicability; however absence of such a proponent will not exclude a project from being an *alternative project* for the purposes of the Regulatory Test.	
(5) *Market benefit* means the total net benefits of the *proposed augmentation* (or an *alternative* project, when used for comparison) to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the net increase in consumers' and producers' surplus or another measure that can be demonstrated to produce equivalent ranking of options in a majority of *reasonable scenarios*. In determining the *market benefits*, the analysis may include, but need not be limited to the following benefits: (a) benefits of savings in fuel consumption caused through (i) Differences in dispatch patterns (ii) Differences in fuel costs (b) benefits of reduction in voluntary load curtailment caused through reduction in demand-side curtailment (c) benefits of reduction in involuntary load shedding caused through savings in reduction in loss of load (d) benefits in capital deferrals caused through (i) deferral of market entry plant or deferral of reliability	Inserted: "(or an *alternative project*, when used for comparison)" Amended: "in most (although not all) credible scenarios" To: "in a majority of *reasonable scenarios*" Inserted: "In determining the *market benefits*, the analysis may include, but not limited to the following benefits: (a) benefits of savings in fuel consumption caused through (i) Differences in dispatch patterns (ii) Differences in fuel costs (b) benefits of reduction in voluntary load curtailment caused through

entry plant (ii) differences in capital costs (iii) differences in the operational and maintenance costs (iv) deferral of transmission investments (e) benefits of reduction in transmission losses (f) benefits of reductions in ancillary services	(i) reduction in demand-side curtailment (c) benefits of reduction in involuntary load shedding caused through (i) savings in reduction in loss of load (d) benefits in capital deferrals caused through (i) deferral of market entry plant or deferral of reliability entry plant (ii) differences in capital costs (iii) differences in the operational and maintenance costs deferral of transmission investments (e) benefits of reduction in transmission losses (f) benefits of reductions in ancillary services
(6) In determining the *market* benefit the analysis may include competition benefits. *Competition* benefits are defined to be the difference arising between the following two network scenarios: (a) the "augmented network" with bidding assumed to be the same as in the status quo network.; and (b) the "augmented network" with bidding which accurately and fully reflects any market power in the augmented network.	Not in previous version

(7) In determining the *costs* or *market benefit*, any benefit or cost which cannot be measured as a benefit or cost to producers, distributors and consumers of electricity in terms of financial transactions in the market should be disregarded. The allocation of costs and benefits between the electricity and other markets must be based on principles consistent with the Transmission Ring-Fencing Guidelines and/or Distribution Ring-Fencing Guidelines (as appropriate). Only direct costs and benefits (associated with a partial equilibrium analysis) should be included and any additional indirect costs or benefits (associated with a general equilibrium analysis) should be excluded from the assessment.	No changes from previous version
(8) In determining the *costs* or *market benefit*, it should be considered whether the *proposed augmentation* will enable: (c) a Transmission Network Service Provider to provide both prescribed and other services; or (d) a Distribution Network Service Provider to provide both prescribed distribution services and other services If it does, the costs and benefits associated with the other services (including replacement works) should be disregarded. The allocation of costs between prescribed and other services must be consistent with the Transmission Ring-Fencing Guidelines. The allocation of costs between prescribed distribution services and other services must be consistent with the relevant Distribution Ring-Fencing Guidelines. Any relevant information which may have a material impact on the determination of market benefit and which comes to light at any time before the final decision must be considered and made available to	No changes from previous version

interested parties.	
(9) *Cost* means the total cost of the *proposed augmentation* (or an *alternative project* when used for comparisons) to all those who produce, distribute or consume electricity in the National Electricity Market. In determining the *cost* of the *proposed augmentation*, the analysis may include, but need not be limited to, the following *costs*: (a) the capital costs incurred prior to commissioning; (b) operating and maintenance costs over the operating life of the project; (c) costs that arise from losses associated with power flow; (d) ancillary service costs; and (e) the cost of disruption to the National Electricity Market for testing of augmentations or upgrades. (f) The *costs* identified in determining the *market benefit* should include the cost of complying with existing and anticipated laws, regulations and administrative determinations such as those dealing with health and safety, land management and environment pollution and the abatement of pollution. An environmental tax should be treated as part of a project's cost. An environmental subsidy should be treated as part of a project's benefits or as a negative cost.	Inserted: "(or an *alternative project* when used for comparisons)" Deleted: "Any requirements in notes 1 to 9, inclusive, on the methodology to be used to calculate the *market benefit* of a *proposed augmentation* should also be read as a requirement on the methodology to be used to calculate the *cost* of an *augmentation*;" Inserted: "In determining the *cost* of the *proposed augmentation*, the analysis may include, but not limited to, the following *costs*: (a) the capital costs incurred prior to commissioning; (b) operating and maintenance costs over the operating life of the project;

