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Australian Competition & Consumer Commission

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24 September 2001

# Applications for authorisation of amendments to the National Electricity Code - Network pricing and market network service providers determination (Authorisation Nos A90704, A90705 and A90706)

On 26 July 1999, the Australian Competition and Consumer Commission (the Commission) received applications for authorisation (A90704, A90705 and A90706) of changes to the National Electricity Code (code). The applications were submitted by the National Electricity Code Administrator (NECA) under Part VII of the *Trade Practices Act 1974* (TPA). The proposed amendments to the code outlined in the applications deal with arrangements to allow the participation of market network service providers (MNSPs) in the National Electricity Market (NEM).

At the same time, NECA also submitted an application to vary the NEM access code (access code) to encompass changes to the network connection and network pricing arrangements. The authorisation and access code applications were amended on 18 August 1999, at which time NECA also sought authorisation of the network pricing code changes and an approval to vary the access code to take into account the MNSP code changes.

NECA requested that interim authorisation be granted to those elements of the code required to facilitate the introduction of MNSPs to the NEM. The Commission granted interim authorisation to the MNSP provisions in chapters 2, 3, 4 and 7 of the code on 6 October 1999; and to the MNSP provisions in chapters 5 and 6 of the code on 25 January 2000. In response to concerns about the interpretation of the conditions of authorisation imposed on 25 January 2000, the Commission revoked and regranted the interim authorisation on 23 February 2000.

Enclosed is a copy of the Commission's determination in respect of these applications for authorisation. The Commission's determination outlines its analysis and views on the proposed Code changes.

In its review of these code changes, the Commission has identified a number of provisions that will detract from the public benefit or increase the level of anti-competitive detriment attributable to the implementation of these arrangements. Therefore, the Commission proposes to grant authorisation, conditional upon a number of amendments to the proposed changes being made. The conditions are specified in Chapter 11 of the determination. The Commission proposes to limit the period of the authorisations to 31 December 2010, except for those code changes that have earlier termination dates.

In accordance with s.101 of the *Trade Practices Act 1974* a person dissatisfied with the Commission's determination may apply to the Australian Competition Tribunal for a review of the determination. Each application must be lodged on the appropriate form within 21 days of the date of the determination, with the Registrar of the Tribunal. The Tribunal is located in the Office of the Registrar of the Federal Court in each State.

A copy of this letter together with the determination will be placed on the Public Register kept by the Commission.

Yours sincerely

Michael Rawstron
General Manager
Regulatory Affairs – Electricity

# Applications for Authorisation

# Amendments to the National Electricity Code

# Network pricing and market network service providers

**Date: 21 September 2001**

| **Authorisation nos:** | **Commissioners** |
|---|---|
| A90704 | Fels |
| A90705 | Shogren |
| A90706 | Martin |

**File no:**
C1999/441

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# Glossary

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|---|---|
| AARR | Aggregate Annual Revenue Requirement |
| ABARE | Australian Bureau of Agriculture and Resource Economics |
| ACCC | Australian Competition and Consumer Commission |
| ACF | Australian Conservation Foundation |
| AEA | Australian EcoGeneration Association |
| AGO | Australian Greenhouse Office |
| Bardak | Bardak Energy Services |
| BDB | Basslink Development Board |
| BPL | Basslink Proprietary Limited |
| BCA ERTF | Business Council of Australia Energy Reform Taskforce |
| code | National Electricity Code |
| Commission | Australian Competition and Consumer Commission |
| CRNP | Cost Reflective Network Pricing |
| Delta | Delta Electricity |
| DNSP | Distribution Network Service Provider |
| DUOS | Distribution Use of System |
| ElectraNet | ElectraNet SA |
| Embedded | Connection within a distribution system |
| EMRI | Electricity Markets Research Institute |
| ENERGEX | ENERGEX Limited |
| Ergon | Ergon Energy |
| GWh | Giga Watt hour |
| Hazelwood | Hazelwood Power |
| Hydro | Hydro Tasmania |
| IPA | Institute of Public Affairs Limited |
| IPART | Independent Pricing and Regulation Tribunal (NSW) |
| IRPC | Inter Regional Planning Committee |
| kW | kilo Watt |
| LE | London Economics |
| Loy Yang | Loy Yang Power |
| LRMC | Long Run Marginal Cost |
| MLF | Marginal Loss Factor |
| MVA | Mega Volt Ampere |
| MW | Mega Watt |
| MWh | Mega Watt hour |
| MNSP | Market Network Service Provider |
| NECA | National Electricity Code Administrator |
| NECA's Review | NECA's Transmission and Distribution Pricing Review |
| NEDF | National Electricity Distributors Forum |
| NEM | National Electricity Market |
| NEMMCO | National Electricity Market Management Company Limited |
| NERA | National Economic Research Associates |
| NGF | National Generator Forum |
| NSP | Network Service Provider |
| NSW Treasury | New South Wales Treasury Market Implementation Group |
| ORG | Victorian Office of the Regulator-General |
| Origin | Origin Energy |

| | |
|---|---|
| Powerlink | Powerlink Queensland |
| QLD Treasury | Queensland Treasury |
| RIEMNS | Review of the Integration of Energy Markets and Network Services |
| SA Treasury | South Australian Department of Treasury and Finance |
| Several Vic DBs | Several Victorian Distribution Businesses - Citipower, Eastern Energy (now TXU Australia), Powercor and United Energy (also includes AGL Electricity in its subsequent submission on the draft determination.) |
| Snowy | Snowy Hydro Trading Proprietary Limited |
| Stanwell | Stanwell Corporation Limited |
| SRMC | Short Run Marginal Cost |
| Tarong | Tarong Energy |
| Tas Treasury | Tasmanian Department of Treasury and Finance |
| TCC | Transmission Congestion Contract |
| TNSP | Transmission Network Service Provider |
| TPA | *Trade Practices Act 1974* |
| Transend | Transend Networks Proprietary Limited |
| TransEnergie | TransEnergie Australia Proprietary Limited |
| TUOS | Transmission Use of System |
| VAW | VAW Kurri Kurri Proprietary Limited |
| VENCorp | Victorian Energy Networks Corporation |

# Overview

## 1. The application

On 26 July 1999, the Australian Competition and Consumer Commission (the Commission) received applications for authorisation (A90704, A90705 and A90706) of changes to the National Electricity Code (code). The applications were submitted by the National Electricity Code Administrator (NECA) under Part VII of the *Trade Practices Act 1974* (TPA). The proposed amendments to the code outlined in the applications deal with arrangements to allow the participation of market network service providers (MNSPs) in the National Electricity Market (NEM).

At the same time, NECA also submitted an application to vary the NEM access code (access code) to encompass changes to the network connection and network pricing arrangements. The authorisation and access code applications were amended on 18 August 1999, at which time NECA also sought authorisation of the network pricing code changes and an approval to vary the access code to take into account the MNSP code changes.

The network pricing and MNSP code changes were drafted in accordance with NECA's final report from its Transmission and Distribution Pricing Review (NECA's review).

NECA requested that interim authorisation be granted to those elements of the code required to facilitate the introduction of MNSPs to the NEM. The Commission granted interim authorisation to the MNSP provisions in chapters 2, 3, 4 and 7 of the code on 6 October 1999; and to the MNSP provisions in chapters 5 and 6 of the code on 25 January 2000. In response to concerns about the interpretation of the conditions of authorisation imposed on 25 January 2000, the Commission revoked and regranted the interim authorisation on 23 February 2000.

Authorisation under Part VII of the TPA provides immunity from court action for certain types of market arrangements or conduct which would otherwise be in breach of Part IV of the TPA. Authorisation is granted where the Commission concludes that the public benefits of the arrangements or conduct would outweigh the anti-competitive detriment of such arrangements or conduct.

The Commission has prepared this determination outlining its analysis and views on the applications for authorisation of the network pricing and MNSP code changes.

## 2. Importance of efficient network pricing

The code's network pricing arrangements are a key component of the NEM design and impact on the ability of the code to deliver public benefits through efficient utilisation of and investment in network assets, as well as optimal electricity production and consumption decisions. The network pricing arrangements will also impact on the effectiveness of the NEM access regime. An effective access regime is also essential to the realisation and pass through of the benefits of upstream and downstream reform and competition.

The transmission and distribution networks are traditionally considered to be natural monopolies, however, alternatives to network facilities exist in some situations, such as embedded generation and demand side management. The code's network pricing arrangements will impact on the ability of non-network alternatives to compete effectively with network service providers (NSPs).

Also, as it is possible to establish a market-based approach to the provision of network services in certain circumstances, the proposed arrangements for pricing prescribed network services will impact on the ability to have efficient competition between MNSPs and regulated NSPs and non-network alternatives.

The Commission is of the view that transmission network pricing arrangements should be designed to reflect the level of utilisation at different points on the transmission network so as to provide effective market price signals for:

- use of existing network facilities;
- network augmentation or investment in alternatives in congested parts of the network; and
- location of generation, MNSPs and load in areas that do not increase the congestion on network assets.

It is important that any signals arising from transmission prices are transferred through to end use customers and are not distorted by the distribution pricing arrangements.

To encourage efficient behaviour, network users should be exposed to the marginal cost of their network usage, through a combination of network charges and any other network related price signals present in the NEM. Given the large fixed costs involved in electricity networks, it is likely that there will be residual costs that need to be recovered by transmission network service providers (TNSPs). The Commission considers that such costs need to be recovered in a way that preserves the price signals already present and minimises distortions to network users' decisions.

## 3. Commission's assessment of the code changes

In assessing the proposed code changes the Commission is mindful of the need to manage the transition from the current (mainly jurisdiction) arrangements to an effective NEM wide network pricing regime. The Commission considers that the proposed code changes, subject to some modification, can provide a first step towards an effective and integrated network pricing regime.

### *Usage charges*

The current code provisions require TNSPs to calculate transmission charges using a combination of cost reflective network pricing (CRNP) and average pricing (postage stamping). NECA's review concluded that there are deficiencies in this approach and that it should be replaced with provisions that allow TNSPs to select a transmission use of system (TUOS) usage charge from a range of prices calculated using CRNP, utilisation adjusted CRNP and long run marginal cost (LRMC). NECA proposed that

TUOS usage charges should only be levied on transmission customers. NECA proposed that the residual costs should be recovered from a TUOS general charge, allocated to customers to minimise distortions.

The Commission considers the proposal to employ three alternative cost allocation methodologies for TUOS usage charges invites pricing inconsistencies and encourages perceptions that TNSPs may apply their pricing discretion in a discriminatory manner. The Commission is therefore requiring the proposal for a discretionary price range to be deleted.

In principle the utilisation-adjusted CRNP technique appears superior to the standard CRNP technique but it is as yet untested except in Tasmania. The Commission has therefore required that standard CRNP be retained for the time being as the default technique, but that the utilisation-adjusted technique is permitted where a benefit to the market can be demonstrated.

Consistent pricing is desirable across the NEM. The existing arrangements allow the price calculation to be applied over multiple regions, whereas that option would be removed under the proposed arrangements. The Commission requires that option to be restored.

It is important usage prices take into account signals present elsewhere in the market so as to avoid duplication. The existing arrangements provide for inter-regional residues to be deducted for the purposes of calculating usage prices. The changed arrangements would remove that provision, increasing the risk of duplication of signals. That change must be deleted.

In its draft determination, the Commission noted the inadequacies and inconsistencies in the present transmission usage signals in the NEM and proposed extending usage pricing to all transmission users. A number of responses expressed concern at the substantial nature of the proposal and suggested it might distract from NECA's RIEMNS process that was investigating superior, market based, alternatives. The Commission accepts these are valid concerns and has withdrawn its proposed condition. The transmission usage charge will therefore only apply to customers.

The Commission believes there is scope for improvement of the network pricing arrangements, perhaps through refinement of NECA's proposals. It is requiring NECA to further review the TUOS usage pricing regime and has set down some suggestions and guidelines that it invites NECA and interested parties to consider.

The Commission also notes that the need for economic signals to be provided through transmission usage charges would be diminished if energy market signals were improved. Such improvements may include the introduction of more regions or full nodal pricing in the spot market and firmer and more extensive network-related rights in the forward markets. The Commission is requiring NECA to consider these possibilities in conjunction with its review of TUOS usage pricing.

***General charge***

NECA's code changes would result in the balance of regulated TNSPs' agreed revenue being recovered through TUOS general charges. General charges would be levied only on transmission customers and would be assessed on the basis of a uniform price applied to energy consumed during the year.

The aim of the general charge is to recover the balance of agreed revenue with minimal distortion. The Commission is concerned that customers' behaviour may be influenced if the general charge is based on current energy consumption and has therefore made it a condition of authorisation that the TUOS general charges are levied according to customers' energy consumption in the previous year rather than the current year. This should assist in minimising the impact of the charges on customers' behaviour. The Commission also recognises that an energy-based charge can be distortionary for customers with high load factors. It has required that an alternative capacity-related charge be applied in those instances.

While a number of interested parties submitted that generators should also pay TUOS general charges, the Commission accepts NECA's argument that this may create distortions. The general charge is intended to recover the residual costs of the network in a way that does not impact on the signals delivered through the TUOS usage charge. Further, the Commission considers that there is no benefit, and indeed may be significant detriment, for example to the structure of generation, the energy and ancillary markets, from applying the general charge to generators and MNSPs in addition to customers. The Commission therefore accepts NECA's proposal that TUOS general charges continue to be levied on customers only.

***Common service charge***

A common service is one that cannot reasonably be allocated to network users on a locational basis. Under the existing arrangements, common service costs are recovered through an energy-based charge based on a rate that varies at each connection point according to the assessed utilisation of different networks. The proposed changes require the rate to be uniform for all connection points in a particular network.

The Commission considers it is appropriate for the common service charge to be structured similarly to the general charge. In both cases the primary aim should be to recover the required revenue with minimal distortion. The Commission endorses NECA's proposal to move to a uniform rate, but believes the distortionary impact is reduced if the rate is applied to historical energy consumption rather than present consumption, and if high load factor customers have access to an alternative capacity-based charge.

***Negotiation of price discounts***

The code currently allows TNSPs to negotiate a discount to customers who would otherwise bypass the transmission network. NECA has proposed changes to these arrangements that allow TNSPs to recover the cost of discounted TUOS general charges from remaining transmission customers.

The Commission considers that there are benefits in this approach as it can help minimise the distortionary impact of the general charges. On the other hand there is some risk of negative impacts for the customers who are required to absorb the cost of the discounts. The Commission is requiring that discounts will have to be negotiated in accordance with an even-handed framework and meet guidelines promulgated by the

Commission in order to be eligible for the costs to be recovered from other customers. Further the Commission believes that similar arrangements should apply to the recovery of common service charge discounts. The Commission is also requiring the disclosure of information about discounts offered, so that the remaining customers can assess the impact of the TNSP policies.

***Financial transfers***

The code changes would extend the scope of financial transfers between TNSPs. The Commission is not satisfied of the merit of those proposals, which are less flexible than the present arrangements and may result in distortionary price steps at region boundaries. The Commission has imposed a requirement on NECA to review the prospects for financial transfer arrangements that would (i) support a market-wide user-pays approach to the existing network and/or (ii) support uniform general charges across the market. NECA will be required to conduct the review in accordance with the code consultation procedures and must consult with all code participants and participating jurisdictions.

***Distribution pricing***

NECA’s review addressed the unbundling of TUOS and distribution use of system (DUOS) charges, beneficiaries pay for new investments, negotiation arrangements, and the pass through of avoided TUOS to embedded generators. These issues are discussed in other sections of the determination.

The Commission is concerned that a consistent approach to distribution pricing is yet to emerge. While the Commission acknowledges the work being undertaken by some of the jurisdictional regulators, it considers that there would be public benefits from a consistent approach to distribution pricing and for these arrangements to be within the code.

It is important that the price signals arising from TUOS usage charges should not be distorted by the distribution pricing arrangements. The Commission has imposed a condition of authorisation that the code be amended to require distribution network service providers (DNSPs), where metering installations allow this, to allocate TUOS charges to distribution users in a way that preserves the economic signalling of the TUOS prices.

***New investments – beneficiaries pay***

NECA’s review concluded that there is a mismatch between those who benefit from new investments and those who pay for those investments. It argues that this leads to inefficient investments and inappropriate locational decisions. NECA has therefore proposed code changes that require the beneficiaries of new investments to pay for those investments according to the proportion of benefits that they receive.

The Commission accepts that NECA’s proposals have merit in principle but is concerned that insufficient detail regarding their implementation is known. The Commission has endorsed the beneficiaries pay framework but is requiring the implementation to be delayed until NECA determines satisfactory implementation arrangements.

### *Service standards*

NECA's code changes include provisions requiring NSPs to publish service standards. Appropriate service standards can provide a sound basis for ensuring that NSPs deliver cost-effective levels of service and do not abuse the market power arising from their monopoly position. The Commission considers that, given the absence of adequate property rights and compensation arrangements in the code, it is necessary to impose financial incentives on TNSPs to ensure that they provide the required level of service. The Commission will take service levels into account when regulating transmission revenues.

### *Negotiating framework*

NECA's code changes require each NSP to establish a negotiating framework to apply to the agreement of levels of network services. Conditions imposed by the Commission require this negotiating framework to be extended to other situations in which matters have to be negotiated between network users and regulated NSPs.

### *Information disclosure*

In order to improve information about the composition and structure of network charges, NECA has proposed code changes that allow large customers to request unbundled transmission and distribution charges and for smaller end users to be able to access unbundled information on a customer class basis.

The Commission considers that efficient network pricing arrangements require an effective information disclosure regime so that customers can assess the impact of their network use on their charges and make informed decisions about location and alternatives to network use. The Commission has therefore imposed a number of conditions of authorisation that build on the concept of unbundling TUOS and DUOS charges network charges. The Commission has required that both TNSPs and DNSPs must, upon request, provide customers with information about the method used to calculate network charges and to separately identify the components of the charges.

### *Embedded generation*

To provide locational signals to embedded generators, the proposed code changes require DNSPs to pass through to embedded generators the full reduction in TUOS usage charges that arises from the generator being located within the distribution network.

The Commission supports the principle of compensating embedded generators for the benefits that they deliver to the network, in terms of avoided augmentation. The Commission has imposed conditions to ensure the provisions have effect immediately and will take into account the new arrangements for allocating network augmentation costs to beneficiaries.

### *Market network service providers*

NECA's review developed a framework for the participation of MNSPs (unregulated interconnectors). These interconnectors earn their revenue from participating in the wholesale spot market rather than levying network charges. The code changes set out safe harbour provisions that allow a market network service to be automatically approved if it meets these criteria.

The Commission considers that there are public benefits from NECA's proposal to allow MNSPs to operate in the NEM. MNSPs will provide a source of competition for generators in an importing region and facilitate inter-regional trading where the owner of the MNSP sells financial hedges to market participants. The Commission supports NECA's proposal to restrict regulated interconnectors from converting to a market network service. This is due to concerns that regulated TNSPs may be able to leverage off their existing transmission network to make windfall gains, at the expense of their transmission connected customers.

## 4. Conclusions

The TPA enables the Commission to grant authorisation for arrangements that would otherwise be in breach of Part IV of the TPA. In reaching its decision on whether or not to grant authorisation the Commission has examined the code changes carefully in order to assess the potential public benefits arising from the code changes against the possible anti-competitive detriments. The Commission has taken into account submissions it has received from the applicant and other interested parties, discussions with interested parties and advice from its consultants.[1]

In its original authorisation of the code (10 December 1997) the Commission expressed its concerns that the code's network pricing arrangements provide little incentive for the efficient location of investment in network or generation options. The Commission stated that:

> The Commission's acceptance of the applicants' position has been on the basis that the code will deliver overall public benefits provided the concerns of users will be addressed in, and the necessary code changes will be made as a result of, NECA's review of network pricing. However, if the NECA review is unable to deliver code changes which result in a more efficient set of network prices, then the expected balance between public benefit and anti-competitive detriment may be materially different and may provide grounds for the Commission to revoke this authorisation.