The *costs* assessed in relation to a *proposed augmentation* need not be the same as those assessed for other *alternative projects* being considered in the regulatory test analysis.	(c) costs that arise from losses associated with power flow; (d) ancillary service costs; and (e) the cost of disruption to the National Electricity Market for testing of augmentations or upgrades. The *costs* assessed in relation to a *proposed augmentation* need not be the same as those assessed for other *alternative projects* being considered in the regulatory test analysis.
(10) The present value calculations should use a *discount rate* appropriate for the analysis of a private enterprise investment in the electricity sector using the following formula: $W = r_e \frac{(1-T)}{(1-T(1-\gamma))}\frac{E}{V} + r_d(1-T)\frac{D}{V}$ where: r_e = required rate of return on equity, after company tax; r_d = pre-tax weighted average cost of debt; T = effective tax rate;	Amended: "the net present value calculations should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector;" to: "The present value calculations should use a *discount rate* appropriate for the analysis of a private enterprise investment in the electricity sector using the following formula:

E = market value of equity; D = market value of debt; V = market value of debt plus equity; and γ = value between 0 and 1 to reflect the fact that an investor may not benefit to the full value of imputation credit implied by the tax payment of the company. In determining whether to use a real, nominal or pre or post tax discount rate, the guiding principle is that the discount rate used should be consistent with the cash flows being discounted.	$W = r_e \frac{(1-T)}{(1-T(1-\gamma))} \frac{E}{V} + r_d (1-T) \frac{D}{V}$ where: r_e = required rate of return on equity, after company tax; r_d = pre-tax weighted average cost of debt; T = effective tax rate; E = market value of equity; D = market value of debt; V = market value of debt plus equity; and γ = value between 0 and 1 to reflect the fact that an investor may not benefit to the full value of imputation credit implied by the tax payment of the company. In determining whether to use a real, nominal or pre or post tax discount rate, the guiding principle is that the discount rate used should be consistent with the cash flows being discounted.
(11) The analysis must include modelling a range of reasonable market development scenarios, incorporating varying levels of demand growth at relevant load centres (reflecting demand side options), alternative project commissioning dates and various potential generator investments and realistic operating regimes. These scenarios may include alternative construction timetables as nominated by the proponent providing that	Deleted: "In determining the *market benefit*"

relevant reliability standards would be met. Market development scenarios must include: (a) *committed projects*; (b) *anticipated projects*; (c) *modelled projects*; and (d) any other projects identified during the consultation process.	Amended: "These market development scenarios should include: (a) projects, the implementation and construction of which have commenced and which have expected commissioning dates within three years (committed projects); (b) projects, the planning for which is at an advanced stage and which have expected commissioning dates within 5 years (anticipated projects); (c) generic generation and other investments (based on projected fuel and technology availability) which are likely to be commissioned in response to growing demand or as substitutes for existing generation plant (modelled projects); and (d) any other projects identified during the consultation process." To: "Market development scenarios must include: (a) committed projects; (b) anticipated projects; (c) modelled projects; and (d) any other projects identified during the consultation process.

(12) A project is a *committed project* if: (a) the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement; and (b) construction of the proposal must either have commenced or a firm commencement date must be set; and (c) the proponent has purchased/settled/acquired land (or legal proceedings to acquire land) for construction of the proposed development; and (d) contracts for supply and construction of the major components of the plant and equipment (such a generator, turbines, boilers, transmission towers, conductor, terminal station equipment) should be finalised and executed, including any provisions for cancellation payments; and (e) the financing arrangements for the proposal, including any debt plans, must have been conducted and contracts executed. A project is an *anticipated project* if: (f) Any one of the above criteria is not met; and (g) The project is in the process of meeting one or more of the above criteria.	Not in previous version
(13) *Modelled* projects could be developed within market development scenarios using two approaches: 'least-cost market development' and 'market-driven market development'.	No changes from previous version

(a) The least-cost market development approach includes modelled projects based on a least-cost planning approach akin to conventional central planning. The proposals to be included would be those where the net present value of benefits, such as fuel substitution and reliability increases, exceeds the costs. (b) The market-driven market development approach mimics market processes by modelling spot price trends based on existing generation and demand and includes new generation developed on the same basis as would a private developer (where the net present value of the spot price revenue exceeds the net present value of generation costs). The forecasts of spot price tends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate actual market bidding and prices, with power flows to be those most likely to occur under actual systems and market outcomes.	
(14) The calculation of the *market benefit* or *cost* should encompass sensitivity analysis with respect to key input variables. Appropriate sensitivity testing must be conducted on, but not be limited to, the following: (a) Market benefits i. Using all reasonable methodologies, including levels of customer reliability i.e. VoLL, VCR. (b) Capital and operating costs of; i. *Alternative projects* ii. *Committed projects*	Deleted: ", including capital and operating costs, the discount rate and the *commissioning* date, in order to demonstrate the robustness of the analysis" Inserted: "Where appropriate sensitivity testing must be conducted on, but not be limited to, the following: (a) Market benefits (i). Using all reasonable methodologies, including levels

iii. *Anticipated projects* iv. *Modelled projects* (c) Discount rate (d) Market demand (e) Generation bidding behaviour using i. SRMC ii. Approximating realistic bidding (f) Commissioning dates of: i. *Alternative projects* ii. *Committed projects* iii. *Anticipated projects* iv. *Modelled projects* The sensitivity testing should always ensure that relevant reliability standards are met.	of customer reliability i.e. VoLL, VCR. (b) Capital and operating costs of; (i). Alternative projects (ii). Committed projects (iii). Anticipated projects (iv). Modelled projects (c) Discount rate (d) Market demand (e) Generation bidding behaviour using (i). SRMC (ii). Approximating realistic bidding (f) Commissioning dates of: (i). Alternative projects (ii). Committed projects (iii). Anticipated projects (iv). Modelled projects The sensitivity testing should always ensure that relevant reliability standards are met.

(15) The proponent's nominated construction timetable must include a start of construction, construction time and commissioning, where: (i) start of construction means the date at which construction is required to commence in order to meet the commissioning date, taking into consideration the construction time nominated by the proponent; (ii) construction time is the time nominated by the proponent to order equipment and build the project and does not include the time required to obtain environmental, regulatory or planning approval; and (iii) commissioning means the date, nominated by the proponent, on which the project is to be placed into commercial operation.	Not changed from previous version
(16) This version of the regulatory test applies to all applications made after the date of promulgation. All applications commenced prior to the promulgation of this version of the regulatory test are to be determined in line with the previous version of the regulatory test.	Not in previous version.
	Deleted:

	(7) In determining the *market benefit,* the *proposed augmentation* should not pre-empt nor distort potential unregulated developments including network, generation and demand side developments. To this end: (d) a *proposed augmentation* must not be determined to satisfy this test more than 12 months before the *start of construction* date; (e) a *proposed augmentation* will cease to satisfy this test if it has not commenced operation by 12 months after the *commissioning* date unless there has been a delay clearly due to unforeseen circumstances; (f) unless there are exceptional circumstances, *new interconnectors* must not be determined to satisfy this test if *start of construction* is within 18 months of the project's need being first identified in a network's annual planning review or NEMMCO's statement of opportunities (or in some similar published document in the period prior to 13 December 1998). (8) The consultation process for determining whether a *proposed augmentation* satisfies this test must be an open process, with interested parties having an opportunity to provide input and understand how the benefits have been measured and how the decision has been made. Specific consultation is

	required on: (a) identifying *committed projects* and *anticipated projects*; (b) setting input assumptions such as fuel costs and load growth; (c) modelling market behaviour and considering whether the market development scenarios are realistic; (d) the proponent's *construction timetable*; (e) understanding how benefits will be allocated; and (f) understanding how a decision has been made. (9) Any information which may have a material impact on the determination of *market benefit* and which comes to light at any time before the final decision must be considered and made available to interested parties.

Appendix D A Definition of Competition Benefits

Dr Darryl Biggar (Consultant)

Australian Competition and Consumer Commission

It is generally accepted that a transmission augmentation may enhance the overall welfare of participants in the electricity industry (i.e., generators and consumers). It is also generally accepted that in some cases a portion of that total welfare enhancement is due to the effect of the transmission augmentation on competition between generators. But what, exactly, is the best way to isolate that component of the total welfare enhancement of a transmission augmentation that can be attributed to enhanced competition?

First principles

In order to keep this discussion as simple as possible, let's focus on the short-term in which generator and consumer locations and fuel choices are fixed and the transmission network can be taken as fixed.

The NEM dispatch engine operates as follows. Each five minutes it accepts bids and offers from electricity producers and dispatchable load. The dispatch engine then finds the "dispatch" (i.e., the quantity of electricity to be produced or consumed in that five minute interval for each generator and dispatchable load) which maximises the total surplus from trade (i.e., the sum of producers' surplus and consumers' surplus) subject to the physical limitations imposed by the transmission network at that moment in time.[12]

Any augmentation to the transmission network therefore has two primary effects on the dispatch in the short-term:

(a) First, an augmentation to the transmission network changes the physical limitations on the transmission network. The effect of changing these physical limits is normally to allow the dispatch engine to find a dispatch with a higher total surplus.

(b) Second, an augmentation to the transmission network may affect how generators bid into the NEM. In particular, an augmentation to the transmission network may increase competition between existing generators, causing them to submit offers which are closer to short-run marginal cost.

We can separate these two effects by first, considering the new optimal dispatch from a new transmission augmentation, *holding constant* the bids and offers of all generators and dispatchable load. We could subsequently consider the dispatch that results (holding constant the network with the new augmentation) from changing the bids and offers of generators and load.

The former benefits – those benefits that result from a re-allocation of generation and load, holding constant the bids and offers – we could call the "efficiency benefits" from the

12 And certain other constraints such as ramp rates on generators, the availability of ancillary services and so on.

transmission augmentation. The latter benefits – those benefits that result from any changes in the bids and offers from the augmentation, holding constant the network with the augmentation is in place – we could call the "competition benefits".13

Under this approach, the total benefits resulting from any transmission augmentation is broken down into two parts – the "efficiency benefits" arising from the re-dispatch of generation and load made possible by the new augmentation, and the "competition benefits" arising from the change in the bid and offer curves brought about by the new augmentation.

In principle, a regulatory test (at least one which operated over the very short term) would operate in an identical manner. A project satisfies the regulatory test if it maximises the "market benefit" having regard to a number of alternative projects. In this context the "market benefit" referred to in the regulatory test is essentially the same as the "total surplus" (the sum of consumers' surplus and producers' surplus) which is maximised by the NEM dispatch engine.