The Commission considers that its original concerns regarding investment and location incentives have not yet been fully addressed. The Commission has therefore imposed conditions of authorisation to address these concerns and require further work on the scope for improvement of the network pricing arrangements. Such work will consider:

- greater integration of transmission signals into the energy markets;
- improved usage pricing;
- an effective beneficiaries-pay approach to new network investments; and
- financial transfers to support a market-wide user-pays approach to the existing network and uniform general charges.

1 The Commission has received advice from Dr Robert Outhred and Professor Stephen King.

Apart from the above concerns, the Commission has identified some other issues that detract from the public benefit of the network pricing arrangements and which must also be addressed. Chapters 4-10 of this determination set out the details of the Commission's analysis of the proposed code changes and the Commission's decision, including the conditions of authorisation, are contained in chapter 11.

# 1. Introduction

On 26 July 1999, the Commission received applications for authorisation (A90704, A90705 and A90706) of changes to the code. The applications were submitted by the NECA under Part VII of the TPA. The proposed amendments to the code deal with arrangements to allow the participation of MNSPs in the NEM.

At the same time, NECA also submitted an application to vary the NEM access code (access code) to encompass changes to the network connection and network pricing arrangements. The authorisation and access code applications were amended on 18 August 1999, at which time NECA also sought authorisation of the network pricing code changes and approval to vary the access code to take into account the MNSP code changes. The network pricing and MNSP code changes were drafted in accordance with NECA's review.

NECA requested that interim authorisation be granted to those elements of the code required to facilitate the introduction of MNSPs to the NEM. The Commission granted interim authorisation to the MNSP provisions in chapters 2, 3, 4 and 7 of the code on 6 October 1999; and to the MNSP provisions in chapters 5 and 6 of the code on 25 January 2000. In response to concerns about the interpretation of the conditions of authorisation imposed on 25 January 2000, the Commission revoked and regranted the interim authorisation on 23 February 2000.

Authorisation under Part VII of the TPA provides immunity from court action for certain types of market arrangements or conduct that would otherwise be in breach of Part IV of the TPA, where the Commission concludes that the public benefits of the arrangements or conduct would outweigh the anti-competitive detriments of such arrangements or conduct.

The Commission has prepared this network pricing and MNSP determination outlining its analysis and views on the applications for authorisation of the code changes. Chapter 2 of this determination sets out the statutory test that the Commission must apply when assessing an application for authorisation. Chapter 3 describes the Commission's public consultation process. The Commission's analysis of the code changes is set out in chapters 4-10 and the Commission's determination is in chapter 11.

## 2. Statutory test

The applications were made under sub-sections 88(1) and 88(8) of the TPA.

Applications made under sub-section 88(1) of the TPA are for authorisation to make a contract or arrangement, or arrive at an understanding, a provision of which would have the purpose, or would or might have the effect, of substantially lessening competition within the meaning of section 45 of the TPA; and to give effect to a provision of a contract, arrangement or understanding where the provision is, or may be, an exclusionary provision within the meaning of section 45 of the TPA. Further sub-section 88(6) provides that an authorisation made under sub-section 88(1) has effect as if it were also an authorisation in the same terms to every other person named or referred to in the application.

Applications made under sub-section 88(8) of the TPA are for authorisation to engage in conduct that constitutes, or may constitute, the practice of exclusive dealing in accordance with the provisions of section 47 of the TPA. Further, sub-section 88(8AA) provides that where authorisation has been granted under sub-section 88(8) and this particular conduct is expressly required or permitted under a code of practice, the authorisation applies in the same terms to all other persons named or referred to as a party or proposed party to the code. Authorisations may also apply to any corporation who becomes a party in the future.

The TPA provides that the Commission shall only grant authorisation if the applicant satisfies the relevant tests in sub-sections 90(6) and 90(8) of the TPA. While sub-section 90(6) and sub-section 90(8) relate to different types of anti-competitive behaviour, the tests are essentially the same.

Sub-section 90(6) provides that the Commission shall grant authorisation only if it is satisfied in all the circumstances that:

- the provisions of the proposed contract, arrangement or conduct would result, or be likely to result, in a benefit to the public; and
- that benefit would outweigh the detriment to the public constituted by any lessening of competition that would, or would be likely to result from the proposed contract, arrangements or conduct.

Sub-section 90(8) provides that the Commission shall grant authorisation only if it is satisfied in all the circumstances that the proposed provision or conduct would result, or be likely to result, in such a benefit to the public that the proposed contract, arrangement, understanding or conduct should be allowed.

The detriment to be considered is limited to detriment caused by a lessening of competition. However, consideration of public benefits is less restricted and public benefits recognised in the past include:

- fostering business efficiency;
- industry rationalisation;

- promotion of industry cost savings;
- promotion of competition in industry;
- promotion of equitable dealings in the market;
- expansion of employment;
- development of import replacements;
- growth in export markets;  and
- arrangements which facilitate the smooth transition to deregulation.

In considering whether or not to grant authorisation the Commission must consider what the position is likely to be in the future if authorisation is granted and what the future is likely to be if authorisation is not granted.

If the Commission determines that the public benefits do not outweigh the detriment to the public constituted by any lessening of competition, the Commission may refuse authorisation or grant authorisation subject to conditions.

The value of authorisation for the applicant is that it provides protection from action by the Commission or any other party for potential breaches of certain restrictive trade provisions of the TPA.  It should be noted, however, that authorisation only provides exemption for the particular conduct applied for and does not provide blanket exemption from all provisions of the TPA.  Further, authorisation is not available for misuse of market power (section 46).

For more detail about the Commission's authorisation process and the statutory test that the Commission applies please see: *Guide to authorisations and notifications*, Australian Competition and Consumer Commission, November 1995.

# 3. Commission's processes

The Commission has a statutory obligation under the TPA to follow a public process when assessing an application for authorisation.

In response to NECA's network pricing code changes the Commission released an issues paper titled *Issues Paper: Applications for authorisation, application to vary an access code – National Electricity Code, Network Pricing code changes.* The purpose of the issues paper was to facilitate public discussion on the competition, access and public benefit implications of the proposed code changes.

The Commission received the initial application for authorisation of the MNSP code changes on 26 July 1999. At this time, NECA also submitted an application to vary the access code to encompass changes to the network connection and network pricing arrangements. Notification of the applications and a request for submissions were made through newspaper advertisements and the Commission's website.

The authorisation applications were amended on 18 August 1999 to incorporate the network pricing code changes and to make some other minor amendments. Interested parties had already been asked to make submissions on the network pricing code changes with respect to the access code application. The Commission notified interested parties of the amendments to the applications through its website and extended the deadline for submissions from 30 August 1999 to 17 September 1999.

The Commission received submissions from 27 different parties on the network pricing and MNSP code changes. Appendix A contains a list of the parties who made submissions to the Commission. All submissions have been placed on the public register, with the exception of part of one, which was excluded on confidentiality grounds.

NECA provided the Commission with the final report from its review in support of the applications. These documents were also placed on the public register for inspection by interested parties.

The Commission produced a draft determination on 12 December 2000 outlining its analysis and views on the authorisation application. Following a request for a conference by TransGrid, the pre-determination conference was held in Canberra on 15 March 2001. In excess of 60 interested parties attended the conference[2].

Interested parties were given an opportunity to lodge further submissions with the Commission following the pre-determination conference. The Commission received submissions from 31 interested parties addressing issues raised at the conference or in the draft determination (see appendix A). This determination takes into account the issues raised at the pre-determination conference and in these submissions.

[2] For the purposes of the conference, an interested person is a person who has notified the Commission in writing that the person, or a specified unincorporated association of which the person is a member, claims to have an interest in the applications and the Commission is of the opinion that the interest is real and substantial.

The Commission has released this final determination outlining its analysis and views on the application for authorisation according to the statutory assessment criteria set out in Chapter 2. A person dissatisfied with the final determination may apply to the Australian Competition Tribunal for its review.

# 4. Transmission network pricing

## 4.1 Issues for the Commission

The code's network pricing arrangements are a key component of the NEM design and impact on the ability of the code to deliver public benefits through efficient utilisation of and investment in network assets, as well as optimal electricity production and consumption decisions.

The pricing of transmission network services is also a crucial element of the access regime in the NEM and is essential to the realisation and pass through of the benefits of upstream and downstream reform and competition.

The transmission networks are traditionally considered to be natural monopolies, however, alternatives to network facilities exist in some situations, such as embedded generation and demand side management. The code's network pricing arrangements will impact on the ability of non-network alternatives to compete effectively with TNSPs.

## 4.2 TUOS usage charges

The proposed code changes replace the current CRNP component of TUOS charges with a TUOS usage charge. This charge is selected by the TNSP from a price range for each connection point that reflects capacity utilisation or, in other words, the longer term investment conditions at each connection point. This price range will be determined by:

1. The existing CRNP method, where the cost to be allocated for each transmission element is set at 50% of the annual costs attributed to that element.

2. A utilisation adjusted CRNP method, where the cost to be allocated is set to the full annual cost for heavily utilised elements and is discounted by up to 100% for under-utilised elements.

3. The direct calculation of the LRMC derived from the knowledge of future investment plans and the anticipated load growth and generation development that underpins the plan.

The TNSPs would choose a price from within this range after the Commission, as the regulator of transmission network revenues, has determined that the price range was developed consistently with the code's principles.

There has been no change made to the incidence of TUOS charges, which continue to be levied on customers only, although NECA has proposed that new investments be recovered on a beneficiaries pay basis.

### 4.2.1 What the interested parties say

*All users should pay usage charges*

The Australian Cogeneration Association (now known as the Australian EcoGeneration Association (AEA)) supports a user pays approach to the allocation of sunk network costs and considers that such an approach would be consistent with the approach on ancillary services. The AEA considers that generators should contribute to the sunk costs since they are significant beneficiaries of the existing transmission system. The AEA disagrees with assertions that generators do not benefit from the existing transmission system, arguing that their continued requests for property rights is indicative of the value they place upon the existing system.

The Australian Greenhouse Office (AGO) argues that generators should be liable to pay a share of TUOS charges since they benefit from the transmission network and it would improve locational signalling in the NEM. The AGO argues that this could be achieved by requiring generators to pay for the service from their connection point up to the regional reference node and for customers to pay the remainder.

Several of the Victorian Distribution Businesses – Citipower, Eastern Energy (now TXU Australia), Powercor and United Energy (Several Vic DBs)[3] – jointly submit that transmission capacity is a function of both the level and location of generation and demand, and that transmission charges should therefore be allocated to both groups of transmission network users.

Several Vic DBs also argue that generators should be required to pay at least fifty per cent of TUOS charges. They state that requiring generators to pay TUOS charges is consistent with user pays principles, and that remote generators that use more of the transmission system should pay more than generators that are located closer to loads.

The AEA, Business Council of Australia Energy Reform Taskforce (BCA ERTF) and Ergon Energy (Ergon) argue that NECA's proposal that generators be exempt from paying TUOS is in conflict with the objectives in the code.

Ergon believes that the framework used to recover sunk costs from customers can be applied to generators and should be implemented as soon as possible.

The Australian Conservation Foundation (ACF) advocates that, as with other competitive markets, generators should pay for the sunk transmission assets that transport their product to market.

EnergyAustralia states that deficiencies in the current network pricing arrangements have arisen because the Victorian Government relieved its generators from paying TUOS charges so as to increase their sale value and since then other States have followed a similar policy so that their generators are not disadvantaged. Further, EnergyAustralia argues that with the exception of the existing generators, other code participants are unanimous in their support of locational pricing arrangements for generators. EnergyAustralia also argues that the current arrangements distort

[3] Several of the Victorian Distribution Businesses also included AGL Electricity in its subsequent submission on the draft determination.

customers' decision making regarding fuel alternatives and network bypass because their network charges over-signal the long run costs of network development.

The BCA ERFT considers that NECA's proposal for TUOS to be borne by customers is anti-competitive and will reduce the international competitiveness of downstream industries. It believes that these proposals are in conflict with national competition policy. The BCA ERTF also argues that the proposal is inconsistent with the beneficiaries pay approach to new investments.

Transend Networks Proprietary Limited (Transend) and the Electricity Markets Research Institute (EMRI) argue that the costs of the transmission network should be recovered on a beneficiaries pay approach. Transend believes that this would better signal future costs to users.

Ergon states that it is not clear why MNSPs are exempt from paying TUOS general charges, since they receive the same services and they effectively act as a customer at one end of the interconnector.

*Only customers should pay usage charges*

Stanwell Corporation Limited (Stanwell) supports NECA's proposal that the sunk costs of the transmission network should be recovered from customers, arguing that it promotes economic efficiency and provides appropriate locational signals (since generators already receive locational signals through losses and the risk of capacity constraints).

The NSW Treasury and ElectraNet SA (ElectraNet) consider that sunk costs should continue to be recovered from existing network customers given that NECA's review found that there is no demonstrable material net benefit from changing the current arrangements.

The South Australian Department of Treasury and Finance (SA Treasury) states that existing generators and customers are unlikely to relocate even if there are strong locational signals and that the choice of recovering sunk costs is somewhat arbitrary.

The SA Treasury argues that while customers can install demand side management, embedded generation and other measures to avoid network charges, there are limited options for generators. The SA Treasury is concerned that generators may directly connect to customers to avoid sunk network costs and that this would make the spot market shallower and weaken the NEM.

The Institute of Public Affairs Limited (IPA) argues that while recovering all of the costs of the sunk network from customers is not the optimal solution, there is little to be gained from allocating these costs between generators and customers as these payments are incidental to decisions on the operation and augmentation of network assets.

However, the IPA states that if generators do not pay transmission charges, other than line losses, they will have an incentive to locate closer to fuel sources and that this may be more expensive, on a delivered cost basis, compared to generation that is located closer to a load centre.

The National Generator Forum (NGF) states that because the sunk costs of the network cannot be reversed or avoided, the recovery of these costs should not affect future decisions with respect to asset use. The NGF argues that the recovery of sunk costs from customers leads to an economically efficient outcome because the regulated wires businesses can structure their tariffs using a combination of fixed and variable charges so as to minimises the distortions to network usage.

The NGF believes that generators already contribute to the variable costs of transmission through marginal losses, the risk of being constrained-off without compensation and the risk of creating a new pricing region.

The NGF disagrees with claims that the current arrangements, which exclude network costs from dispatch, disadvantage embedded generators relative to remote generators. The NGF argues that it is appropriate that generators are dispatched on the basis of the marginal costs they impose on network usage and that the full value of marginal costs of the network, other than local congestion, are incorporated by adjusting the regional reference price by marginal losses. The NGF argues that using the network pricing regime to achieve environmental objectives is likely to distort regional spot prices and give economically incorrect signals to market participants. It suggests that these objectives should instead be achieved through a regime that is independent of the NEM.

The NGF criticises the England and Wales tariff based approach, which allocates low TUOS charges to generators and high TUOS charges to distributors in areas where there is excess demand (and vice versa). The NGF argues that while this system may initially indicate where generation should locate, it does not signal the appropriate scale of generation and therefore may lead to excess generation investment in some areas.

Basslink Development Board (BDB) argues that it is appropriate for customers to pay for the sunk costs of the transmission network given that it facilitates the supply of energy to customers. Basslink also argues that customers have a more reliable transmission supply system than generators and as a result they are not as likely to be constrained off with consequential price impacts.

*Neutral position regarding who should pay usage charges*

Powerlink Queensland (Powerlink) is neutral on the issue of who pays TUOS charges, however, it points out that Queensland had a 'generator pays a proportion' regime – based on LRMC to give locational signals - from 1995 to 1997. Powerlink's experience was that the 'generator pays' component was volatile and distortionary each time a new generator entered the grid.

*How would generators recover TUOS charges?*

The SA Treasury states that the only way generators could recover TUOS charges is through the energy price and that this may distort efficient dispatch. Combining this with the fact that customers are likely to bear the costs anyway (either through direct tariffs or increased energy costs), leads the SA Treasury to conclude that there is little reason to levy the costs on generators.

Ergon argues that generators can pass TUOS charges through to customers through either increased average spot market prices or hedging agreements. Ergon states that since new generators will need to take account of network costs in their investment decisions, they will also need to consider them in their pricing and dispatch. Ergon also states that recent International Swap Dealers' Association agreements have included a clause which enables generators (subject to locational TUOS charges in the future) to pass through locational TUOS charges to counterparties.

EnergyAustralia acknowledges that generators may pass TUOS charges through to customers via increased energy prices, however, it argues that the overall pricing outcomes would better reflect market drivers.

Several Vic DBs argue that including TUOS charges in spot market prices will enhance market signals. They also note that while spot market prices may increase as a result of levying TUOS charges on generators, it must be borne in mind that customers will benefit from a corresponding reduction in TUOS charges.

The NGF argues that the likely result of requiring generators to pay for the sunk network would be that the costs would be passed through to customers via higher spot prices. The NGF notes that although generators could pass on the fixed costs as a fixed charge via a contract, market participants could avoid the charges by purchases from the spot market rather than the contract market. The NGF states that the pass through of transmission charges into energy charges would be inconsistent with efforts elsewhere in the transmission pricing review to unbundle electricity pricing to the end consumer in order to avoid uneconomic decisions. The NGF also argues that the recovery of sunk network costs from generators is not theoretically sound and can potentially lead to distortions in generation dispatch, investment/retirement decisions, and locational decisions. The NGF states that it is therefore unclear that there is an equity argument for imposing TUOS charges on generators given that these charges would be passed through to customers anyway and there will be distortions to economic efficiency.

*Competitive neutrality*

Both Bardak Energy Services (Bardak) and the ACF agree with the Federal Government's submission to NECA's review, which stated that the recovery of sunk transmission charges from customers gives an advantage to remotely located coal-fired generation relative to natural gas and renewable generation, which is typically located closer to loads. The ACF also argues that TUOS charges should vary according to location to account for the losses involved in taking power from remote generators.

Several Vic DBs consider that the current and proposed arrangements provide a competitive advantage to incumbent remote generation over new entrants, including those that use much less of the transmission system.

The BCA ERTF considers that the proposed code changes favour existing generators over new generators by implicitly giving existing generators firm access rights to the existing network. The BCA ERTF also considers that it is inappropriate for existing generators to benefit from higher spot market prices set by new entrants that have to internalise transmission costs (resulting for the beneficiaries pay proposal).

Ergon argues that the proposed arrangements give incumbent generators an advantage relative to new generators because they do not pay TUOS charges, whereas new generators are required to pay for the cost of augmenting the network. Ergon argues that economic efficiency would be enhanced by requiring all generators to pay locational TUOS charges since all generators would then be competing on a level playing field and generator bidding would be based on actual costs.

The AGO argues that the code changes do not adequately address the competitive advantage that remote generators have over embedded generators, who make very little if any use of the transmission system.

EnergyAustralia claims that the arrangements distort competition between existing and new entrant (either main system or embedded) generators. To correct this situation, it advocates a locational pricing system for all generators and customers based on the long run costs of network service provision (both existing and future).

*International experience*

Bardak states that there are much lower transmission charges in other countries, which allows them to use simplified ‘point of connection tariffs’ borne by both generators and customers. Bardak urges the Commission to encourage the development of transmission tariffs that are differentiated by voltage level and largely levied on peak demand, rather than energy consumption. Bardak and the BCA ERTF state that international practice is for transmission charges to be allocated between generators and customers on approximately a 50/50 or 40/60 split.

*Operating and maintenance costs*

The AEA argues that operating and maintenance costs are not sunk costs and as such should be borne by beneficiaries, as is the case with other new investments.

*Other issues*

GPU PowerNet (now SPI PowerNet) advocates a nodal pricing system, stating that network utilisation and location should be signalled through the energy market and a secondary market for financial transmission rights. It argues that TUOS charges should be used purely to recover sunk costs and that they should be allocated in the least distortionary manner. SPI PowerNet believes that the recovery of sunk costs should not be used as a means of signalling future investment costs.

The SA Treasury argues that jurisdictions require transition paths to implement reforms in order to gain public support. It argues that the transmission pricing regime must allow for all regions to have appropriate pricing levels and that this is especially important in South Australia where there is a higher investment in transmission assets per capita than in other States.

Most parties support the intention of the changes, that is to make the structure of the TUOS usage charge more LRMC reflective, however, many have concerns associated with the methods used, the process of establishing the price range, the subsequent price, and other issues.

*Complexity*

TransGrid argues that the use of three different pricing methods is unnecessary and will add to the confusion surrounding transmission pricing. Powerlink argues that the three methods of calculating TUOS usage charges increase the information asymmetry and transaction costs to the detriment of customers. Bardak states that a more simplistic method must be established, and EnergyAustralia states that the proposed changes add significant complications to the price setting process with little guidance about how they are to be implemented.

*Volatility*

Powerlink and EMRI state that the introduction of LRMC pricing will result in volatile prices. EnergyAustralia notes that prices need to be stable over time to permit customers to make informed investment decisions.

*Limitation of price signals*

Powerlink argues that the cap on transmission prices, which restricts prices from increasing by no more than two per cent above the regional average, is inconsistent with the purported better signalling that arises from the three methods for calculating TUOS usage charges. The AEA agrees, stating that the two per cent cap should be removed because it is inconsistent with the framework for economically efficient tariffs. Instead, the AEA suggests that TNSPs should be required to disclose to their customers the reasons why tariffs changed by more than two per cent.

*TNSP freedom to choose price*

A number of interested parties express concern regarding the TNSPs' ability to choose the TUOS usage charge from within a range determined by the three methods. Powerlink argues that this approach relies on judgement and may lead to disputes. According to the AEA, the arrangements give TNSPs too much flexibility in setting transmission charges and there is inadequate guidance for the networks to adopt efficient prices from within the cost ranges. The AEA argues that the code should explicitly define the circumstances under which each of the three alternative transmission pricing approaches are to be used. Ergon states that there is no benefit in utilising resources to determine a range of prices when TNSPs will just choose the price that maximises their profits, rather than delivers an efficient outcome.

*Insufficient consideration*

Powerlink, TransGrid, EnergyAustralia, Bardak and the AGO all argue that there has been insufficient consideration of the proposed changes to calculating TUOS usage charges.

Powerlink is concerned that NECA has not undertaken any analysis that demonstrates that the benefits for customers outweigh the costs and disadvantages arising from the complexity of the changed method.

EnergyAustralia argues that there are deficiencies in NECA's analysis because of a failure to conduct quantitative analysis of alternative transmission pricing approaches in determining the net benefits of changing the present pricing arrangements.

Bardak is disappointed that NECA has not considered network pricing arrangements in the gas industry, particularly the United Kingdom's gas industry, which bases transmission charges on LRMC. Bardak also expresses concern that NECA's review demonstrates a lack of understanding of the latest network pricing and trading system design developments in other electricity markets.

TransGrid considers that given the reviews into ancillary services and the integration of the energy market and network services, it is inappropriate to consider the issues raised by NECA's review in isolation from these other issues. However, TransGrid submits that until the effects of price structures that would result from the proposed code changes are known through detailed modelling it is inappropriate for the proposed code changes to be adopted.

*Over-signalling*

Ergon, EnergyAustralia and the SA Treasury all believe that LRMC together with short run pricing signals will not over-signal new investment at constrained parts of the network. Ergon considers that given the current market model does not signal congestion within regions (other than through a spot price rise as a result of a generator being constrained off) there will not be over-signalling from using long run pricing methods. The SA Treasury considers that there may be little overlap between the short run and long run pricing methods because the short run pricing reflects actual transmission constraints at a point in time, whereas long run pricing might only reflect future constraints. EnergyAustralia states that the recovery of market related costs on a short run basis before and after investment, and network costs on a long run basis, does not result in 'double dipping'. It argues that a pricing structure that signals the use of LRMC is appropriate and would not over-signal the costs of augmentation.

SPI PowerNet argues that the correct incentives for the development of load management services and distributed generation will not exist unless loads, as well as generation, have access to price signals based on SRMC. In addition it argues that these short-run price signals can also provide the basis for evaluating long-term investments in the transmission grid. Consequently SPI PowerNet states that TUOS usage charges should not reflect the LRMC of the network but instead provide an equitable recovery of the residual costs of the existing system.

*Regulator involvement*

The AEA states that each TNSP should be required to disclose the method and assumptions used to determine prices at each connection point and that the Commission should be able to review the charges. The NSW Treasury recommends that the code changes should be enhanced by enabling the relevant regulator to have the ability to apply a consistent pricing policy to all eligible parties based on a price from within the cost range. This outcome would exempt TNSPs from the calculation of the price range using the three methods.

*Price range*

EnergyAustralia, TransGrid and the Victorian Energy Networks Corporation (VENCorp) all argue that it is not necessary to establish a price range for all connection points. VENCorp states that this is because the three methods should give similar results in the majority of locations. VENCorp argues it may only be necessary for each TNSP to calculate three prices at a limited number of locations. With experience, the most appropriate method for a particular network would be established and the requirement for the three calculations removed.

EnergyAustralia considers that the utilisation adjusted CRNP is the most appropriate pricing method, and together with suitable negotiation guidelines to cover the few instances where the standard pricing approach might deliver inappropriate outcomes, will be a more efficient approach than the 'pricing smorgasbord' proposed.

*LRMC method*

EnergyAustralia argues that the use of LRMC pricing as set out in schedule 6.4 of the code is incapable of distinguishing between individual customer connection points and therefore is not generally practical for the relatively large number of interdependent load connections to a transmission network. It is only practical when considering transmission development costs on a regional or large area basis. EnergyAustralia further argues that considering only the development costs contained in the annual planning review (which covers 10 years) in the calculation of the direct LRMC will significantly undervalue the use of the network. EnergyAustralia contends that traditionally a period commensurate with the life of the assets and lengthy enough for associated net present value calculations has been, and should continue to be, used for tariff calculations. EnergyAustralia states that a period of 25 years is appropriate.

Transend is also critical of the LRMC guidelines, suggesting that rather than expressing LRMC in per unit terms, it should be expressed as a $ per annum amount. It argues that this would relate directly to LRMC. Transend also criticises the specification of the direct LRMC in schedule 6.4 saying that it results in the same nodal cost across the network for each node deemed to be served by a particular. This, it argues, leads to a less than intuitive result, whereby nodal prices differ due to different baskets of augmentations deemed by the TNSP to benefit each node.

TransGrid argues that the LRMC method, which is based on projected augmentations in a five year planning period, can result in large prices. In support of this concern, TransGrid presents modelling data illustrating the results of applying the method to their present five-year plan. Charges in the Lismore area, where much of the projected augmentation in the next five years would be located, would be about ten times the State average. TransGrid states that this is because the capital invested in the five year period will serve considerably more load growth than that occurring during this time and the works program may be driven by factors other than load growth.[4]

### 4.2.2 What the applicant says

NECA states that economic efficiency is the best approach for resolving the issue of who should pay for the existing transmission network and that the overriding objective should be to encourage optimal utilisation of the network. Economic theory suggests that the most efficient approach is to charge marginal cost prices for use of the existing system and to recover the residual costs through a lump sum that does not distort the prevailing locational and congestion signals.

NECA acknowledges that, with the exception of connection charges, generators do not pay a direct share of the existing transmission network. However, NECA argues that generators indirectly contribute to the cost of the transmission system because they pay marginal losses, which are greater than average losses, with the difference rebated to customers to reduce their network charges. It argues that the current arrangements of charging generators short run marginal cost and recovering the remaining costs from customers is sound in terms of economic theory and is no more distortionary than the alternatives.

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[4] Submission from TransGrid ‘Application of NECA Pricing Recommendations in NSW’.

NECA claims that the alternative of charging for the existing system on a beneficiaries pay approach would not impact on the locational signals or utilisation of the network, however it would produce distortions in the energy market. NECA states that large customers would be disadvantaged if generators recouped transmission charges through a $/MWh charge. However, smaller customers, including households, would be disadvantaged if generators recouped the charges on a $/MW basis. Further, NECA argues that all customers would lose if a $/MW charge had an adverse effect on the market's ability to cope with peak demand.

NECA's review investigated the network pricing arrangements in several other countries and in its final report NECA concludes that there is no consistent approach in these markets. This is partly a result of differences in market design, but more a result of the fact that there is no clear approach that delivers ideal pricing signals.

NECA concludes that there would be 'no demonstrable material improvement from changing those arrangements' and that 'transmission use of system charges should, therefore, continue to be recouped as now from network customers'.

NECA includes maintenance costs in with the sunk costs of the network because it argues that they are effectively unavoidable except at the margin.

NECA's review concludes that the current method for calculating TUOS charges is not theoretically robust and that marginal cost pricing principles require prices to signal new investment costs. NECA argues that the proposed code changes aim to ensure that TUOS usage charges reflect the LRMC of the transmission network, thereby promoting efficient utilisation of present and future transmission capacity.

In addition, NECA's review concludes that the CRNP method should be revised so that:

- prices reflect spare capacity;
- costs of system wide reliability and security are not allocated to individual customer groups;
- prices minimise bypass; and
- the merits of price stability are taken into account.

NECA identifies the following difficulties associated with establishing a price that reflects the LRMC of transmission use:

- direct calculation of the LRMC is highly dependent on assumptions of future load growth and use; and
- mechanistic approaches such as the CRNP rely on implicit assumptions and may only reflect the true LRMC under certain conditions.

NECA believes that it is appropriate to use alternative approaches to define an LRMC price range for each location, and allow the TNSPs discretion in specifying the price within this range, based on their knowledge of the network.

NECA anticipates that the utilisation adjusted CRNP will generally give appropriate outcomes and that the existing CRNP method will not be used for price setting and ultimately may not be calculated as part of the range. NECA further suggests that if a particular TNSP considers that one of the methods appropriately reflects the LRMC prices then they would have the ability to set all prices on this basis.

NECA argues that providing TNSPs greater flexibility in choosing the TUOS usage charge will lead to a price that more closely reflects the future transmission costs resulting from the use of that connection point.

### 4.2.3 ABARE's submission to NECA's review

In a submission to NECA's review, the Australian Bureau of Agricultural and Resource Economics (ABARE) acknowledges that it is difficult to design a pricing regime that allocates existing capacity efficiently and also provides the correct incentives to expand the network.

ABARE contends that while the existing network pricing arrangements provide some price signals for the location of new generation and load, these arrangements are likely to distort network use and long run investment decisions for the following reasons:

- the NEM model averages marginal transmission losses and total distribution losses, therefore network users do not see clear signals about the extent and timing of losses and do not have incentives to minimise losses through locational and load adjustment; and

- TUOS charges are allocated on a postage stamp basis rather than being fully cost reflective.

### 4.2.4 Issues arising from the draft determination

The draft determination imposed the following conditions of authorisation:

**C4.1 Chapter 6 of the code must be amended to incorporate the following principles for transmission usage pricing:**

1. **The objective for transmission usage prices is to promote efficient utilisation of all transmission networks within the NEM.**

2. **Transmission usage prices must be universal and symmetric; they must send equivalent signals to all transmission users and must be designed to recover equivalent net revenues from injections and offtakes.**

3. **Transmission usage prices must reflect the level and location of congestion, at the time usage occurs.**

4. **When congestion is at levels where the code indicates relief measures should be considered, components of the transmission usage prices that relate to the relevant part of the network should reach values that**

**promote efficient decisions between network-related measures and market based alternatives.**

5. **Transmission usage prices at a particular location and time should reflect the likely impact that an increase in the local offtake would have on network congestion.**

6. **Transmission usage prices must take into account other transmission usage signals present in the market.**

7. **A single preferred pricing method should be adopted consistently across the market except where positive benefits from departing from it can be clearly demonstrated to the regulator.**

8. **The single preferred pricing method must be practicable and cost effective to implement.**

**C4.2 The code must be amended to require NECA to develop, model and test a default pricing method that satisfies the principles listed in C4.1. The pricing method must also establish how revenue collected through the application of transmission usage prices is to be apportioned amongst providers of prescribed transmission services. In developing this pricing method NECA must follow the code consultation processes. The pricing method must be publicly available within 12 months of the ACCC's authorisation of the network pricing and MNSP code changes taking effect.**

**C4.3 The code must be amended to require the National Electricity Market Management Company Limited (NEMMCO), by 31 March each year, to compute and publish TUOS usage prices for the coming financial year, and the apportionment of the revenue collected, in accordance with the methods developed by NECA according to C4.2. TUOS usage prices determined in accordance with C4.2 must not apply to generators and MNSPs until 1 January 2003.**

**C4.4 The code must be amended to require TNSPs to adopt the published prices unless they can clearly demonstrate to the regulator that there is a net benefit to the market from doing otherwise.**

**C4.5 The code must be amended to allow network users to request firm transmission usage prices to apply over periods of up to five years. The TNSP must base these on the best available estimates of projected trends in the annual transmission usage prices.**

**C4.6 The code must be amended so that clause 6.5.5 ceases to have effect after 31 December 2002.**

The AEA supports the general thrust of the ACCC's proposed approach but is concerned that a distant generator would pay considerably lower costs after an augmentation as the usage charge would then reduce. It is also concerned that the list of principles for transmission usage pricing did not include the principle that beneficiaries should pay.

The AGO supports the principles underlying the Commission's conditions (C4.1 to C4.6) but queries whether a TNSP would have an incentive to overstate its costs in the material it submitted for the central pricing calculations. The AGO also considers it essential that the methodology for calculating TUOS charges be codified prior to authorisation in order for it to be enforceable.

Basslink Proprietary Limited (BPL) considers that the proposed usage charges and rebates for MNSPs would bring additional uncertainty for developers and come at a time when the NEM is already providing inadequate incentives for investors. BPL is concerned that charges for generators and MNSPs are being introduced while related issues, such as network property rights, are still unresolved. BPL argues that capacity based charges might result in increased peak energy prices and greater spot price volatility. It is concerned that there is a lack of clarity as to how existing signals would be taken into account. It is also concerned that the proposal for a five year fixed price option would be difficult to specify and apply.

The National Electricity Distributors Forum (NEDF)[5] believes the Commission's transmission pricing proposal might be developed to provide a more efficient basis for allocating network costs than the present arrangements. However the NEDF considers that, like NECA's LRMC proposal, it may suffer from subjectivity relating to load, generation and network planning scenarios. The NEDF considers that only the allocation of a component of transmission infrastructure costs to existing transmission-connected generators would create a level playing field for generators. The NEDF supports a uniform approach to pricing but queries the need for NEMMCO to be involved since all the data and knowledge resides within the NSPs and its transfer to NEMMCO would be inefficient. The NEDF stresses the need to finalise the transmission pricing arrangements rapidly.

ENERGEX Limited (ENERGEX) agrees that it is desirable to have a uniform and consistent approach to pricing but queries the desirability of separating the process from the relevant TNSPs. ENERGEX notes that at present transmission locational signals are delivered through two quite separate routes: the energy market and TUOS pass-through by distributors. The result may be a loss of clarity of signals. ENERGEX suggests that more thought should be given to either having retailers pay TUOS directly or incorporating some component of TUOS in the energy market (via generator TUOS charges).

Enertrade considers that the Commission's proposal of pricing symmetry across industry sectors is inequitable given that generators and customers do not receive symmetric levels of network service. A corollary is that the establishment of some form of property right should be incorporated into the Commission's principles, although Enertrade acknowledges this would be a major task to implement. Enertrade

5 The National Electricity Distributors Forum comprises the following member organisations: ActewAGL; Advance Energy; AGL Electricity; Aurora Energy; Australian Inland Energy; CitiPower; ENERGEX, EnergyAustralia; Ergon Energy Corp. Ltd; ETSA Utilities; Great Southern Energy; Integral Energy; NorthPower (now known as Country Energy); Powercor; TXU; United Energy; and Western Power Corporation.

is also concerned that the Commission's proposals would result in transmission prices rising in advance of any shortage of capacity.

Hazelwood Power (Hazelwood) anticipates that NECA's review of the integration of energy markets and network services (RIEMNS review) will shortly yield proposals for stronger locational signals in the energy market. It therefore considers that there is little value in investing NECA's time in developing the proposed transmission usage pricing system set out in the draft determination when a workable approximation to full nodal pricing is imminent. Hazelwood also stresses the need to expedite the development of network property rights in order to provide a basis for generators to manage access risks. At present, proposals for generators to pay network charges are asymmetric, given that generators face constrained-off risks while customers are entitled to reliable supply. Hazelwood questions the practicality of establishing property rights in conjunction with the Commission's proposed pricing regime.

Hydro Tasmania (Hydro) notes that benefits should flow from greater interconnection through increased competition between suppliers and greater ability to exploit the complementarities of different electricity production methods. It submitted a report by Professor Grant Read that argues that the 'adjusted CRNP' method included as an appendix to the draft determination could inefficiently inhibit long distance trade and would face significant implementation difficulties. Hydro also considers that the ongoing regulatory uncertainty regarding network pricing has the potential to impact adversely on the process of Tasmania joining the NEM.

Intergen considers that locational signalling within the NEM is already adequate, though not always price-based. Non-price locational signals observed by generators included the risk of being constrained on or off, the risk of new regions being created and exposure to changes in loss factors.

The Newcastle Group considers that the Commission's approach effectively forces users to pay for investments that may never occur. It argues that it is difficult to understand, involves arbitrary assumptions and could lead to severe volatility in prices. It argues that non-price signals, such as from the risk of being constrained off and signals from the regulatory test, might actually be clearer and more predictable.

Loy Yang Power (Loy Yang) questions whether the proposed conditions of authorisation would increase the public benefit or decrease the anti-competitive detriment of the original NECA proposal. It argues the Commission's proposal would not be symmetric in relation to costs and service levels and would be arbitrary in the application of prices and allocation of revenue. There would be continued delay and uncertainty, which would undermine investor confidence. It recommends that the transmission pricing principles should be amended to include the beneficiaries-pay principle and principles in relation to property rights.

The NGF supports a number of the pricing principles proposed by the Commission, namely that the objective should be efficient utilisation, that usage charges should relate to actual congestion, that over-signalling should be avoided and that pricing should promote efficient decisions as to how to relieve congestion when it arises. However, it considers that the principle requiring equal recovery from injections and offtakes had no economic basis and was inequitable given that generators do not receive an equivalent service level to customers.  The NGF has concerns with the proposal to base a pricing methodology on a modified form of CRNP, arguing it would combine all the practical and workability problems that it was supposed to avoid and would not ensure efficient choices between network-related and market-based measures to relieve congestion.  Depending on how it was implemented it might significantly distort dispatch and lead to inefficient utilisation of the existing network.  It could lead to substantial windfall gains and losses and increased pricing volatility without providing any mechanism which enables market participants to contract for transmission pricing or service quality.