We can therefore define the various key terms, including competition benefits:

Key Definitions:

For a given potential project, the **"total benefits"** of the project is defined to be the difference in total surplus in the following two network scenarios:

(a) the "status quo network" with bidding which accurately and fully reflects any market power in the status quo network; and

(b) the "augmented network" in which the existing network is augmented with the proposed project with bidding which accurately and fully reflects any market power in the augmented network.

The **"efficiency benefits"** of the project is defined to be the difference in total surplus in the following two network scenarios:

(a) the "status quo network" with bidding which accurately and fully reflects any market power in the status quo network; and

(b) the "augmented network" with bidding assumed to be the same as in the status quo network.

The **"competition benefits"** of the project is defined to be the difference in total surplus arising from the following two network scenarios:

(a) the "augmented network" with bidding assumed to be the same as in the status quo network.; and

13 I could, of course, equally define the competition benefits as arising from the change in total surplus arising from the change in bidding under the status quo network (i.e., without the augmentation) and the efficiency benefits as the change in the total surplus arising from the augmentation, assuming the bidding behaviour that would occur under the augmented network.

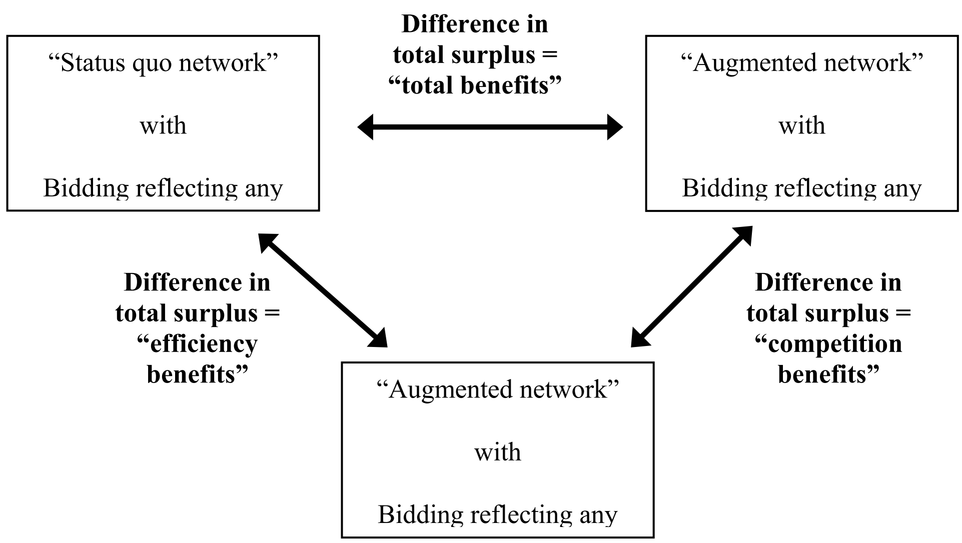
(b) the “augmented network” with bidding which accurately and fully reflects any market power in the augmented network.

It immediately follows from this definition that for any project the total benefit is equal to the sum of the efficiency benefits and the competition benefits:

Total benefits = Efficiency benefits + Competition benefits

The relationship between total benefits, efficiency benefits and competition benefits can be illustrated in the following diagram:

Total benefits = Efficiency benefits + Competition benefits

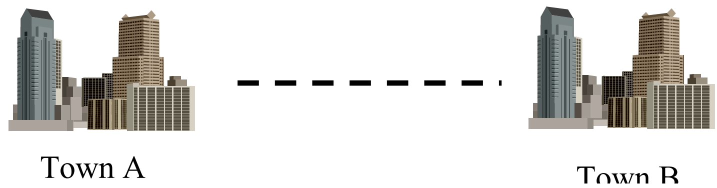


Appendix E Calculating Competition Benefits: A two town example

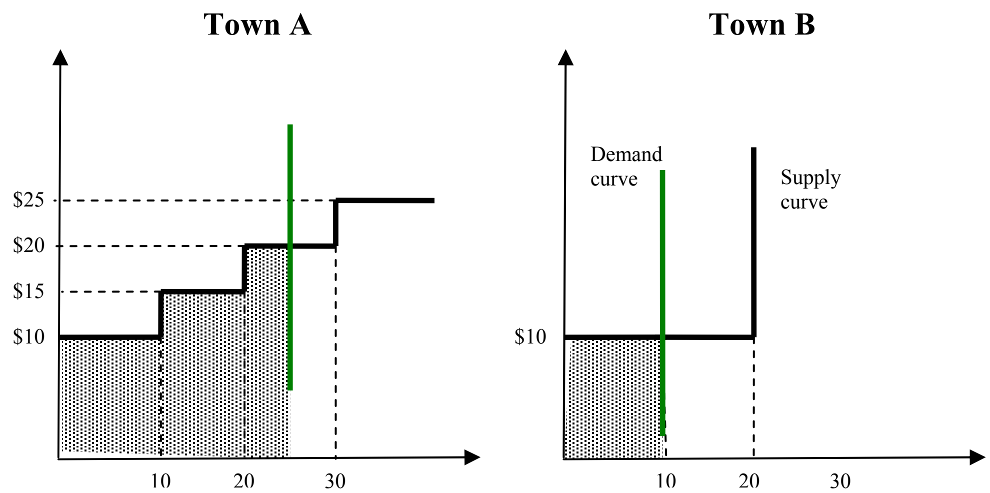
Dr Darryl Biggar (Consultant)

Australian Competition and Consumer Commission

The following examples illustrate how the proposed definition of competition benefits might work in practice. Suppose that we have electricity industry comprising two towns with no electricity transmission links between them. Let's suppose that town A has a generation industry with 40 MW of generation capacity comprising 10 MW with a marginal cost of $10/MWh, 10 MW at $15/MWh, 10 MW at $20/MWh and 10 MW at $25/MWh. Town B is assumed to have 20 MW of generation capacity at $10/MWh marginal cost.



We will assume first that both towns have a highly competitive generation industry. As a result all generators bid their short-run marginal cost curve.14 The resulting industry supply curves are as indicated in the diagram below. Finally, let's suppose that there is 25 MW of load in town A and 10 MW of load in town B. The resulting market price is $20/MWh in town A and $10/MWh in town B as indicated in the diagram below.

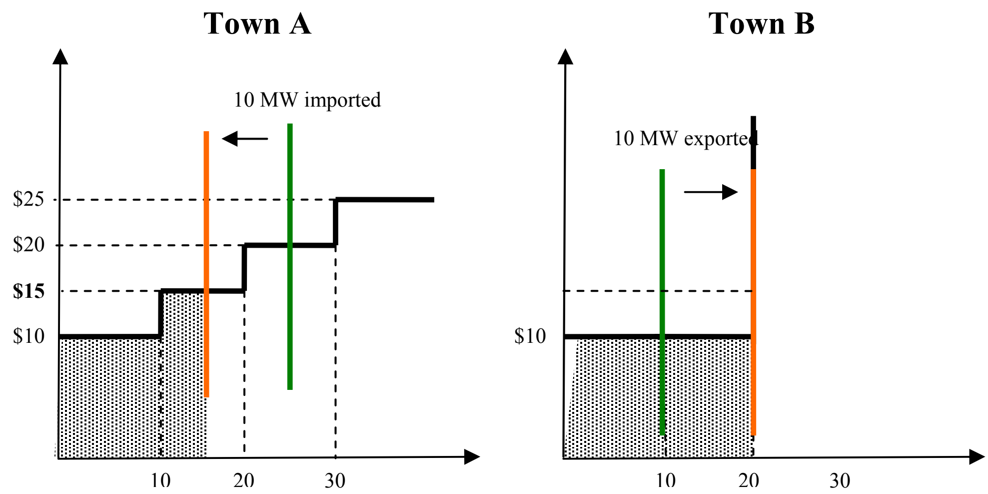


14 For simplicity of exposition, let's assume no fixed costs so that there is no issue of fixed-cost recovery.

In a context such as this, where demand is perfectly inelastic, the maximisation of total surplus is equivalent to the minimisation of total generation costs. Therefore we will explore the effect of a new transmission link between the towns on the total generation cost.

Given the assumptions above the total cost of generation sufficient to meet demand is $350 (10x$10+10x$15+5x$20) for town A and $100 (10x$10) for town B, for a total cost of $450 (illustrated by the shaded area in the diagram above).

Now consider the effect of constructing a new transmission link between town A and B with at least 10 MW of capacity. For simplicity, let's ignore the effect of losses on this transmission link. Now the new efficient dispatch is for the higher-cost generators in town A to shut-down or reduce their output and for the generators in town B to increase their output (by 10 MW). The new optimal dispatch is for town B to produce 20 MW and town A to produce 15 MW. The spot price of electricity in both towns is now equalised at $15/MWh. The total cost of generation is now $175 (10x$10+5x$15) for town A and $200 (20x$10) for town B, for a total cost of generation of $375.



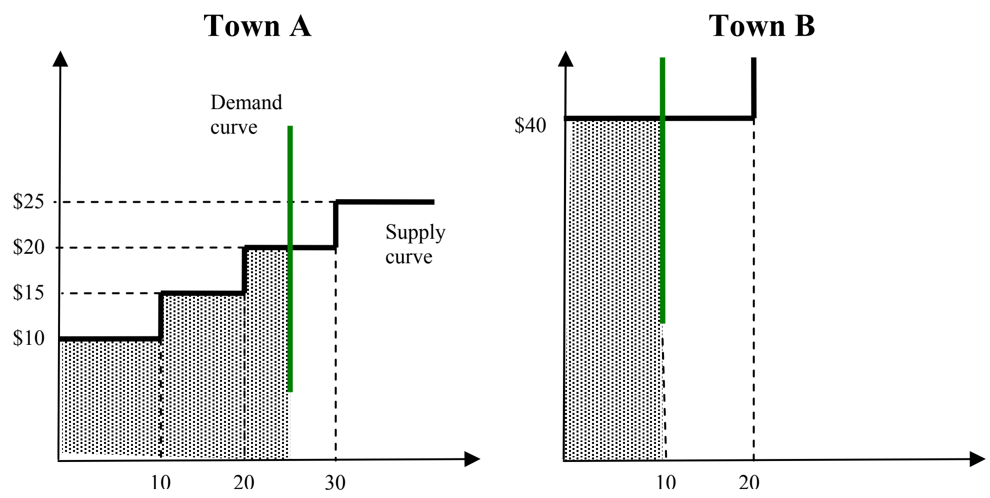
The effect of the transmission link is therefore to reduce the total cost of generation by $75. So, using the definition above, the "efficiency benefit" of this transmission link is $75. Since the generation sectors of each town are assumed to be competitive before and after the transmission link is constructed, there is no change in the bids submitted by the generators in response to the transmission link, so there is no "competition benefit" in this case. The total benefit of the link is just the benefit resulting from more efficient dispatch – in this case, $75.