The NGF submitted a report by Morrison and Co, which outlines an alternative approach based on an extension of the current approach to setting marginal loss factors (MLFs).  It would involve modelling the costs of network congestion for a range of historical and projected scenarios so as to derive a set of price differentials that appropriately reflected the expected marginal costs of both losses and congestion.

The NGF recommends that the principles in condition C4.1 of the draft determination should be extended to include the establishment of a property rights regime.  It also suggests that the ACCC should request NECA to consult and report back on the options for establishing property rights, and to review the beneficiaries pay approach specifically addressing the ACCC's concerns.  Given the proposed review of the beneficiaries pay approach and progress of the RIEMNS review, the ACCC should withdraw condition C4.2 and associated conditions.

NECA considers that further clarification is needed on a number of issues before further development work could be sensibly undertaken.  These include:

- whether the usage charge should be based on short or long-run marginal costs or new investment costs;
- what share of revenue the usage charge should represent;
- how the usage charge should be allocated between generators and customers;
- the acceptable degree of volatility;
- whether the usage charge should be forward or backward looking;
- how to move from cost allocation to prices;
- the basis for zones;
- the role of NEMMCO;
- the basis for five year prices; and
- how to reconcile reasonable use of discretion with a single national regime.

NECA is also concerned that the proposed implementation timetable is insufficient and suggests this would require the pricing methodology that was developed to sit outside the code.

NECA also submitted a worked example of the indicative pricing method, which raises questions about the adequacy of that method.  NECA argues that there are several areas that require further work, such as:

- the identification of future augmentation costs;
- the netting off of existing signals;
- the prospect of volatility and the dissipation of signals following augmentation;
- the use of CRNP methodology and backward-looking data; and
- issues of equity between customers and generators.

NECA advocates a holistic way forward on network pricing and related issues.  This would include a suite of measures to improve price signals in the energy market, moving towards firmer access to the transmission network and a refined approach to allocating the costs of new regulated investments.

NEMMCO comments that while it did not seek the role proposed for it in relation to transmission usage pricing, it understood the rationale for the appointment of a body independent of the TNSPs to calculate and administer TUOS prices on a consistent national basis.  It stresses that the methodology should be codified to the maximum extent possible, leaving little discretion in regard to input assumptions.  NEMMCO notes that a modest increase in the number of pricing regions in the NEM could improve locational price signals in the spot market and might significantly reduce the need to enhance locational signals through TUOS pricing.  However, NEMMCO also notes that other factors, such as the availability of hedging instruments and market power issues, would need to be taken into account when considering more regions.

NRG Flinders supports the NGF's submission.  It argues that generators already face adequate price signals and that the universal pricing scheme proposed by the Commission could create perverse outcomes such as discouraging generation investment at Port Augusta and providing disincentives to remote 'green' generation such as wind or hydro. NRG Flinders cannot find a justifiable reason to reject the beneficiaries pay proposals in totality.  It notes the continuing uncertainty as to the allocation of transmission charges and advocates a holistic approach, under which the network pricing proposals would be looked at in conjunction with the current proposals under NECA's RIEMNS.

The NSW MIG considers that the Commission's proposed pricing regime could lead to pricing volatility and uncertainty.  It argues that the proposal to calculate TUOS charges and rebates annually on the basis of utilisation levels and load flow modelling appears to be an attempt to implement an administered form of nodal pricing that was unnecessary, complex and unlikely to produce a public benefit.

Origin Energy (Origin) supports the Commission's proposal that usage charges be applied to all users depending on whether they add to or relieve congestion.  However, it considers that the methodology needs to be clarified and codified to give investors confidence in the basis of charges into the future.  It argues that the proposed option for five-year fixed charges does not match well with the requirements of new generation projects for cost certainty over ten to fifteen years.

Powerlink argues that some of the Commission's proposed pricing principles, such as the requirements for universality and symmetry, the relationship to congestion and the need to take other transmission signals into account, are a move away from principles already included in the code. It argues that this represents a policy change rather than a code refinement, and should therefore be endorsed by the participating jurisdictions and subject to wide consultation. Powerlink considers that neither NECA's nor the Commission's proposals are robust, objective and practicable. It argues that both involve the exercise of a significant degree of judgement and would fail to provide pricing stability.

Queensland Treasury (QLD Treasury) submits that the Commission's proposals would fundamentally change the NEM design and have not been subject to rigorous consultation. It believes that the usage prices should behave in a manner akin to nodal pricing whereas NECA, through the RIEMNS report, has rejected the adoption of nodal pricing in the NEM. Accordingly, it suggests the words 'at the time usage occurs' and 'at a particular time and location' be removed from principles C4.1.3 and 4.1.5 respectively. QLD Treasury is concerned that the proposed timeframe for the development of the pricing methodology is inadequate and argues that the outcomes should be embodied in code changes.

SA Treasury strongly requests that the Commission undertake modelling to demonstrate the practical implications of the network pricing determination, including the implications for distribution pricing. It is concerned with the potential for volatility and expresses interest in NECA's view that a refined regional structure would capture most of the benefits of full nodal pricing and allow a simpler and more practical network pricing regime. SA Treasury encourages the Commission and NECA to work together on a revised and practical network pricing package for consideration by interested parties.

Snowy Hydro Trading Proprietary Limited (Snowy) considers the Commission's usage pricing proposal might be workable if a robust methodology could be developed that did not significantly distort dispatch and was driven by market based incentives. However, Snowy stresses the need to consider network pricing in the context of a consistent and integrated perspective of the current and future NEM design.

Stanwell supports the position taken by the NGF and the Newcastle Group. It argues that generators are already exposed to adequate locational signals through MLFs and volume constraints. It is concerned that the proposed generator usage charges could distort dispatch and that the ongoing uncertainty had the potential to significantly reduce liquidity in the contract market.

Tarong Energy (Tarong) believes that the price signals already contained within the energy market design deliver all the requirements the Commission considers need to be addressed by the proposed TUOS usage charge. It agrees with seven of the pricing principles proposed by the Commission but disagrees with the requirement that the prices be universal and symmetric and recover equal revenues from injections and offtakes. Tarong argues that the physical power system does not require such symmetry and that in any case the access rights of generators and customers are not symmetric.

The Tasmanian Department of Treasury and Finance (Tas Treasury) agrees with the Commission's proposed pricing principle that required other pricing signals to be taken into account but queries whether it is practicable to implement. It is concerned that the indicative methodology in the appendix, being based on an arbitrary usage algorithm as a surrogate for impending congestion, risks allocating sunk costs to participants such as MNSPs who should not face such an allocation and might result in inappropriate variability from year to year. Tas Treasury notes the potential adverse impact of the proposals for BPL and Tasmania's energy reform initiatives.

At the pre-determination conference Transend suggested an additional pricing principle: the usage price should reflect the level of reliability of supply. Transend also indicated that the modified CRNP method was currently in use in Tasmania. Transend stressed the need to ensure that utilisation is measured as a proportion of the useable capacity of the asset, taking credible contingencies into account.

TransEnergie Australia Proprietary Limited (TransEnergie) supports the position that where entrepreneurial interconnections add to network congestion they should incur a network charge and that where they relieve congestion they should receive a rebate. However this was only on the condition that network charges are determined by a central authority, as proposed in the draft determination. It argues that network users that receive a high level of network service should pay more than those users that receive a lower level of service.

TransGrid notes that two sets of usage pricing principles were included in the draft determination: seven 'evaluation principles', used to evaluate NECA's methodologies and eight 'authorisation principles' listed in condition C4.1. TransGrid broadly supports the evaluation principles but recommends substituting 'utilisation' for 'congestion', given the need for price signals that are a leading indicator of future congestion. It queries the need for new congestion-based signals, because inter-regional congestion is already adequately signalled and any significant intra-regional pricing becomes inter-regional as new pricing regions are introduced. TransGrid queries the appropriateness of principle 1 in condition C4.1, which states the objective should be to promote efficient utilisation of all transmission networks within the NEM. TransGrid cannot see any public benefit arguments that justify the requirement to recover equivalent net revenue from injections and offtakes. It believes this requirement would create unnecessary volatility.

TransGrid recommends that the pricing methodology should be included in the code, in order to limit the discretion of those applying it: the pricing principles alone would not be sufficient. It accepts that, given the methodology would be applied on a market-wide basis, there is a possible role for a national body to apply and administer it. While it might be appropriate for NEMMCO to undertake that role, alternative bodies such as the Inter-regional planning Committee (IRPC) or a coordinating committee of TNSPs could also do this, and might be more appropriate if the pricing methodology related to network planning.

TransGrid acknowledges the need to offer customers long term certainty in network charges where they require it.  However, it argues that the Commission's proposal for TNSPs to offer five year firm prices does not address how the resultant risk is to be managed.  TransGrid argues that since the Commission's proposals for universal, symmetric charges creates the possibility of mutual hedging between generators and customers, the requirement on TNSPs to offer firm five year prices should be withdrawn.

VAW Kurri Kurri Proprietary Limited (VAW) is concerned that a usage price expressed in dollars per MWh that is fair to most users might be excessive for a large, electricity-intensive user.  It also stresses the need for large users to be able to negotiate long-term firm prices.

Several Vic DBs agree that congestion based pricing may provide signals that should encourage demand side response and non-network solutions but they are concerned that the approach needs to take account of practical constraints.  To the extent that political or technological constraints limit the ability of end consumers to respond to congestion-based transmission prices, there is reason to question whether its implementation in the near term is sound public policy.  This deserves further careful consideration by the regulators and the participating jurisdictions.

Western Power recommends that the Commission retain the CRNP method as the basis for calculating TUOS usage prices.  Western Power notes that the method is objective and its anti-congestion bias has not been significant in WA, where most of the network is mature and well loaded. Also reliability of supply tends to be inversely correlated with level of utilisation and so it may be appropriate for prices to be high where utilisation (of multiple supply lines) is low.  Remedies that could be applied in any remaining isolated instances could include applying an economic value test, imposing a price ceiling or prices could be averaged over a number of connection points.  In any case new augmentations must be planned ten years or more ahead, so the value of congestion-related signals is questionable and subjective.

Western Power notes it has been allocating 20% of costs of the shared network to generators using CRNP methodology.  Western Power considers these provide useful locational signals to generators, but notes that they do not adequately signal the adverse stability impacts of generators that locate at network extremes.  It is concerned that stability impacts and supply reliability impacts would not be correctly reflected by the indicative pricing method presented in the appendix to the draft determination.  Western Power agrees that usage charges should be recalculated annually, and argues that the offering of longer-term firm prices should be at the TNSP's discretion, with any resultant under or over recovery being treated as non-regulated revenue.

### 4.2.5 Commission's considerations

The Commission considers all network users should be exposed to price signals that promote efficient utilisation of existing network facilities, efficient investment in transmission networks or alternatives and the efficient location of new generation, load or MNSPs.  These signals should be market based and the best way to achieve that is likely to be through the closer integration of locational signals into the energy markets.

However, under the proposed code changes usage signals are delivered through a variety of routes, decreasing the overall effectiveness of the proposals. Under NECA's proposed code changes, all network users would see some price signals in the energy market (through losses, inter-regional constraints and the risk of new regions being created). Generators and customers would also see price signals through the requirement to contribute to the cost of new investments where they are deemed to be beneficiaries of that investment. Generators and MNSPs would receive further price signals through the risk of intra-regional constraints and the negotiated TUOS charges. Customers would also receive price signals through TUOS usage charges.

In its draft determination, the Commission concludes that the signals to generators and MNSPs under NECA's proposed code changes will be inadequate, especially given the Commission considers that the proposed beneficiaries pays arrangements for new investments are not workable in their current form.

In response to the draft determination, the majority of interested parties submitted that the beneficiaries pays arrangements have significant merits and should be further developed rather than abolished altogether. As detailed in section 6.2 of this determination, the Commission accepts this view and has imposed a condition of authorisation requiring NECA to further investigate the details and implementation arrangements for allocating the cost of new investments to all network users.

While the allocation of some new investment costs to generators and MNSPs should provide them with locational signals, the Commission is concerned that there is still a need to improve the signalling in the energy market. For example, intra-regional losses are calculated using a static loss factor that will not necessarily reflect the conditions prevailing at critical times. For this reason, generators are not charged according to the true utilisation cost (usage) they impose on the network, especially in peak periods. The Commission considers that the appropriateness of the loss factor will depend on the size and location of the generator and their actions during peak periods. However, for many generators the loss factors they see will be too low, most of the time, although some participants may be more exposed, eg Stanwell claims it pays over $100m annually in losses.

The Commission is also concerned that intra-regional transmission congestion is not priced in the spot market, although the Commission acknowledges that generators do see some signals from the forgone revenue as a result of not being dispatched due to a constraint.

While sustained congestion of more than fifty hours per year can trigger a new region, the Commission notes that these provisions are yet to be fully tested. Jurisdictional derogations apply in most jurisdictions, and there is resistance from some jurisdictions and market participants to changing the current regional boundaries.

The NGF and a number of individual generators point out that constrained-off generators experience locational signals through volume constraints. Nevertheless those generators are paid more than the local marginal price for any energy they actually generate, which can partly counteract the signals delivered through the volume constraints, and customers within the constrained area must pay that same high price.

Conversely, constrained-on generators receive a low price in the spot market and nearby customers are able to purchase at the same low price.

Overall, the Commission notes that locational signals in the spot market can sometimes be inadequate for generators, customers and MNSPs under the present arrangements.

Further as the contract markets trade instruments that reference spot prices, any spot market deficiencies are likely to affect the contract markets, compromising their ability to recruit cost-effective alternatives to network augmentation.

NECA has indicated its intention to bring forward code changes arising from RIEMNS that will:

- improve risk management through the extension of, and refinements to, the settlement residue auction arrangements;
- move towards firmer access to the transmission network; and
- improve the treatment of transmission and distribution losses.

The Commission welcomes this development and considers that it will go part way towards addressing the concerns above.

However, the broader question of changes to the current regional structure of the NEM is one that needs to be addressed. The Commission therefore encourages governments and other stakeholders to examine the prospects for further enhancing locational signals in the spot market and for developing effective and comprehensive network property rights.

Without such changes, the Commission considers that the locational and investment signals to which remote generators and MNSPs are exposed are likely to be deficient. If this situation persists, it risks jeopardising the efficient evolution of the electricity supply industry. In particular, it may inappropriately inhibit the development of local generation and demand side solutions to the detriment of electricity consumers.

In its draft determination the Commission sought to rectify the deficiency in signalling by imposing conditions of authorisation requiring NECA to develop a new method of transmission usage charges and rebates that was applicable to all network users depending on whether they add to or relieve network congestion.

Several responses to the draft determination do not support the Commission's proposal. Further a number of parties comment that NECA's RIEMNS process is considering market-based alternatives that involved strengthening the locational signals present in the energy market and the RIEMNS proposals could render the Commission's proposal superfluous.

The Commission accepts that these are valid concerns and has therefore decided to withdraw its proposed conditions requiring the development of a universal transmission usage pricing regime.

***Structure of usage charges***

The Commission agrees with NECA's view that the current transmission network pricing method is inadequate and a more effective method is required. To provide a basis for assessing whether the proposed code changes deliver public benefits, the Commission has developed a list of attributes for transmission usage prices. Transmission usage prices developed with these attributes will promote efficient utilisation of the network, investment in cost-effective alternatives to network augmentations and efficient location of new generation, loads and market network services.

*Attributes of effective transmission usage price signals*

- *Forward-looking*. Prices should reward changes to participants' behaviour that result in more efficient market outcomes. Prices should therefore reflect future, avoidable costs rather than past, sunk costs. Typically such avoidable costs will include the costs of rationing limited network resources, the costs of transmission losses and the costs of augmenting the network. Prices should also reflect the impact that a change in the participant's behaviour will have on avoidable costs. Thus when and where a reduction in consumption, or increase in output, is likely to avoid costs, it should be encouraged. Conversely, where a change in behaviour would have no material impact on costs it should attract neither reward nor penalty.

- *Utilisation-related*. Prices should normally correlate with transmission utilisation on the basis that the level of utilisation is generally a good predictor of the need for augmentation or rationing of resources. Prices should therefore increase as utilisation increases and be low when there is little likelihood that rationing or augmentation will be necessary during the period for which the prices are determined.

- *Universal applicability.* Prices should directly reward or penalise all market participants when and where their behaviour affects avoidable transmission costs. Thus generation, load and market network services should be equally rewarded if they reduce the likelihood of congestion or equally penalised if they exacerbate congestion. The signals should be applied consistently right across the market.

- *Timeliness*. Usage prices should be updated in a timely fashion to reflect evolving system conditions. On the other hand, those who require long-term price certainty should have the opportunity to obtain it on terms that reflect the projected trajectory of future usage prices.

- *Capped according to the cost of augmenting the network*. When utilisation is at levels where the code indicates relief measures should be considered, components of the transmission usage prices that relate to the relevant part of the network should reach values that promote efficient decisions between network-related measures and alternatives.

- *Consistent with other aspects of the NEM.* The NEM design provides some transmission usage signals through the energy market. Negotiated use of system charges also provide some transmission signals. Unless transmission usage prices take these other signals into account, there is a risk of over-signalling.

- *Practicable and cost-effective.* The procedures for deriving transmission usage prices should be robust and straightforward to administer. Transaction costs should not be significant.

- *Objective and transparent*. Participants should have access to sufficient information to satisfy themselves that pricing procedures have been correctly applied and to undertake scenario-based calculations of future usage price trends. A corollary is that the procedures should not involve subjective judgement.

Prof Grant Read[6] argues that utilisation-related pricing may inefficiently inhibit long-distance trade. The Commission agrees that pricing signals that do not fully reflect short run cost fluctuations may not promote completely efficient outcomes. The theoretical ideal could be to have fully adequate locational signals in the spot market supplemented by tradeable transmission rights. However, longer-term signals (eg, time of use signals revised annually) can still be better than none at all, and if suitably structured may help promote more efficient, albeit not perfectly efficient, outcomes. Utilisation-related signals are likely to be superior in that regard to those that take no account of the degree of utilisation.

The Commission considers that where a TUOS usage pricing method can be demonstrated to possess the above attributes, at least to some extent, the outcomes are likely to be more efficient and will result in a greater public benefit than otherwise.

The following sections discuss whether the proposed three methods of calculating TUOS usage prices have the above attributes.

*Method 1: Standard CRNP*

The standard CRNP method allocates fifty per cent of the costs of existing assets to customers using a procedure that was originally developed to determine fault currents in the transmission network under different contingencies. Essentially, CRNP allocates asset costs to customers that are downstream of, and electrically close to, the relevant assets.

*Forward looking*: The standard CRNP method is not inherently forward looking. It is based on the sunk costs of existing assets, rather than future, avoidable costs. It allocates costs according to a technical usage criterion that only loosely relates to economics and hence the allocation to a participant may not truly reflect the impact of that participant's activities on avoidable costs. For example, a customer may be relieved of the bulk of network charges if there is a nearby generator, even if that generator is high cost and rarely runs at full output. Conversely, the costs of major assets may tend to be allocated to nearby users even though the assets provide system-wide benefits.

*Utilisation related*: The standard CRNP method is not utilisation-related and in fact may deliver perverse outcomes, such as high charges for assets that have a low utilisation level and low charges for assets with a high utilisation level.

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6 Paper by Prof Grant Read – A Critique of the ACCC proposal on Transmission Pricing, 22 March 2001.

*Universally applicable*:  The standard CRNP method, in the form proposed, is not universally applicable since it only produces prices for loads and does not provide direct signals for generators and MNSPs.  Consistent signals across the NEM may not result because the method is applied separately to individual regions or TNSP areas. Although costs may be allocated outside the region, they appear in the general charges rather than usage charges, thus failing to pass signals through to network users.  As a result, the method does not indicate the relative advantages or disadvantages of locating in different areas.  In comparison, the present code provisions permit, although do not require, consistent usage pricing over multiple regions.