Table 1: Case A: Perfect competition in both towns

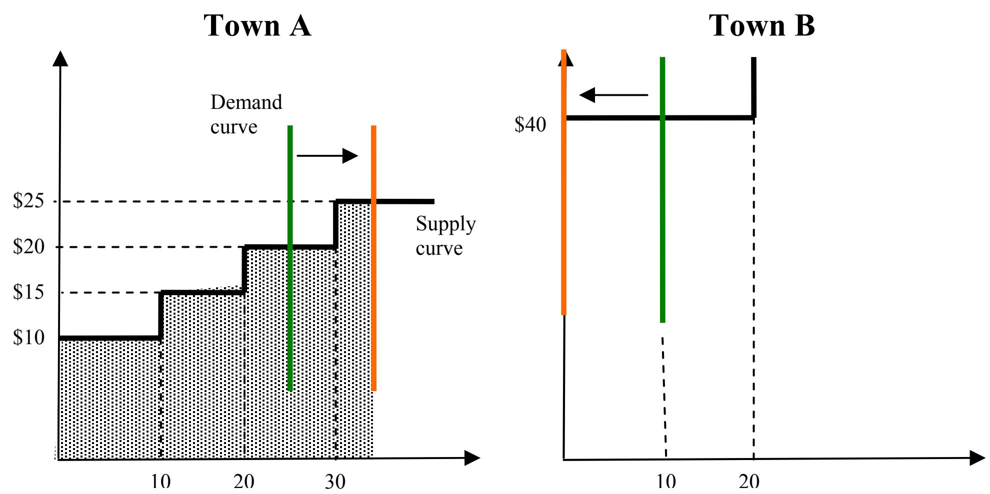
Efficiency Benefit	$75
Competition Benefit	$0
Total Benefit	$75

Let's change this example slightly to illustrate how a competition benefit might arise. Let's suppose now that the generation sector in town B consists of a single monopoly generator with 20 MW of capacity at $10/MWh. Let's suppose that this generator initially charges a price of $40/MWh to satisfy the local demand of 10 MW. This is equivalent, in this context, to submitting a bid with a marginal cost of generation at $40/MWh.

Under these assumptions the (apparent) total cost of generation is $350 in town A (same as before) and $400 (10x$40) in town B for a total cost of $750.

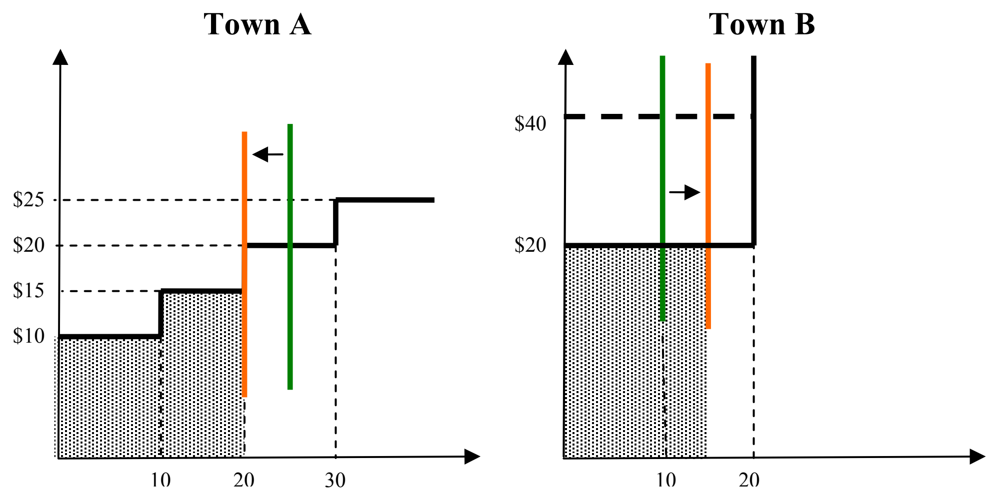


Now consider the effect of building a transmission link. Let's first suppose that we assume that the monopolist in town B does not change its bids after the link is constructed. Since the generation in town A is cheaper the new optimal dispatch is for town A to increase its output by 10 MW and for the generator in town B to shut down. The spot price in both regions equalises at $25/MWh. The resulting dispatch has a total cost of generation of $575 for town A (10x$10+10x$15+10x$20+5x$25) and zero for town B. The "efficiency benefit" is therefore $175 ($750-$575).