*Timeliness*:  The cost allocation is to be performed at the start of each five-year regulatory control period and hence the price signals could be inappropriate by the end of the five-year period, due to evolving system conditions.  Unless the price signals are adjusted regularly in the light of participant responses, they may stimulate excessive reactions, a risk noted by the NGF in relation to the England and Wales arrangements.

*Capped according to the cost of augmenting the network*:  The method may not produce charges that are below the incremental cost of augmentation.

*Consistent with other aspects of the NEM*:  The standard CRNP method does not take into account the SRMC signals (ie. losses and constraints) already present in the spot market.  Rather, the code changes would require the settlements residues that accrue from losses and constraints to be deducted from the TUOS general charge.  As a result, there may be some over-signalling of congestion by having a TUOS usage charge that is intended to reflect LRMC but does not take into account the SRMC signals already present in the spot market.  This is in contrast to the present situation, where interregional residues must be deducted from the relevant assets' revenue requirements before applying the CRNP method.

*Practicable and cost effective*:  Computer programs already exist which can apply the method at reasonable cost.

*Objective and transparent*:  The standard CRNP method is based on selected operating conditions experienced during the previous financial year.  The selection process is somewhat subjective and may prove to be a source of contention and dispute.  It also makes it difficult for participants to conduct their own scenario-based analyses to predict future usage price trends.

Therefore, evaluating the standard CRNP method against the attributes of efficient TUOS usage charges listed above indicates that it does not meet most of the criteria.

*Method 2: Modified CRNP*

Under the modified CRNP method the full annual costs attributed to heavily utilised assets would be allocated, whereas costs of under-utilised assets would be discounted by up to one hundred per cent before applying the CRNP analysis.  The modified CRNP method allocates the costs of existing assets, rather than the costs of relieving congestion through augmentation.

*Forward looking*: TUOS usage charges calculated using this approach will not be truly forward-looking, except in circumstances where the cost of an existing asset happens to be a good predictor of the cost of augmentation. As with the standard CRNP method, the proportion of costs allocated to an individual user will not necessarily reflect that user's impact on avoidable costs.

*Utilisation related*: The modified CRNP method overcomes the criticism that standard CRNP charges are not utilisation-related.

*Practicable and cost effective:* The Commission understands that the method is currently being applied in Tasmania, but is as yet unproven in relation to the mainland networks. The algorithm is not very different from that of standard CRNP and the Commission anticipates that computer programs for standard CRNP could be adapted at reasonable cost.

The modified CRNP method is assessed equivalently to the CRNP method against the remaining attributes.

The Commission considers that the modified CRNP is a better method than the standard CRNP but notes it is based on a somewhat arbitrary cost versus utilisation relationship. The Commission notes TransGrid's criticism regarding the practicality of implementing this approach but even taking this into account the Commission considers the modified CRNP method will be an improvement over the standard CRNP method, if it is readily implemented.

*Method 3: Direct estimation of LRMC*

The code changes include a LRMC method based on proposed augmentations contained in TNSPs' annual planning documents and the underlying assumptions regarding load growth and generation development. The LRMC method may be implemented by allocating the present value of the augmentation costs to individual load connection points on the basis of the incidence of benefits and the projected load increments at the connection points.

*Forward looking/Utilisation related*: The LRMC method is utilisation-related and forward-looking in that it attempts to identify areas where congestion is likely to arise and allocates the costs of relieving that congestion rather than the costs of existing assets.

*Universal applicability*: The prices would apply only to loads and there would be no assurance of pricing consistency across the NEM.

*Timeliness:* It is not clear that prices would still be relevant towards the end of their five year currency period.

*Capped according to the cost of augmenting the network:* The method is designed to reflect augmentation costs appropriately.

*Consistent with other aspects of the NEM*: The LRMC method does not take account of existing signals provided through the spot market.

*Practicable and cost effective/Objective and transparent*: The outcomes of the LRMC method will be strongly influenced by the planning horizon considered as well as assumptions about load growth and the development of generation and market network services. This method is based on the presumption that the future economic beneficiaries can be reliably identified, which may be difficult to achieve in practice (this issue is discussed in more detail in Chapter 6). EnergyAustralia argues it would not be easy to apply the method to individual connection points. Thus, the LRMC method might lead to a high level of disputes that could be costly and time-consuming.

The Commission agrees with comments made by Energy Australia and TransGrid that it is undesirable to base the LRMC on the period covered by the annual planning review, rather than the life of the assets. As a result, price signals to encourage alternative investments would be confined to the few years when an augmentation was projected within the current planning period, but not yet committed.

The Commission is of the view that the LRMC method will be difficult to apply and requires arbitrary assumptions about future scenarios, and is therefore likely to be contentious. The subjectivity inevitably involved makes it difficult for participants to conduct their own scenario-based analyses to assess future usage price trends.

***Conclusion***

The Commission has concerns about the practicality of implementing the proposed arrangements for three different methodologies to be used to specify a range of prices. This proposal has the advantage that the reliance on any individual method is reduced but introduces an element of arbitrariness, which could become a source of contention and dispute, and makes it more difficult for participants to predict future pricing trends. The Commission also considers that having three methods is likely to heighten administrative costs and complexity, without any clear benefit to market participants.

A number of interested parties suggest that it would be better to specify a single default method, while allowing TNSPs some discretion to employ an alternative where there is a demonstrable benefit. The Commission agrees with this approach, as it reduces the likely costs and complexity, while still allowing sufficient flexibility to ensure better pricing outcomes result. Hence the Commission has imposed a condition of authorisation (C4.1) to remove the provisions allowing the TNSPs to select a transmission usage price from a range of prices determined using each of the 3 methods set out in schedule 6.4 of the code. Condition C4.1 requires the TNSP to determine a single cost for each connection point.

The Commission considers that all three of the proposed methods have limitations when assessed against the attributes of effective transmission usage price signals.

The Commission considers that the modified CRNP method (method 2 in schedule 6.4 of the code) potentially offers worthwhile improvements over the standard CRNP method for usage pricing purposes. However, as this method has not yet been fully tested in the NEM transmission environment, the Commission is of the view that as the CRNP method (method 1 in schedule 6.4 of the code) as a proven product, is the best default option. That is, the standard CRNP has the benefit of being well tested and understood in the NEM, and its ongoing use can be achieved with minimum cost and disruption to market participants. For this reason the Commission, while acknowledging its imperfections, has imposed a condition of authorisation (C4.1), requiring the standard CRNP method (method 1 in schedule 6.4 of the code) to be set as the default methodology for usage pricing purposes.

However, as the modified CRNP method has the potential to improve the price signals the Commission considers that a TNSP must be able to use the modified CRNP method, if the TNSP can demonstrate to the regulator better price outcomes result, and has imposed a condition (C4.1) accordingly. In granting TNSPs a choice of usage pricing method, the Commission considers that to minimise uncertainty and pricing inconsistency the choice of method must apply across the entire area for the pricing calculation is being undertaken.

While recognising the need to progress the network pricing arrangements the Commission remains of the view that both the CRNP and modified CRNP methods are far from perfect. Indeed, the lengthy review process that led to the present code change proposals arose out of concerns about the adequacy of the CRNP method at the time of the original authorisation of the code. The Commission considers that further work must be undertaken by NECA to develop a more robust network pricing methodology for the future. Such work should investigate possible efficiency improvements that may arise from:

- better integration of transmission pricing into the energy market;
- a modified regime of transmission usage prices; and
- the removal of the cap on price changes referred to in clause 6.5.5.

The Commission would like to see this work undertaken as soon as possible but recognises a need to balance this desire against the need to incorporate the outcomes of the RIEMNS review. For this reason the Commission has imposed a requirement for the review to be completed within 18 months of the date of this determination, and any code changes arising to be bought to the Commission within 3 months of the completion of the review. The review requirements are addressed in condition C4.2.

The Commission considers that important objectives of any new method should be to ensure that usage prices are consistent across the NEM, are transparently and objectively set, and take account of transmission usage signals elsewhere in the NEM.

The Commission agrees with several interested parties who argue that any further work on transmission pricing should be linked to NECA's RIEMNS. For example, the Commission acknowledges that if RIEMNS results in much better signalling through the energy market, then usage charges may only be needed to provide minimal, if any, signalling. However, if changes to the energy market are not made, then it will continue to be necessary to supplement the signals in the energy market with a regime of administered transmission usage prices. The Commission has therefore required that in developing the new usage charge method, NECA must have regard to the outcomes of RIEMNS.

In appendix D to this determination, the Commission has included some suggested possible improvements to the CRNP that NECA might like to take on board in developing a new usage charge method. The Commission also encourages NECA to consider alternatives to a CRNP based approach, such as that suggested by Morrison and Co[7], which involves extending the current approach for setting marginal loss factors to derive a set of price differentials that reflect marginal costs of both losses and congestion.

The proposed code changes are unclear about the timing of updating the transmission usage prices. Clause 6.5.4(e) implies that the cost allocation of usage charges is only updated once per regulatory control period (that is, once every five years). While this provides customers with a high level of certainty about their prices within each regulatory interval, it limits the ability of the usage prices to reflect evolving conditions. This increases the risk of delivering inappropriate signals.

However, the proposed clause 6.4.6(a) appears to imply an annual re-calculation applies, which will mitigate this effect. The Commission considers it appropriate that the TUOS usage prices be updated annually because:

- clause 6.3 envisages the cost allocation being done over a whole region or regions that might involve a number of NSPs on different phases of their regulatory cycles, thus it is not necessarily feasible to do the allocation during year one of all the NSPs' regulatory period.

- further price signals are likely to evolve during the regulatory period, through NECA's RIEMNS and further work on the TUOS usage prices. The Commission therefore considers that it is better to update the usage prices annually so as to avoid locking in prices for five years.

The Commission has imposed a condition of authorisation (C4.3) to remove any ambiguity regarding the annual calculation of TUOS charges.

The Commission, however, acknowledges the need for stability in prices and therefore considers that it is appropriate at this stage to maintain the two percent cap on the annual change in transmission prices at any connection point relative to the region average (clause 6.5.5). In the light of the requirement to recalculate Customer TUOS usage charges annually, the cap should be applied strictly on a year to year basis. Condition C4.3 also addresses this issue. However, if in the future the usage charge method allows for an option of longer term pricing, then the Commission considers that this cap should be removed.

The proposed code changes allowed for inter-TNSP allocations that impact on the general charge, and as such mask price signals. The proposed code changes delete the ability to perform a common calculation of usage charges over multiple regions and put in its place a requirement to allocate usage costs to connection points with adjoining networks. However the costs allocated to adjoining networks are ultimately recovered through general charges rather than usage charges, thus masking the price signals. The Commission considers that the previously authorised arrangements provide a better outcome in terms of preserving price signals to customers. Hence the Commission requires the deletion of the proposed amendments (C4.4).

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[7] Comments on the ACCC Draft Determination on Network Pricing: A Report to the National Generator Forum, Morrison & Co., 26 March 2001.

Another drawback of the proposed code changes relates to over-signalling. The existing code requires inter-regional settlements residues to be deducted from the revenue requirements of assets providing an interconnection before allocating costs using CRNP, ensuring that to some extent at least the TUOS charges take account of signals provided through the energy market. Under the proposed changes, the adjustment for settlement residues would affect the general charges but not the usage charges, resulting in an increased risk of over-signalling. The Commission is imposing a condition (C4.5) that the requirement to consider inter-regional residues when establishing customer TUOS usage charges be restored. Settlement residues will also be taken into account when establishing the amount of revenue to be recovered through customer TUOS general charges, in accordance with the proposed clause 6.4.3C.

The Commission acknowledges that the code is not precise as to how assets providing an interconnection are to be identified. This could well be a matter for consideration in the review required under condition C4.2.

The Commission also notes that chapter 6 of the code tends to use the terms price and charge interchangeably, potentially creating some confusion. The Commission considers the clarity of the code could be significantly improved if the term price was reserved for contexts where a rate or unit price was implied whereas the term charge was only used to refer to a dollar amount to be recovered. Thus for example a customer TUOS usage charge would represent the dollar amount to be recovered from a customer. This charge might have been calculated for example by applying a customer TUOS usage price expressed in $/MW to the customer’s maximum demand during a certain period. It should be noted that in the special case of a fixed charge, ie a charge which is the same for all payees, the price and charge would both have units of dollars and would refer to the same amount. The Commission is imposing a condition requiring the code terminology to be amended along these lines (C4.6).

### 4.2.6 Conditions of authorisation

**C4.1 The proposed provisions of the code relating to the calculation of customer TUOS usage charges and prices (including clause 6.4.3B and schedule 6.4) must be amended so that:**

**a) all references to a cost range and selection from within a cost range are removed;**

**b) a single cost for each connection point is established, instead of a cost range;**

**c) with the regulator’s approval, the modified CRNP method (method 2 of schedule 6.4) may be used to establish the cost at every transmission connection point within the entire area over which the pricing calculation is being undertaken;**

**d) if the modified CRNP method is not used then the standard CRNP method (method 1 of schedule 6.4) must be used.**

**C4.2 The code must be amended to require NECA, within 18 months of the date of this determination, to complete a review, in accordance with code consultation procedures, which examines whether:**

**(1) closer integration of transmission pricing into the energy market;**

**(2) a modified regime of transmission usage prices; and**

**(3) the removal of the cap on price changes referred to in clause 6.5.5**

**can be expected to improve the efficiency of the NEM, and make recommendations as to what changes (if any) should be made to the code. Any code changes arising from the above review must be brought to the Commission within 3 months of the completion of the review.**

**C4.3 The Code must be amended to ensure the provisions of chapter 6 of the Code unambiguously provide for TUOS usage charges to be recalculated annually. Clause 6.5.5 must be amended to clarify that the cap on the rate of change of prices is to be applied on a year to year basis and remove references to the regulatory control period.**

**C4.4 The proposed deletions to clause 6.3.4 must not be made. The proposed provisions for allocating costs to connection points with other networks must be deleted.**

**C4.5 Clause 6.19(c) must be amended to change the reference to clause 6.4.3C to 6.4.3B.**

**C4.6 Chapter 6 of the code must be amended such that the term price refers to a rate or unit price and the term charge refers to dollar amount.**

## 4.3 TUOS general charges

The proposed code changes replace the postage stamp component of TUOS charges with a general charge that recovers the balance of the TNSP’s AARR, after the TUOS usage charges and other items are added or subtracted (refer to appendix B for further details). The general charge is levied on customers as a fixed annual charge recovered via an energy related price.

### 4.3.1 What the interested parties say

Most of the comments that were made by interested parties regarding who should pay for TUOS charges did not differentiate between the TUOS usage charge and the TUOS general charge.

VENCorp considers that the clear intent from NECA’s review was that the customer TUOS general charge should be a fixed annual charge (ie. $ per annum) to transmission customers, allocated on a postage stamp basis in a manner which minimises distortion to existing price signals. VENCorp argues that this is not clear in the code changes, and in fact clause 6.5.4 of the code appears to provide TNSPs with the discretion to set prices for this component of the charge based on demand, energy or fixed charges or a combination of all three. However, VENCorp argues, clause 6.4.3C(d)(2) appears to imply that the general charge should be a fixed charge (as distinct from a fixed price). In addition, VENCorp states that clause 6.4.3C(b) does not allow for any adjustments for overs or unders in this charge, once again implying it should be a fixed annual charge.

Further to Powerlink's comments in section 4.5 of this determination, Powerlink argues that the customer TUOS general charge should not be adjusted for financial transfers between TNSPs.

### 4.3.2 What the applicant says

NECA argues that the general charge is designed to recover the balance of a TNSP's AARR (after the above deductions and additions) in as non distortionary a way as possible.

### 4.3.3 Other relevant information

*Murray and Mather*

In a report to NECA regarding the issue of who should pay for ancillary services, Murray and Mather state that the allocation of costs for services that are common to all participants can distort economic efficiency if it causes participants to change their behaviour. [8] Hence they argue that these charges should be allocated in a minimally distorting manner. Murray and Mather refer to optimal tax literature, which concludes that the dead-weight loss arising from allocating common costs is minimised if the charges are spread over as broad a base as possible.

Optimal tax literature also shows that the charges can then be refined using Ramsey pricing, which allocates costs on the basis of the inverse of participants' elasticity of demand. Such an approach would allocate higher charges to participants that are less responsive to price and vice versa. Murray and Mather acknowledge that it is often difficult to calculate elasticities and that in the absence of this information, the allocation of common costs over a broad base is a sound approach.

*NERA*

NECA engaged National Economic Research Associates (NERA) to provide advice in relation to the transmission and distribution pricing review.

On the question of who should pay transmission charges, NERA states that it depends upon customers' and generators' elasticities of demand with respect to the charges, but notes that it is often difficult to obtain such information. However, NERA asserts that

[8] Murray, K and Mather, J, 'Who Should Pay for Ancillary Services', 25 January 2000.

in order to avoid distorting usage, the additional charges needed to recover fixed costs (ie. charges other than marginal cost), '…must be fixed amounts per customer.'[9]

NERA argues that an advantage of imposing charges on both generators and customers is that the charges will be smaller and therefore less likely to have a significant impact on behaviour. NERA illustrates the points by giving the example that:

> with a 25 per cent margin of generation over non-coincident peak load, a $/kW charge spread over the kWs of both capacity and load would be around half (in very rough terms) a charge spread over only one or the other.[10]

*NEMMCO's Determination of the Structure of Participant fees*

NEMMCO's *Draft Report and Determination of the Structure of Participant Fees* draws on advice from London Economics (LE) regarding pricing options that can be used in the presence of fixed costs.

> A fee structure based on average cost pricing has significant implications for economic efficiency as the cost of energy increases uniformly by the average fee charged leading to, even under competitive market conditions, energy prices that are above marginal cost. Regardless of the participants to whom the variable charge is applied, consumption would be lower than the economically efficient level, resulting in a reduction in both consumer and producer surplus.
>
> …Fixed fees do not impact on consumption and production decisions *in the short term* but may affect long term entry and exit decisions. The result is that inappropriately structured fixed fees obviate competitive neutrality and discourage small participants from using the wholesale market…Properly structured fixed fees, whereby the size of the fixed fees is set at a lower level for smaller participants, can mitigate the problem of barriers to entry.[11]

LE supports the use of broadly based fixed charges to recover fixed costs. In NEMMCO's final determination, LE states that:

> In our view, given NEMMCO's generally fixed cost structure (in the short term at least), appropriately structure fixed fees, provided they do not affect decisions to participate in the market, are the preferred fee structure since they are least likely to distort consumption and production decisions…It should also be noted that NEMMCO is in the middle of the production chain for electricity. To the extent that its costs are fixed and have to be recovered, market efficiency is likely to be enhanced if they are charged to final customers in a manner which efficiently discriminates between those final customers. NEMMCO lacks information necessary to undertake this task. Market Customers and Generators [including MNSPs], who transact with Market Customers and final customers have a much greater ability to price discriminate.[12]

In a supplementary paper prepared for NEMMCO's review of participant fees, LE states that the NGF considers that:

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9 NERA, 'Principles of Efficient Pricing for Transmission and Distribution', April 1998, p.8. Note that here NERA is referring to a customer as a user of a firm's output, rather than a customer as defined in the code.
10 Ibid, p.21.
11 NEMMCO, 'Draft Report and Determination of the Structure of Participant Fees', March 2000, p.28.
12 NEMMCO, 'Final Report and Determination of the Structure of Participant Fees', 31 March 2000, p.30.