But the monopolist is town B would be unlikely to lose all its business to generators in town A without some competitive response. If the monopolist cuts his price he will be dispatched for at least some of his output. If he cuts his price to (just under) $25 he will be dispatched 5 MW, to $20 he will be dispatched 15 units, and at $15 he will be dispatched for his full 20 MW. Of these three choices, her most profitable option is to cut the price to (just under) $20 and to sell 15 units.15 The monopolist therefore decides to cut her bid from $40 to $20.

Now the optimal dispatch is for generators in town A to be dispatched 20 MW and for generators in town B to be dispatched 15 MW. The total cost of generation is $250 (10x$10+10x$15) for town A and $300 (15x$20) for town B, for a total cost of $550. This is lower than the previous case by a further $25, so the "competition benefit" in this case is $25.



In this example, the total benefit of the transmission link is $200 of which $175 is attributable to "efficient benefits" (the link allows low cost generation to be dispatched ahead of high cost generation) and $25 is attributable to "competition benefits" (the link induces the generator with market power to lower its bids closer to marginal cost. Note that the generator with market power does not have to be forced to reduce its bid all the way to SRMC in order for there to be a competition benefit.

Table 2: Case B: Perfect competition in town A, monopoly in town B

Efficiency Benefit	$175
Competition Benefit	$25
Total Benefit	$200

This example shows that it is possible to have an efficiency benefit without a competition benefit. But the converse is not true. It is not possible to have a competition benefit without an efficiency benefit. The reason is as follows. In order to have any competition benefit at least one generator must change its bidding pattern in the direction of marginal cost. But a generator with market power will not reduce its bids unless failure to do so will result in the

15 The profit of the monopolist is (price minus marginal cost) times quantity. Since the marginal cost is $10, cutting the price to (just under) $25 gives a profit of (25-10).5 = $75; cutting the price to $20 gives a profit of (20-10).15=$150; cutting the price to $15 gives (15-10).20=$100. Of these, the greatest profit is earned at the price of $20.

loss of an unprofitable amount of business. In other words, a generator will only reduce its bids if it would lose a significant proportion of its business holding its bid constant. There must be some re-allocation of dispatch holding the bids constant (which implies some efficiency benefit) in order for a generator with market power to be induced to lower its bid (which implies a competition benefit).

Appendix F Calculating Competition Benefits: A general framework

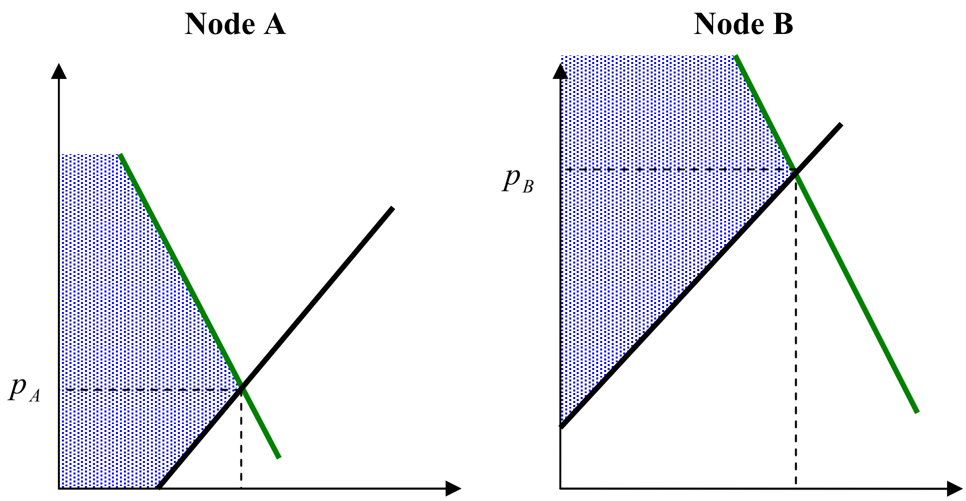
Dr Darryl Biggar (Consultant)

Australian Competition and Consumer Commission

The example in the body of the text used a very simple scenario with constant marginal cost and perfectly inelastic demand. It may be useful to demonstrate the calculation of the competition benefits in an electricity industry with downward-sloping demand and upward-sloping supply.