> fixed fees can only be considered fixed if they are entirely invariant with any aspect of participant behaviour or output;
>
> banded 'fixed' fees or 'fixed' fees based on market share (whether measured in terms of MWh or MW) are not truly fixed because they vary with some aspect of participant behaviour. Hence they are variable; [13]

However, LE states that:

> In assessing whether a charge is fixed or variable, one must also refer to the ability of the participant to affect the quantum of the charge within a specified time frame. A fee based on $/MWh is clearly variable on a half-hourly basis. A participant can influence the amount of fees paid by changing the quantity of energy consumed or produced. A fee based on installed capacity is however not variable to the same extent. That is not to say that this fee is absolutely invariant of the time horizon is sufficiently long. A generators can, for example, decommission a unit and thus reduce the charges based on installed capacity. However, a generator cannot vary the capacity installed on a half-hourly basis or even on a daily basis to avoid such fees. Charges based on MW capacity cannot thus be characterised as a variable charge to the same degree as an energy based charge. [14]

*ABARE's submission to NECA's review*

In its submission to NECA, ABARE states that:

> …efficient non-linear tariffs would then require that network owners be in a position to identify different user groups and tailor the tariffs to particular groups according to their elasticity of market participation with respect to prices and access fees. Alternatively, network service providers could be encouraged to offer self selecting two-part tariffs in which consumers are provided with a range of tariffs to choose from.

*Background papers prepared by NERA*

In background papers prepared for NECA's review, NERA states that transmission charges for the residual network costs should be structured so as to minimise the effect on network users' decisions both in the short and long runs. [15] However, NERA notes that if the spot market is not operating effectively there may need to be other options for providing efficient price signals.

NERA claims that a $/kW charge imposed on generators would not distort decisions over location or types of technologies. NERA also argues that a $/kW charge would not distort dispatch since it would not affect the marginal cost of generation. It would however affect long run decisions about market participation, for example by deterring new entrants that were just on the margin of expected profitability, or inducing the withdrawal of generating plant that was barely earning enough revenue to stay in the market.

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[13] London Economics 'Participant Fee Structure – Supplementary report to NEMMCO', March 2000, p.2.

[14] London Economics 'Participant Fee Structure – Supplementary report to NEMMCO', March 2000, pp.1-2.

[15] NERA, op cit, p.20.

*London Economics*

In relation to the current postage stamping arrangements, London Economics (LE) made the following comments:

> The question arises in the context of averaged energy charges whether a greater proportion of these (essentially fixed) costs should not be recovered via a fixed charge. Fixed charges – appropriately applied – are less distortionary than variable charges, are simple to apply, could be differentiated by size of customers, and would reduce the taxation impact on consumption.[16]

However, LE notes that DNSPs would need to modify their billing procedures if there is a move towards greater fixed cost recovery.

### 4.3.4 Issues arising from the draft determination

The draft determination imposed the following conditions of authorisation:

**C4.7 The code must be amended to require TNSPs to levy Customer TUOS general charges according to customers' energy consumed in the previous year.**

**C4.8 Clause 6.4.3C(b)(1) must be amended to remove the reference to clause 6.4.9.**

**C4.9 Clause 6.4.3C(c)(5) must be amended to remove the reference to clause 5.5(f)(3).**

**C4.10 Clause 6.5.4(c) must be amended to remove references to clause 6.5.4(a)(4).**

**C4.11 All references in the code to the 'Customer TUOS fixed charge' must be deleted and replaced by references to the 'Customer TUOS general charge'.**

Tarong, TransEnergie and SHTPL support the Commission's conclusion that the general charge should be levied on customers only, in order to minimise distortion.

The AEA queries the Commission's conclusion that a fixed charge levied on generators might deter future entry or lead current generators to reduce capacity or exit the industry. It considered this should not happen unless the TNSP were attempting to recover an inefficient level of TUOS for the relevant assets.

At the PDC, Transend argued that levying the general charge on the previous year's consumption would still be distortionary because it would penalise customers with high load factors. Transend supported ABARE's suggestion of self selection tariffs and indicated that this approach has been adopted in Tasmania. Customers are offered the choice of a $/MWh rate based on annual consumption and a $/MW rate based on contracted maximum demand, the rates being adjusted so that customers with average load factors are indifferent. Transend argued this was more equitable and also practicable. TransGrid also urged the Commission to consider this proposal.

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16 London Economics, 'Review of Australian Transmission Pricing - A Report for the ACCC', April 1999, p.87.

Western Power similarly argues that basing general charges on energy consumption would penalise customers with high load factors or demands which fell outside peak hours unless there were different rates for peak, shoulder and offpeak hours. Western Power is also concerned that an energy-based charge would not adequately cover connection points requiring standby network service. Western Power indicates that in WA, general charges are based on reserved capacity and recommended that the Commission include a similar option. If charges are based on previous year's consumption the issue of charges to new customers should be addressed.

The AGO states that, as with the usage charge, all network users should be exposed to the general charge. It argues that restricting the charge to customers would fail to minimise dead-weight loss and would be less equitable. The AGO is of the view that basing general charges on the previous year's consumption might still distort market outcomes, in particular by delaying and hence diminishing the economic rewards for investments in end use efficiency. It recommends that alternatives to the recovery of sunk costs be explored.

TransGrid, speaking on behalf of TNSPs, agrees that general charges should be recovered so as to minimise the influence on customer behaviour. TransGrid indicated that electricity studies illustrate demand for electricity is inelastic, meaning the charge will not have a major impact on usage. TransGrid contends that the proposal to base the charge on last year's usage is not practical. TransGrid argues that the proposal will not be able to deal with a new customer or a customer with a step change in demand. TransGrid states that most TNSPs are attracted to the ABARE/Transend proposal and urges the Commission to consider it.

### 4.3.4 Commission's considerations

*Structure of TUOS general charges*

Given economies of scale, system security requirements and reliability driven transmission network investment the total amount that is recovered from TUOS usage charges will generally be below the TNSPs' AARR. The Commission considers the additional charges that are necessary to recover the TNSPs' AARR should be imposed in a minimally distorting manner, so as to preserve the marginal cost signals delivered through the spot market and the TUOS usage charge.

The general charge is the mechanism designated in the code for the recovery of the residual element of the TNSPs' AARR, and it is intended to operate as a fixed charge. In principle, a fixed charge can minimise distortions as it will not vary in response to participants' market activities.

However, the Commission notes that the proposed code changes are ambiguous as to whether the TUOS general charge is in fact a fixed charge. Clause 6.5.4(a)(4) specifies the customer TUOS general charge is a fixed price, but clause 6.5.4(c) specifies that prices referred to in 6.5.4(a) (which includes the customer TUOS general charge) may include one or more of demand based charges, energy based charges and a fixed charge. Further, clause 6.4.3C(d) states that the general charge must be allocated to connection points on a postage stamp basis and then recovered through a fixed charge, which is calculated on a postage stamp basis.  This is not a truly fixed charge as it varies according to energy consumption.

Therefore, even accepting there is some confusion between the current code provisions and the code changes, there does appear to be the scope for TNSPs to levy general charge as a variable charge, based on transmission customers' current year's energy consumption or the current year's maximum demand.

The Commission has concerns that such an approach could cause participants to adjust their consumption or maximum demand in order to minimise or avoid the charge.  This would result in inefficiencies since the charge is intended to be non-distortionary to participants' behaviour.

The Commission supports the view expressed by NERA and LE that the least distortionary means of recovering fixed costs (in terms of impacts on network utilisation) is by imposing a fixed charge.  However, it is very difficult in practice to levy a truly fixed charge that does not affect participants' behaviour.  A fixed charge, (for example, $ per year) would be applied equivalently to all participants regardless of their size.  Such a charge would be a large impost on small participants and could result in a significant price shock relative to the current arrangements.  It would impose a perverse incentive on such participants to exit the market.

The Commission therefore considers that the general charges should be structured so as to preserve the intent that they be non-distortionary to consumption and investment decisions, while minimising the impact of any price shocks.

In the draft determination, the Commission imposed a condition of authorisation that sought to make the general charge more fixed in nature so that participants would be less likely to adjust their consumption in order to avoid the general charge.  The Commission required that the code must be amended to require TNSPs to levy the TUOS general charges according to energy consumed in the previous year.

However, an energy based charge, even if determined on the previous year's consumption, may still be distortionary for high load factor customers.  The Commission notes Transend has implemented a menu based approach in which customers self-select between an energy based charge and a charge based on contracted maximum demand.  Assuming contracted maximum demand is an essentially fixed quantity, a charge based on it should not be distortionary for high load factor customers. It could have a significant impact on customers with low load factors but the menu approach allows them to select the energy-based alternative, which should be less distortionary in their case.

The Commission supports the menu approach, however it acknowledges that the practicality of applying it would depend on whether a measure analogous to the contracted demand could be agreed for each connection point.  The measure would need to relate to offtake capacity and should be effectively fixed and immune to manipulation.  For example it would not be desirable to substitute a charge based on actual demand, since such a charge would be more likely to influence participants' behaviour.

Western Power recommends that if an energy-based charge is retained, different rates should be struck for on-peak, shoulder and off-peak hours. However such differentiation would conflict with the purpose of the general charge: to recover the balance of the required revenue without influencing participants' behaviour.

Western Power also suggests that if charges are to be based on the previous year's energy consumption, the issue of charges for new customers' first year should be addressed. The Commission agrees and has therefore required that in the case of new customers, their general charge should be based on their actual consumption.

The Commission has imposed a condition of authorisation (C4.7) that the code must be amended to specify that the default method for calculating TUOS general charges must be on the basis of total energy consumption in the preceding year, or current consumption in the case of new participants. Wherever practicable, an alternative charge must be offered for each connection point that is based on an agreed offtake capacity or contracted maximum demand.

*Who pays*

The Commission's assessment of who should pay general charges is closely linked to the structure of general charges and as such, needs to consider the broader context of the best practice arrangements for delivering efficient network prices.

The Commission considers that in the case of a fixed charge levied as an absolute amount, it is clear that the least distorting application is to levy customers only. This is because in a competitive generation market the spot market price under normal system conditions will be driven by the marginal cost of generation. Thus in the short term generators will not pass a fixed charge through in such a situation since their bidding strategy will be determined by their marginal cost of production, rather than fixed costs. Further, in the longer term, fixed charges may impact on generators' decisions regarding market entry and exit and hence the structure of the generation sector.

For example, a fixed charge may lead small or marginally profitable generators to withdraw from the market. Further, it may be seen as a barrier to entry to small, local generators that provide other system wide benefits to the NEM through the deferral of augmentations. Another result of fixed charges, could be an increase in mergers or acquisitions in order to avoid the charges. In this regard, the Commission notes the concerns raised by the SA Treasury that charging generators sunk costs may weaken the NEM because generators may directly connect to customers to avoid the fixed charges. Thus, the Commission can see no benefit from applying a fixed general charge to generators. At best it will be equivalent to a variable peak charge on customers and at worst it will distort the structure of the generation industry, which could have potential negative ramifications for the energy market, as well as the ancillary service markets and customers' decisions regarding network bypass.

However, the Commission notes that the TUOS general charge is effectively a variable charge, although it is not designed to provide investment or utilisation signals. The Commission considers the likely outcome of imposing the variable TUOS general charge on generators would be higher spot market prices, since all generators could pass through the uniform $/MWh charge without altering their relative positions in the dispatch merit order. Therefore levying the general charge on generators, where it does not provide utilisation or investment signals (since these are provided through the usage charge), will not provide the best economic outcomes and will generally be passed through to customers rather than being absorbed.

Given that the general charge is intended to recover the residual costs of the network in a non-distortionary manner, the Commission accepts NECA's proposal that TUOS general charges continue to be levied on market customers only.

The Commission also recognises that decisions about building regulated or unregulated interconnectors may be distorted by levying the TUOS general charge on transmission connected MNSPs. Currently, regulated interconnectors do not pay TUOS general charges, therefore there could be an incentive to invest in this type of interconnector relative to a market network service, which would effectively include a tax component in its costs.

The AEA suggests that a fixed charge on generators should not be distortionary unless an inefficient level of TUOS is being sought. However, the Commission is concerned that, even if the total revenue being recovered is not excessive, a fixed charge may significantly impact on smaller generators and co-generators in particular. Peaking and standby generators might also be significantly impacted if the charge were based on registered capacity.

The AGO is concerned that dead-weight losses may not be minimised if the charge is restricted to customers. The Commission agrees that broadening the horizontal base over which the charges are spread will reduce deadweight losses. It is not convinced that a similar reduction will be obtained over the long term through vertically broadening the base by applying the charge to generators and MNSPs. The charges would add to the costs of new entrants and thus influence the price threshold at which they are willing to enter the market. Hence, in the long run, the charges are likely to be passed back to customers, probably in a more distortionary form.

*Under and over recoveries*

Under the proposed code changes the possibility exists that the TNSP may under or over recover the general charge in any given period, particularly where the charge is based on customers' consumption in the previous year during periods of uncertain load forecasts.

Under the proposed code changes, the general charge is intended to recover the balance of the TNSP's annual revenue requirement. The rate must be struck each year before it is known precisely how much revenue will be recovered through other charges. The code changes therefore provide for a correction for under or over recovery in the following year. To ensure TNSPs have no systematic incentive to over recover, the Commission believes the amount of the correction should be adjusted in accordance to the length of time the money has been held by (or owed to) the TNSP. The adjustment should use an interest rate that has been approved by the regulator. The Commission has imposed condition C4.8 to address this issue.

*Other considerations*

Similarly to the arrangements for the usage charge, the Commission believes that the general charge should also be recalculated each year, and requires the code to be amended to unambiguously provide for that (C4.9).

The Commission notes that the proposed code changes regarding the TUOS general charge contain a number of drafting errors.

In specifying amounts to be deducted from the AARR to calculate the TUOS general charge, clause 6.4.3C(b)(1) refers to the recovery of charges from costs allocated in accordance with clause 6.4.9. However, the proposed code changes delete clause 6.4.9 from the code.

Similarly, in specifying amounts to be added to the AARR to calculate the TUOS general charge, clause 6.4.3C(c)(5) refers to amounts TNSPs are required to pay generators in accordance with clause 5.5(f)(3). However, the proposed code changes delete clause 5.5(f)(3) from the code.

Clause 6.4.3C(a) provides that the residual of the AARR after all other charges are deducted is to be recovered through the TUOS general charge. However, various other clauses of the code refer to this charge as the customer TUOS fixed charge. To improve the clarity of the code the Commission has required that references to customer TUOS fixed charge be replaced by customers TUOS general charge.

The Commission has imposed conditions of authorisation (C4.10, C4.11 and C4.12) to correct these drafting errors.

Further, the Commission considers that clause 6.4.3(e) is unnecessary. Clauses 6.4.3C and 6.5.4, once amended to take into account condition C4.7 above, are adequate to deal with situations where the amount to be recovered through customer TUOS general charges is negative. A few amendments might be desirable to clarify that references to cost recovery would imply rebating of monies where the amount to be recovered was negative. Therefore in the interests of simplifying the code and removing a possible source of ambiguity the Commission requires the clause 6.4.3C(e) to be deleted (C4.13).

### 4.3.5 Conditions of authorisation

**C4.7 Clauses 6.5.4 and 6.4.3C(d) of the code must be amended to specify the following method for calculating the customer TUOS general price to have effect at each relevant transmission connection point during a particular financial year and the way in which it must be applied to compute the customer TUOS general charge to be levied at that connection point during the financial year:**

**a) The customer TUOS general price to have effect at a connection point during the particular financial year shall take the form of either (i) an energy price ($/MWh) or (ii) a capacity price ($/MW);**

**b) The applicable price shall be whichever of the above forms results in the lower customer TUOS general charge when applied as described in (d ) and ( f) below, subject to the proviso that the capacity price can only be utilised where the circumstances specified in (e) apply;**

**c) The energy price shall take the same value throughout the region or regions over which the price calculation is being made and likewise the capacity price;**

**d) The energy price shall apply to the total metered energy offtake at the connection point during the financial year completed twelve months prior to the start of the financial year for which the price has effect excepting that (i) if the requisite metering data are unavailable or (ii) in the case of a new customer or (iii) with the approval of the regulator, the price shall apply to the total metered energy offtake during the financial year for which the price has effect;**

**e) The capacity price can only be utilised at a connection point if the customer's connection agreement or other enforceable instrument nominates a fixed maximum demand for that connection point together with substantial penalties for exceeding;**

**f) The capacity price shall apply to the fixed maximum demand referred to in (e)**

**g) The customer TUOS general charge to be levied at the connection point during the financial year, or to be rebated if the calculated amount is negative, shall be the dollar amount which results from applying the applicable price, determined in accordance with (b) above, which is to have effect during the financial year. The amount shall be computed as specified in (d) or (f) (whichever is appropriate);**

**h) The values for the energy price and the capacity price are to be selected so that (i) a customer with median load factor will be substantially indifferent as to which is applied and (ii) the total revenue recovered or rebated through amounts calculated in accordance with (g) will (neglecting the effect of any negotiated price discounts and relying on forecasts of energy usage where necessary) equal the amount determined in accordance with clause 6.4.3C(a).**

**Clause 6.4.3C must be amended to ensure that under or over recovery of revenue through customer TUOS general charges in one financial year is taken into account in setting Customer TUOS general prices in subsequent years.**

**C4.8 Clause 6.3.4C must be amended to provide that any under or over recovery of revenues to be taken into account in calculating the general charge the following year, must be adjusted to reflect the length of time it has been held by or owed to the TNSP. The interest rate to apply in the adjustment must be approved by the relevant regulator.**

**C4.9 The code must be amended to specify that the calculation of customer TUOS general prices is to be repeated annually.**

**C4.10 Clause 6.4.3C(b)(1) must be amended to refer to clause 6.4.8 instead of 6.4.9.**

**C4.11 Clause 6.4.3C(c)(5) must be amended to replace the reference to clause 5.5(f)(3) with a reference to 5.6.2(m).**

**C4.12 All occurrences in the code of 'Customer TUOS fixed charge' must be deleted and replaced by references to the 'Customer TUOS general charge' or 'Customer TUOS general price', as appropriate.**

**C4.13 Clause 6.4.3C(e) must be deleted.**

## 4.4 Common service charges

A common service is one that cannot reasonably be allocated to network users on a locational basis. Under the existing arrangements, common service costs are recovered through an energy-based charge based on a rate that varies at each connection point according to the assessed utilisation of different networks. Changes proposed by the applicant would require the rate to be uniform for all connection points in a particular network.

As noted in the draft determination, common service costs have many of the characteristics of fixed costs: the Commission understands that the incremental common service cost associated with the advent of a new network user is very small. Accordingly, it is appropriate for the common service charges to be structured similarly to the general charge. In both cases the primary aim should be to recover the required revenue with minimal distortion. The Commission therefore endorses NECA's proposal to move to a uniform rate. However, as discussed in section 4.3 in relation to the general charge, the Commission believes the distortionary impact is likely to be reduced if the rate is applied to historical energy consumption rather than present consumption, and if high load factor customers have access to an alternative capacity-based charge. The Commission is imposing a condition to that effect.

### 4.4.1 Condition of authorisation

**C4.14 Clauses 6.4.4 and 6.5.6 of the code must be amended to specify a method for the calculation of common services prices and charges that is similar to that required for customer TUOS general charges in condition 4.7.**

## 4.5 Negotiation of price discounts

Prices determined in accordance with the code's principles are maximum prices. Customers can seek to negotiate a discount on these maximum network prices. Customers also have an unrestricted right to bypass the network. NECA's review affirmed this right on the basis that it provides a competitive spur to the TNSPs.