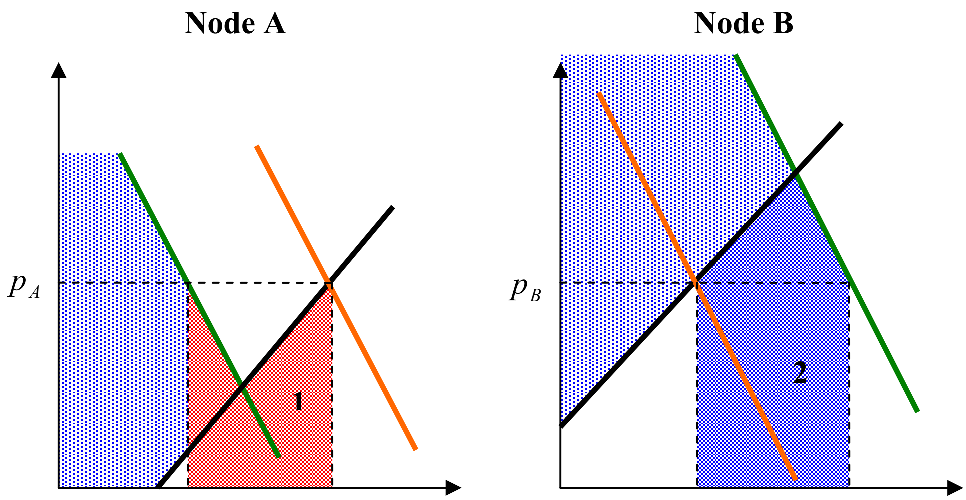
As before, to keep things simple I assume a simple electricity industry with two nodes which are not, initially connected by any transmission links. Node A has a competitive generation industry; node B has a monopoly generator, although this is not, for the moment, important for the analysis. All transmission losses are ignored.

As before, each generator submits an offer curve and each consumer submits a bid curve. The resulting aggregate supply and demand curves at each node are as illustrated in the following diagram. The supply curves are in black and the demand curves are in green. The dispatch engine chooses the spot prices which maximise total surplus. These prices are where supply and demand intersect at each node. The total surplus at each node is the shaded blue region. (Total surplus is the area under the demand curve less the area under the supply curve).



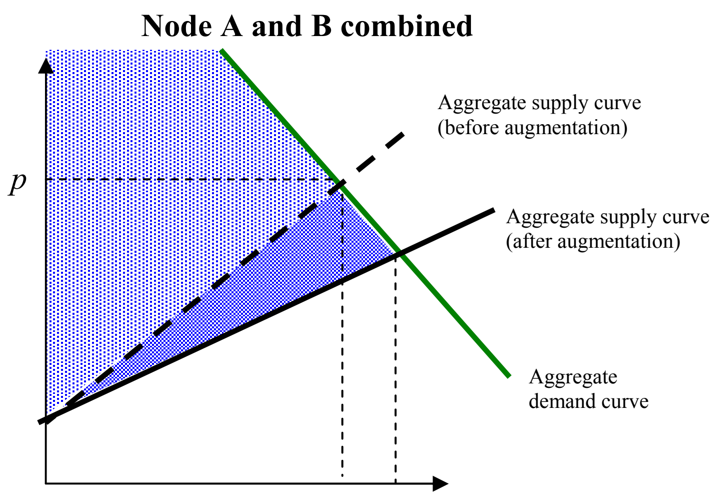
Now consider what happens when a transmission link (of sufficient capacity) is constructed between node A and node B. Generators at node A can now increase their output and export to node B. The generator at node B is required to reduce its output. This continues to the point at which the prices at each node is equalised.

The resulting increase in total surplus at node B is indicated as the dark-blue shaded region, labelled “2”. The drop in surplus at node A is indicated by the dark-red shaded region, labelled “1”. Since the amount exported by node A is the same as the amount imported at node B, the two regions "1" and "2" have the same width. Since the height of region "1" is everywhere less than (or equal to) the common spot price and the height of region "2" is everywhere greater than (or equal to) the common spot price, it is clear therefore that the size of the dark blue region ("2") exceeds the size of the dark-red region ("1"). The amount of this difference is the efficiency benefit from this transmission augmentation.



Under the scenario above, the generator at node B is forced to reduce its output. It is likely to respond to this reduction in output by lowering its bid resulting in a new supply curve at node B (this is the competition effect from this augmentation).

The easiest way to see this effect is to aggregate the demand and supply at both nodes into one diagram (this is possible because, since there is no transmission congestion or losses, node A and node B are in effect the same node). The total surplus is increased by the area of the dark-blue region. This is precisely the amount of the competition benefit.



It is also possible (although much less clear) to present the competition benefit at node A and node B separately. The effect of the transmission augmentation is to change the bidding behaviour of the generator at node B. This is reflected in a drop in the supply curve at node B. This, in turn, causes a new lower pool price and a re-dispatch of generation. Generation at node B increases and generation and node A decreases. The drop in generation at node A is a net increase in surplus (relative to the previous case) equal to the area labelled “1” in the following diagram.

The drop in generation at node A is more than offset by an increase in generation at node B. Generation at node B increases both to offset the fall in generation at node A and to meet the additional demand brought about by the new lower pool price. The additional demand brought about by the lower pool price increases surplus by an amount equal to the areas shaded “3) in the diagram below.

Since the width of area 2 is the same as the width of areas 1 and 3 combined (since the total reduction in output at node A must be equal to the total increase in output at node B) and since the height of area 2 is everywhere less than or equal to the common price while the height of area 3 is everywhere greater than or equal to the common price, it is clear that the combined area of the increase in surplus (area “1” plus “3”) exceeds the cost of the extra output (area “2”).

Finally, the reduction in the cost of generating the existing output is reflected as the increase in surplus labelled “4” in the diagram. The total competition benefit in this case is therefore precisely equal to the sum of areas 1+3+4 less area 2 and is always positive.