The code changes allow TNSPs to recover the negotiated discount on the TUOS general charge from other customers, provided:

- the network complies with any relevant requirements of the ACCC;
- the negotiated price includes a customer TUOS usage charge which falls within the cost range established for that charge; and
- the ACCC agrees that the TNSP's calculations of the customer TUOS usage and general charges are consistent with the code principles.

### 4.5.1 What the interested parties say

*Customers better off*

TransGrid, the SA Treasury and SPI PowerNet argue that compared with the situation where a major customer does not connect, closes down or relocates as a consequence of not being able to negotiate a discount, other grid users will in fact be better off if TUOS discounting is allowed.

*Incentive to limit discounts*

TransGrid argues that TNSPs already have an incentive to limit discounts to those cases that have a genuine bypass or walk away option. If TNSPs offer too many or too large discounts, the general charges for remaining customers will rise leading to the risk that these customers will also bypass the network, leaving assets stranded. For this reason TransGrid argues that there should be no prescribed limits on discounts. If, however, restrictions were placed on the level of discounts, then TransGrid believes that it would be preferable to impose explicit principles in the code on which negotiations would be based, rather than allowing the Commission to impose any relevant requirements on the TNSP while approving a discount methodology.

The SA Treasury and EMRI argue that TNSPs should not be able to fully recoup the lost revenues from any price discounts. They argue that this would provide TNSPs with incentives to maximise revenue through negotiations and to negotiate in order to avoid bypass.

Powerlink states that NECA's review envisaged price negotiation as only occurring in exceptional circumstances, such as to avoid uneconomic bypass. Powerlink argues that the provision of discounts outside these circumstances would produce large inequities between customers.

VENCorp agrees with Power link and states to prevent such outcomes from occurring discounted network charges should be restricted to a very limited number of cases, and that the ACCC should publish some guidelines to this effect.

*Equity*

The SA Treasury has concerns that small rural customers may not have enough bargaining power to enable them to gain a discount and as a result there may be a shift in general charges from larger urban customers to smaller rural customers.

Ergon and the EMRI disagree with the proposal to allow TNSPs to recover discounts from other customers because, they argue, it is inequitable that customers with lesser negotiating power are required to pay for the negotiating success of other larger network users.

BDB argue that the recovery of sunk costs should be done equitably, but believes that allowing any party to negotiate on the basis of price sensitivity will invite all parties to be price sensitive.

VENCorp questions whether the proposed discounting provisions of the code changes meet the equity objective in the code. VENCorp's concern is based on the possibility that two customers at the same connection point will have different prices, simply due to their ability to negotiate a discount. As a result VENCorp argues that those customers with the least ability to negotiate discounts could be left paying an increasing proportion of the sunk costs of the transmission network.

*Pricing to avoid competitive pressures*

The AEA argues that the ability of TNSPs to negotiate price discounts to price sensitive customers and recover such discounts from remaining customers effectively allows TNSPs to entrench their monopoly power by out pricing by-pass and non network options. AEA considers the ability to recover discounts from other customers creates perverse incentives for TNSPs to structure prices to avoid competition from non-network alternatives, even where the alternatives are efficient. The AEA believes these negotiation provisions are contrary to the anti-discriminatory and pro-competitive provision in the code.

*Negotiation framework for price discounts*

The AEA, Ergon, the SA Treasury, SPI PowerNet and EnergyAustralia all argue the there should be a negotiation framework for customers to fall back on if the TNSP is not negotiating in good faith.

VENCorp argues that the TNSP's decision to decide whether a customer should receive a discount or not, based on its ability to bypass, is very subjective and requires information disclosure by both parties.

*Publication of discounts*

The SA Treasury states that the public release of information regarding price discounts should be limited to an aggregate level rather than an individual customer basis. It agues that providing customer specific information could provide competitors with information about costs.

The AEA and Ergon argue that the details of any discounts that are to be borne by other customers should be released to ensure all customers are in the same bargaining position.

TransGrid argues that it is neither necessary or desirable to make the outcome of price negotiations public.

EnergyAustralia argues that such information should be available to the regulator but not necessarily made publicly available.

Powerlink argues only the revenue from negotiations should be publicly released, since this will impact on the calculation of regulated revenue to be collected from others.

Powerlink also argues that it is unreasonable to require TNSPs to justify their charges in the circumstances where the party applying for the discount is also a potential competitor to the TNSP, such as local generation or MNSPs.

*General*

VENCorp states that the TNSPs' ability to negotiate discounted network charges with selected customers needs to be clarified. VENCorp believes the clear intent of NECA's review was that only the customer TUOS general charge could be discounted and that the discount could be recovered from other customers through an adjustment in general charges. VENCorp argues that clause 6.5.8(c) appears to suggest that customer TUOS usage charges could also be discounted and that any discounts could be recovered through both general and usage charges.

The BCA ERTF argues against the proposal to allow TNSPs to negotiate discounts with price sensitive customers and then to recover the lost revenue from other customers. The BCA ERTF argue that charging these customers above marginal cost is in effect a quasi tax on an intermediate input which causes distortions and allocative inefficiency. The BCA ERTF argues that this is anti-competitive and is in conflict with principles of the code.

### 4.5.2 What the applicant says

NECA argues that the existing provisions for discounting TUOS general charges to individual customers will encourage the efficient use of the network and prevent uneconomic bypass. NECA argues that the code changes that allow TNSPs to recover discounts from other customers will ensure that other customers benefit from retaining some contribution to network costs by parties who might, under current code arrangements, be led to bypass. NECA's proposals give TNSPs the ability to recover discounts within the regulatory review period in which the discount is negotiated.

NECA considers that it is unnecessary to have a detailed negotiating framework for network users and TNSPs to use when negotiating discounted TUOS charges because there are incentives on both parties to negotiate.

### 4.5.3 Issues arising from the draft determination

The draft determination imposed the following conditions of authorisation:

**C4.12 Clause 6.5.8(c) must be amended to clarify that only discounts negotiated in relation to customer TUOS general charges and common service charges are recoverable from other customers.**

**C4.13 Clause 6.5.9 must be amended to prevent TNSPs from recovering discounts from other customers unless the relevant regulator has approved the discount at the next regulatory control period.**

**C4.14 Clause 6.5.8(c)(1) must be amended to state that the agreed reduced price must include a TUOS usage charge calculated in accordance with the code.**

**C4.15 Clauses 6.5.8(c)(2) and 6.5.8(c)(3) must be deleted from the code.**

**C4.16 Clause 6.5.8 must be amended to require TNSPs to publish aggregate information on the price discounts negotiated under clause 6.5.8.**

**C4.17 The reference in clause 6.4.3C(b)(6) to clause 6.5.9 must be replaced with a reference to clause 6.5.8.**

The Newcastle Group and the NSW Treasury argue that provided the usage price could not be discounted and accurately signalled long run incremental cost (LRIC), discounting the general charge would not involve any cross subsidy, and so would not be anti-competitive. The Newcastle Group considers that while LRIC would be difficult and arbitrary to calculate on a network-wide basis, it might be practicable on a particular line or a defined group of assets.

TransGrid suggest a secondary objective should be to ensure the discount was no larger than necessary: the discounted price should not be materially lower than that needed to keep the customer from walking away. The NSW Treasury suggests that TNSPs should be allowed to discount the general charge at their discretion unless it could be clearly shown that they were charging well below the cost of any feasible bypass option.

The AEA and Origin do not believe that TNSPs should be able to recover the costs of discounting from other customers. The AEA is concerned that TNSPs might take advantage of these provisions to price competitive alternatives such as local generation out of the market while still retaining their revenue base. It argues that at a minimum, TNSPs should be required to fully disclose the amount of the discount and to whom it was made. Origin considers that the recovery of discounted charges from other users will create perverse price signals.

Tarong also disagrees that discounting costs should be reallocated to other users, arguing that the need to offer the discount will signal that the value of the relevant network assets was less than that previously determined for the purposes of setting the revenue cap. Nevertheless if some cost recovery was to be allowed, a proximity test should apply: it would be unreasonable for customers hundreds of circuit kilometres from the discounted customer to see increased charges.

The NEDF on the other hand supports the provisions for recovery of discounts but is concerned that it will result in information asymmetry in favour of the customer. Customers would know that the floor for discounting was the usage price and would seek discounts to that level. The TNSP would be unable to objectively evaluate any claim by the customer that the full price would lead to failure of the business. The NEDF advocates uniform negotiating guidelines to apply to all parties, with clarity on the regulatory treatment of discounts.

In its draft determination, the Commission concluded that the impact of a customer's retention on asset valuation should be taken into account in deciding whether the full amount of a discount should be recoverable from other users. The Newcastle Group argues this raises only equity issues and that the Commission should not sacrifice efficiency for equity where competition is not compromised: that type of trade-off is a role for jurisdictions. The NSW Treasury is concerned that the Commission's proposal will dilute the incentive on TNSPs to negotiate discounts, with consequent inefficient outcomes. TransGrid considers the approach will lead to inefficient use of the existing network and will be impracticable because of the complexity of the necessary what if modelling.

Powerlink is concerned that delaying regulatory approval for cost recovery until the next control period will prevent financial closure on successful investments, with all parties failing to capture the potential benefits. At a minimum, guidelines should be specified that would allow the NSP to negotiate with some confidence. Discounts to new customers should be recoverable from the date of negotiation, rather than the next reset. Likewise TransGrid and Western Power consider discounts should be recoverable from the date of their commencement and that discounting guidelines should be codified. TransGrid considers the ACCC should be obliged to approve the discount if the guidelines had been properly followed.

TransGrid and VAW stress the need to be able to negotiate long term pricing certainty where required.

The NSW Treasury argues that confusion and uncertainty over the framework for discounting is currently leading to public detriment in New South Wales and requests that the Commission act immediately to endorse a simple and predictable framework. Likewise Powerlink states that the absence of provisions for negotiating TUOS discounts is stifling the progress of new energy intensive developments in Queensland.

### 4.5.4 Commission's considerations

*Recovery of costs of discounts to general charges*

The Commission considers that in some situations there may be benefits in allowing TNSPs to recover the cost of discounted general charges from remaining customers. For example, if an existing or potential network customer receives a discount that is less than the full general charge, then this customer will still be contributing, albeit partially, to the cost of the existing network. This will result in a public benefit because all remaining customers will be better off (by paying lower general charges) than if the customer left, or chose not to connect to, the network.

However, the discounting arrangements in the code need to place incentives on TNSPs to ensure they only offer discounts to customers where there is a genuine possibility that they will leave the network or choose not to connect. Further TNSPs should have the incentive to limit discounts to the minimum amount necessary to ensure the customer connects, or stays connected, to the network. The Commission agrees with the ACA that there also need to be incentives to ensure that TNSPs do not structure prices to avoid competition from more cost-effective non-network options.

In its draft determination, the Commission sought to introduce such incentives by preventing TNSPs from recovering the cost of a discount from other users until the regulator approves the cost recovery at the time of the next revenue regulatory decision. However, Powerlink, TransGrid and Western Power have raised concerns with this proposal, arguing that delaying regulatory approval will prevent financial closure on successful investments, with all parties failing to capture the potential benefits.

The Commission accepts that benefits can be foregone through uneconomic bypass if a TNSP fails to make a timely offer of an appropriate discount. On the other hand unnecessary discounting, unless absorbed by the TNSP itself, increases the amount of revenue to be recovered through general charges on other customers, thereby increasing the distortionary risks that compulsory cost recovery inevitably involves, as well as raising issues of equity. Desirably TNSPs should have, and be seen to have, incentives to take a balanced approach to discounting.

A TNSP has an incentive to offer selective discounts where it believes that its future annual revenue will thereby be preserved or enhanced. The Commission's proposal to delay cost recovery was designed to impose a countervailing incentive not to over-discount. However the Commission acknowledges that delayed cost recovery may lead TNSPs to offer too few or too low discounts, again distorting the incentives on the TNSPs.

The Commission considers that the TNSP will face a better incentive to offer appropriate discounts if it is aware of the circumstances in which the cost of the discount can be recovered from other users. The Commission therefore considers it appropriate that it develop guidelines that clearly set out the circumstances in which TNSPs can recover the cost of a discounted general charge from other users. This is consistent with the general approach to regulating TNSP's revenues, whereby the Commission has produced Draft Regulatory Principles to give TNSPs certainty about how they will be regulated. The Commission will shortly release draft Guidelines for the Negotiation of Discounted Transmission Charges for consultation.

The Commission has imposed a condition of authorisation (C4.15) that allows TNSPs to recover the cost of a discounted TUOS general charge from other users provided that the TNSP can demonstrate that the discount complies with the Commission's guidelines.

The proposed code changes provide for TNSPs to enter into discount arrangements and recover a discounted general charge from other customers, from the time the discount is negotiated. However, at the next regulatory reset if the TNSP cannot demonstrate that the discount complied with the guidelines then the Commission considers it should be able to claw back the revenue that the TNSP had earned from recovering the cost of the discount from other users. The Commission has imposed a condition (C4.16) to ensure that the regulator has such powers.

The TNSP will therefore have an incentive not to discount to unnecessary levels as it will know that if it does so, in contravention of the guidelines, then it will have to absorb the cost of the discount itself. The Commission will monitor the outcomes of negotiated discounts to ensure the arrangements are working as intended and that the discounts offered fall within the range established by the guidelines and demonstrated by the information provided by the TNSP.

The Commission is aware some TNSPs are currently being asked to negotiate discounts with prospective customers, but are hampered by the need to await implementation of code changes arising from the authorisation process and development of the Commission's guidelines. The Commission considers it is appropriate to provide some guidance to such TNSPs so appropriate discounts can be negotiated in a more certain environment. The Commission has imposed a condition (C4.17) requiring a transitional clause to be inserted into the code such that any discounts negotiated prior to the Commission's Guidelines for the Negotiation of Discounted Transmission Charges being finalised, must be submitted to the regulator for approval. In assessing any such applications the Commission will maintain consistency with the draft guidelines, to the extent possible.

Tarong suggests that the offering of the discount is evidence that the value of the relevant assets is less than that assumed for the purposes of setting the revenue cap and that the revenue cap should therefore be reduced, ie the discount should be absorbed by the TNSP. The Commission agrees that the need to discount would imply a limited value as far as the particular customer was concerned. However for shared assets, this would not necessarily imply that the assets' value to the market as a whole was diminished.

Tarong also suggests that if some cost recovery from other customers is allowed, a proximity test should apply on the grounds that it would be unreasonable for customers hundreds of circuit kilometres away to see increased charges. The Commission accepts there is intuitive appeal in Tarong's argument. However this is counterbalanced by the desirability of applying the general charge in a way that recovers the balance of the assessed revenue with minimum distortion. In principle, this is best achieved by applying the charge as broadly and uniformly as possible. Further, the Commission considers that any attempt to selectively apportion the discount recovery based on circuit kilometres will increase the complexity of the arrangements, but will not lead to improved outcomes overall.

The AEA is concerned that TNSPs may take advantage of the cost recovery provisions to price competitive alternatives such as local generation out of the market. However two factors should mitigate against this. Firstly, the usage charge, which is intended to reflect avoidable costs, cannot be discounted and will be rebated to embedded generators[17]. This should help ensure that local solutions receive appropriate competitive advantage, regardless of any discounting of the general charge. Secondly, the Commission has imposed safeguards to ensure that TNSPs have a disincentive to discount beyond a level that is economically justifiable.

The Commission's draft determination states that a TNSP should not be able to completely recover the cost of a discount from other users if, in the absence of a discount, a customer would have left the network and some transmission assets would have been either under-utilised or stranded. In that circumstance the asset should be

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[17] Usage charges may recover about half the total revenue requirement for shared assets if the standard CRNP method is used. The amount may be higher or lower if the modified CRNP method is adopted.

either written down or taken out of the regulatory asset base. If a customer receives a discount and remains connected to the transmission network, the beneficiaries would include other customers (through the customer with the discount at least partially contributing to general charges) as well as the TNSP (through maintaining the value of its regulatory asset base and therefore its AARR).

The Newcastle Group, TransGrid and the NSW Treasury disagreed with the Commission's approach, arguing that it would lead to inefficiencies by discouraging TNSPs from offering legitimate discounts and could be impracticable to implement.

The Commission maintains the view set out in the draft determination. The Commission considers that exposing TNSPs to the risk of optimisation will ensure that remaining customers will be no worse off, in the long term, than if the customer receiving the discount had instead decided to walk away. The optimisation process involves the Commission conducting an assessment of the general charges that the remaining customers would have paid if a customer connected to the network and received a discount compared to the general charges that the remaining customers would have paid had the asset been optimised down. This is in accordance with the processes set out in the DRP and the Commission notes that where a stranded asset risk is identified by the TNSP, the DRP process provides for some relief to the TNSP. The Commission will elaborate on this approach in its Guidelines for the Negotiation of Discounted Transmission Charges.

Proposed clause 6.5.8(d) requires the Commission to have regard to the potential loss of revenue for the TNSP that could result from the network being bypassed. The Commission considers that this clause is redundant, as bypass should only occur when economically justified. Further, the Commission considers that TNSPs should not be protected from the risk of asset stranding due to a customer bypassing the network and considers that this clause is inconsistent with the optimised depreciated replacement cost approach that the Commission uses to value transmission assets. The Commission has imposed a condition (C4.18) that clause 6.5.8(d) be deleted.

Clause 6.5.8(c)(1) of the code changes states that discounts are recoverable from other network users provided the agreed reduced price includes a TUOS usage charge which falls within the cost range determined by the three methods for TUOS usage charges. As discussed in section 4.2 of this determination the Commission has imposed a condition of authorisation that requires NECA to replace the code changes relating to a cost range and specify CRNP as the default method, and modified CRNP as an alternative method, to be used subject to regulatory approval. In light of this decision, clause 6.5.8(c)(1), which requires the agreed reduced price to include a TUOS usage charge that is within the cost range, is now superfluous. Further, the Commission believes that it is inappropriate for the code to allow TNSPs to negotiate discounts with respect to the usage charge. Condition C4.19 requires the deletion of proposed clause 6.5.8(c), to address these issues.

Clauses 6.5.8(c)(2) and 6.5.8(c)(3) of the code changes require TNSPs to have the method used to calculate the discounted customer's TUOS usage charge and general charge approved by the Commission before the discount can be recovered from other customers. In section 8.1 of this determination, the Commission imposes a condition of authorisation that the code must be amended to require TNSPs to publish the method used to calculate TUOS usage and general charges and the actual charges, while protecting confidentiality requirements of the network users. The Commission has also made it a condition that network users must be able to request information relating to their own charges and how they have been calculated. It is therefore unnecessary for the Commission to approve that the TUOS usage and general charges for the connection point at which the discount applies comply with the methods set out in the code. Condition C4.19 as discussed above also addresses these issues.

The Commission is also concerned that clause 6.5.8 uses the term *Code Participant* and hence would not allow consumers who do not purchase through a retailer or the spot market to negotiate discounted charges with TNSP. The Commission has therefore imposed a condition (C4.20) that this clause be amended to use the term *Network User*.

Clause 6.1.5(b) of the code sets out a timeframe for the Commission to give its approval in relation to clauses 6.5.8 and 6.5.9. However, given the Commission has required the removal of its role in approving the method used to calculate the discounted customer's TUOS usage charge and general charge and its role in approving the negotiation framework (see section 7.2 of this determination), this renders clause 6.1.5(b) redundant. The Commission has imposed a condition (C4.21) that clause 6.1.5(b) be deleted.

*Negotiating Framework*

The Commission considers it important that TNSPs and network customers have access to an adequate negotiation framework to ensure a reasonable outcome for both parties is achieved. A similar issue arises for the negotiation of prices for negotiable service (excluded services and higher than normal levels of prescribed services), for which clause 6.5.9 establishes a negotiation framework. Negotiation frameworks under clause 6.5.9 are required to specify:

- that parties negotiate in good faith;
- that the TNSP must provide commercial information reasonably required to engage in effective negotiation;
- that the TNSP must identify costs of providing negotiable services and demonstrate charges relating to those services reflect these costs;
- a reasonable time period for commencing, processing and finalising negotiations;
- a process for dispute resolution;
- a requirement to publish to outcome of the negotiation; and
- arrangement for payment by the network user of the TNSPs reasonable direct expenses in processing the application for negotiable services.

The Commission considers that such a framework is necessary to address the concerns that monopoly TNSPs may be in a stronger bargaining position than network users. Requiring TNSPs and network users to follow a specified framework in negotiations, including provisions for information disclosure goes some way to alleviating concerns that negotiations may not take place due to a lack of incentives for TNSPs to do so.

In section 7.2 of this determination the Commission has made it a condition of authorisation that the negotiating framework in clause 6.5.9 of the code should be broadened so that it encompasses discounts to general charges and common services charges negotiated under clause 6.5.8.

In its submission following the release of the draft determination, the NEDF expresses concern that the discounting arrangements would lead to information asymmetry in favour of customers. Customers would know the floor for discounting was the usage price and would seek discounts to that level. The TNSP would be unable to objectively evaluate any claim by the customer that the full price would lead to the business choosing not to connect to the network. The Commission accepts that this concern is valid and that there is a broad principle involved: negotiations should be on a basis of full and symmetric information. The Commission has therefore extended the negotiating framework to require network users to disclose information that is essential to the negotiations. This issue is discussed further in section 7.2 of this determination.

*Information disclosure*

The Commission considers that in instances where negotiated price discounts are recovered from customers, they have a right to know the details of the additional costs they will bear. However, the Commission notes the SA Treasury's argument that releasing details of a specific network user's negotiated discounts may provide the network user's competitors with commercially sensitive information. The Commission agrees that commercially sensitive information should not be made public. The Commission has imposed a condition of authorisation (C4.22) that TNSPs must provide the Commission with detailed information regarding all negotiated price discounts for individual customers, and the proportion of costs proposed for recovery from other network users. This information should be included in the TNSP's annual compliance statements to the Commission. The Commission must then be able to publish aggregate information about transmission charge discounts for each TNSP, maintaining the confidentiality of any commercially sensitive information.

The Commission considers the identification of each of the transmission charges is necessary to facilitate the negotiation of discounts on the TUOS general charge and common services charge. The Commission notes that the requirement under the code for TNSPs to publish network charges does not require the separate publication of the various classes of charge. In section 8.1 of this determination, the Commission has imposed a condition of authorisation requiring TNSPs to separately publish the TUOS usage, general charge and common service charges.

The Commission considers that within this framework network users should be able to determine each component of their total transmission charges, including the usage charge, the general charge, the common service charge and any increases in general charges or common service charges due to discounts offered to other network users.

*Drafting errors*

The proposed changes to clause 6.5.8 of the code provide that negotiated reductions in *customer transmission use of system* prices are recoverable from other customers. The Commission considers that only those discounts negotiated in respect of the TUOS general charge or common service charge should be recoverable from other customers. To reduce any ambiguity this concern is addressed in condition C4.15.

### 4.5.5 Conditions of authorisation

**C4.15 The code (including clause 6.5.8) must be amended to require that where a TNSP agrees to a discounted charge the TNSP may only recover the amount of the discount from other network users provided the discount relates to a general charge or a common services charge and the TNSP demonstrates to the ACCC's satisfaction that the discount complies with the ACCC's Guidelines for the Negotiation of Discounted Transmission charges.**

**C4.16 The code must be amended so that the regulator, when setting a revenue cap for a Transmission Network Owner and or Transmission Network Service Provider, must have regard to circumstances where the costs of discounts have been recovered from other network users, despite the discounts not satisfying the ACCC's Guidelines for the Negotiation of Discounted Transmission charges.**

**C4.17 The code must be amended to require TNSPs to seek approval from the Commission for the recovery of the costs of discounts offered prior to the promulgation of the Commission's Guidelines for the Negotiation of Discounted Transmission Charges.**

**C4.18 Proposed clause 6.5.8(d) must be deleted.**

**C4.19 Proposed clause 6.5.8(c) must be deleted from the code.**

**C4.20 Clause 6.5.8 must be amended to replace references to a *Code Participant* with references to a *Network User*.**

**C4.21 Clause 6.1.5(b) must be deleted.**

**C4.22 The code must be amended to require TNSPs to include information on negotiated transmission price discounts in their annual compliance statements to the regulator. The TNSPs' annual compliance statement to regulator must clearly set out the discounts issued to each customer, the amounts to be recovered from remaining customers, and substantiate any claims for confidentiality.**

**The code must be amended to allow the regulator to publish aggregate information on the price discounts offered in accordance with clause 6.5.8 and the proportion of revenue to be recovered from other network users.**

## 4.6 Financial transfers between network service providers

Under the existing code, financial transfers amongst TNSPs are governed by clause 6.7.4, supplemented after January 2001 by the provisions contained in clause 6.7.3. Authorisation is being sought for proposed changes to clause 6.7.4.

The proposed changes to clause 6.7.4 set out that each regulated TNSP will allocate the costs of its transmission network and that some costs may as a result be allocated outside its own network. The changes allow for financial transfers so that each TNSP can recover the allocated costs from neighbouring regulated TNSPs. The implication is that the neighbouring TNSPs will adjust their cost allocations so as to recover the additional costs from their own users, or from more distant TNSPs. MNSPs are liable for negotiated charges but are otherwise exempt from this financial reconciliation process. Costs of new small transmission assets allocated to generators are not to be transferred across region boundaries. There is also to be an embargo on transfers of transmission general charges until a review by NECA prior to 2001.

### 4.6.1 What the interested parties say

BDB, National Grid International Limited (National Grid) and TransEnergie note that clause 6.7.4 introduces ambiguity regarding whether or not MNSPs have to pay TUOS usage and common services charges. National Grid argues the clause should be amended to make clear that (consistent with clause 5.5A(g)(2)) an MNSP pays only negotiated use of system charges and not Customer TUOS usage or common service charges.

Both Powerlink and the NSW Treasury express concern that interested parties were not consulted on the proposed changes to clause 6.7.4. They suggest that at a minimum, the proposed changes should be investigated further and discussed with affected parties before a final decision is made.

### 4.6.2 What the applicant says

NECA notified the Commission that there is an error in clause 6.7.4(c)(2). The clause should read as follows:

> In determining the financial transfers there will be no allocation of Customer TUOS general charge to the connection points of Market Network Service Providers, which connection points will only be charged any negotiated use of system services charges and charges for entry and exit services where applicable.

### 4.6.3 Issues arising from the draft determination

In its draft determination the Commission imposed the following conditions of authorisation:

**C4.18 Clauses 6.7.3 and 6.7.4 of the code must be amended to achieve the following effect:**

1. **TNSPs must notify NEMMCO of transmission usage charges and rebates that they are expect to receive and pay, based on the application of published transmission usage prices;**

2. **NEMMCO must compute the net amount to be retained by each TNSP according the formula published be NECA in accordance with condition 5.3;**

3. **NEMMCO must invoice TNSPs who over-collect and then pay those who have under-collected.**

**C4.19 Clause 6.7.4 of the code must be amended to require NECA to consider the option of NEM-wide general charges as part of its review of the inter-TNSP allocation of general charges. The code must also be amended so that this review is to be completed by 30 June 2001.**

NEMMCO comments that while it did not seek the role proposed for it in relation to transmission pricing and inter-TNSP settlement, it understood the rationale for the appointment of a body independent of the TNSPs to calculate and administer TUOS prices on a consistent national basis.

The NEDF considers that the billing arrangements for TNSPs are relatively straightforward and do not require central settlements by NEMMCO. It recommends however that within a region the transmission pricing arrangements should deliver outcomes that are independent of asset ownership, which would require all components of the transmission charge to be treated on a whole-of-region basis.

TransGrid queries whether NEMMCO was the most appropriate body to apply and administer usage pricing, suggesting that alternatives such as the IRPC or a coordinating committee of TNSPs should be considered.

QLD Treasury is concerned that the changes proposed by the Commission could lead to financial flows across the NEM that have not been quantified and which could have a consequential impact on Queensland customers, the Queensland Government (if tariff support was necessary) and market participants. On the other hand, it is concerned that the costs of augmentations in Queensland consequent on Directlink could be unfairly borne solely by customers in Queensland irrespective that both NSW and Queensland customers can benefit from the MNSP’s existence.

### 4.6.4 Commission’s considerations

Financial transfers will impact on the efficiency and consistency of transmission prices across the NEM. If properly implemented the provisions for financial transfers could provide significant public benefits.

*Financial transfers relating to TUOS usage charges*

Under the proposed code changes, each coordinating TNSP would compute usage charges for its region, including connections to downstream regions. Each TNSP would bill its neighbouring downstream TNSPs annually, based on estimated flows between them. The resultant financial transfers would be taken into account by each

TNSP when setting its general charges, so that the required total revenue was still recovered. These provisions ensure that any customers of neighbouring TNSPs who are identified as users of an asset contribute to its revenue requirement. However they make their contribution via increased general charges, rather than usage charges, and thus do not receive appropriate usage signals. In contrast, the present code arrangements permit usage pricing to reflect upstream and downstream network use and sanction corresponding financial transfers between TNSPs. As a result it is currently possible, but not mandatory, that all customers identified as users of an asset will contribute to its revenue through the payment of usage charges. The Commission considers that the existing arrangements which allow price signals to network customers result in a potentially more efficient outcome than the proposed code changes. Consequently, the Commission is imposing a condition of authorisation (C4.24) that the proposed changes be deleted.

Ultimately it could be desirable from the viewpoint of both efficiency and equity to have a NEM-wide arrangement for revenues from TUOS usage charges to the relevant asset owners, thus implementing a user-pays approach to the existing transmission network. The Commission is imposing a condition (C4.25) that NECA consider this in the course of the review referred to below.

*Financial transfers relating to TUOS general charges*

The role of the TUOS general charge is to recover the balance of the required revenue from network users without distorting their market behaviour. Hence it will be beneficial for the general charges to be applied uniformly over as wide an area as possible in order to avoid distortion at regional boundaries.

Both the existing and amended financial transfer provisions allow for general charges to be made uniform within each region. The existing arrangements also permit uniformity to be achieved over wider areas, where agreed by all NSPs concerned. The amendments would allow inter-regional transfers (following a NECA review), but do not guarantee price uniformity. Thus it is not clear that the proposed amendments will deliver material benefits relative to the present arrangements.

Ultimately it could be desirable from the viewpoint of minimising distortion to apply general charges uniformly across the entire NEM. In time, the commission considers that given consistent regulation and asset valuation there may be some benefit in moving towards price uniformity. However the imposition of a globally uniform price at this time might result in inappropriate wealth transfers, due to inter-jurisdictional variations in asset valuation methodologies.

The Commission notes that a proposed amendment to clause 6.7.4 requires NECA to review the inter-regional transfer of general charges. The Commission has made it a condition of authorisation (C4.24) that NECA must consider the question of uniform NEM-wide general charges as part of that review. The Commission notes that the review was due to be completed by 1 January 2001, being the date at which clause 6.7.3 was due to commence operation. Given this review has not been conducted, this date should be extended. The Commission proposes an extension until 1 July 2003, to allow sufficient time for the review to take place. The Commission notes that the provisions of the code dealing with inter-regional residues will expire on 1 July 2002 (clause 3.6.5). Inter-regional residues are effectively a form of inter-regional financial transfer and hence the review should also consider the treatment of inter-regional residues. Consequently the Commission considers the expiry date of the clause 3.6.5(a)(5) should also be extended to 1 July 2003.

The Commission also has concerns about whether the code changes adequately address the issue of the transfer of general charges when there are multiple TNSPs within a region. The Commission therefore recommends that NECA's review also consider this issue.

### 4.6.5 Condition of authorisation

**C4.23 The proposed changes to clause 6.7.4 must be deleted, except for retaining the possibility of transfers arising in the future from the application of a revised version of schedule 6.8, the requirement for NECA to review the inter-regional allocation of general charges and extension of the reference to clause 6.4.3 to include 6.4.3A, B and C.**

**C4.24 Clause 6.7.4 must be amended such that the terms of reference for the review must include:**

**(a) the option of NEM-wide general prices;**

**(b) NEM-wide transfers relating to usage charges to implement a "user pays" approach to the existing transmission network; and**

**(c) the provisions for the distribution and allocation of inter-regional settlement residues;**

**The completion date for the review, the date of commencement of clause 6.7.3 and the date of cessation of clause 3.6.5(a)(5)(ii) must be changed to 1 July 2003.**

# 5. Distribution network pricing

This section considers NECA's recommendations of a move to a nationally consistent approach to distribution pricing. Other distribution pricing issues such as:

- negotiation arrangements for above prescribed levels of distribution network services;
- unbundling TUOS and DUOS charges;
- the pass through of TUOS savings associated with embedded generation; and
- a beneficiaries pay approach to new investments;

are considered in chapters 6 to 9 of this determination.

## 5.1 Issues for the Commission

The code's network pricing arrangements are a key component of the NEM design and impact on the ability of the code to deliver public benefits through efficient utilisation of and investment in network assets as well as optimal electricity production and consumption decisions. An effective access regime is also essential to the realisation and pass through of the benefits of upstream and downstream reform and competition.

The transmission and distribution networks are traditionally considered to be natural monopolies, however, alternatives to network facilities exist in some situations, such as embedded generation and demand side management. The code's network pricing arrangements will impact on the ability of non-network alternatives to compete effectively with TNSPs.

The Commission is of the view that network pricing arrangements should be designed to reflect the extent of congestion or spare capacity at different points on the network so as to provide effective market price signals for:

- use of existing network facilities;
- network augmentation or investment in alternatives in congested parts of the network; and
- location of generation, MNSPs and load in areas that do not increase the congestion on network assets.

It is important that any signals arising from transmission prices are transferred through to end use customers and are not distorted by the distribution pricing arrangements.

## 5.2 What the interested parties say

Most parties agree that there is a need to develop a nationally consistent framework for distribution pricing arrangements, although some express reservations about the likelihood of this occurring, stating that any guidelines would be general and broad at best. However, others contend that it would be preferable to provide the jurisdictional regulator with a degree of flexibility, if not control, over distribution pricing.

The AGO contends a consistent national approach to cost recovery is required. Further while the flexibility of the jurisdictional regulators may impinge on the strict application of the principles emerging from NECA's review, insufficient emphasis has been placed on the question of economic feasibility of the recommended changes.

The BCA ERTF contends that a consistent and uniform approach to distribution pricing is desirable given that it will reduce uncertainty, confusion and transaction costs. The BCA ERTF also notes that IPART has established a distribution network pricing principles working group and suggests that the Commission and State regulators should participate in this group.

EnergyAustralia states that NECA's review failed to review the methodologies and the appropriateness of the pricing approaches applying to distribution networks, as required by the code. In addition EnergyAustralia notes that as an owner of both transmission and distribution assets, it would support and participate in the development of consistent national guidelines for distribution network pricing.

The AEA suggests that as NECA's review did not produce a nationally consistent approach, the Commission should develop national guidelines for distribution pricing.

The NSW Treasury considers that a uniform approach to the development of national principles for distribution network pricing is desirable and agrees that jurisdictional regulators should undertake this task as a matter of priority.

The EMRI does not believe that providing a degree of flexibility to the jurisdictional regulator weakens the applicability of the emerging principles, stating that the jurisdictional regulators have demonstrated that they are well attuned to the specific circumstances of their respective jurisdictional network systems and the interests of customers.

The SA Treasury supports the views expressed in NECA's review that jurisdictional regulators should have legitimate discretion over distribution pricing. It also argues for a clear delineation between the respective domains of the jurisdictions and national administrators. However, it acknowledges the difficulty of developing national guidelines, stating that the development of any guidelines will be very general and broad.

Several Vic DBs support NECA's proposals, however, they argue that distribution pricing is a matter for jurisdictional regulators. They further contend that this approach best captures the specific characteristics of each jurisdiction and respects transitional arrangements supported by jurisdictional regulators.

Several Vic DBs and the AEA both support the use of a demand-based component within DUOS as a mechanism to encourage demand side management and enhance network efficiency. However, EnergyAustralia contends that based on its experiences, NECA's recommendation of a significant demand charge is unsound.

TransGrid notes that it does not have strong views on the distribution pricing structure set out in the proposed code changes, however, it believes that NECA's review did not systematically address the fundamental differences between transmission and distribution networks. TransGrid contends that it is essential for these differences to be reflected in the pricing methodologies developed under the code.

### 5.3 What the applicant says

NECA believes that jurisdictional regulators should have the overall discretion to determine the structure of distribution charges, however, it urges them to include a substantive peak demand-based component in these changes. NECA also suggests that the jurisdictional regulators should consider a coordinated approach, which would include the structure of the substantive peak demand-based element, through the regulators' forum. However, despite these recommendations, NECA did not propose any such code changes.

### 5.4 Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

**C5.1 The code must be amended to require DNSPs, where practicable, to allocate TUOS prices to distribution users in a way that preserves the economic signalling of the TUOS prices.**

Ergon supports the principle of condition C5.1 and considers that without a specific requirement for jurisdictional regulators to recognise and drive TUOS signalling, there is a risk that the implementation of the concept nationally will be slow and disjointed.

The NEDF broadly supports national arrangements for distribution pricing where these result in a streamlining of regulatory compliance obligations and do not result in unduly prescriptive or intrusive regulation being imposed on distributors. The NEDF states that any such national arrangements will need to be developed in consultation with affected participants and in cooperation with the jurisdictional regulators.

QLD Treasury contends that distribution pricing is a matter for jurisdictional regulators and does not support any move by the Commission to codify the principles of distribution pricing. QLD Treasury believes that it is unlikely that the legitimate policy interests of individual NEM jurisdictions will be able to be met on a national basis.

QLD Treasury and SA Treasury submit that it is unlikely that small customers would be able to adjust their behaviour in response to locational TUOS signals included in DUOS charges. QLD Treasury believes it is unlikely to result in significant public benefit through more efficient network investment and therefore does not support this recommendation and requests that the Commission removes the requirement for DUOS to reflect transmission pricing signals from the final determination. SA Treasury recommends that the Commission clarify the term 'where practicable' to mean large customers, such as those greater than 10MW or 40GWh per annum, which are able to respond to any economic signal.

Several Vic DBs are concerned about the possibility of inefficient duplication and increased costs arising from parallel State-based and national regulatory regimes for distribution pricing and access and reiterate their desire to see that regulatory policy development takes place in an efficient, coordinated, and consultative manner. Several Vic DBs believe that any proposals to change the present Victorian distribution pricing and access arrangements should be sanctioned by the ORG after appropriate consultation, and proceed only if they are in the public interest.

NECA states that the Commission needs to clarify the proposed requirement for distribution use of system charges to reflect the economic signalling of transmission prices. NECA contends that this objective as an additional principle for distribution pricing on its own, however, is likely to have little or no effect.

### 5.5 Commission's considerations

*Consistency of distribution pricing arrangements*

While NECA's review predominantly focused on transmission pricing issues, the code also required NECA to examine the appropriateness of the methodologies and regulatory principles governing the setting of distribution prices. NECA's review of the distribution pricing arrangements was conducted in the context that most States have currently derogated away from the code's distribution pricing principles and that the code provides scope for the jurisdictional regulators to formulate guidelines for distribution pricing.

The Commission considers that there will be substantial public benefits if a nationally consistent approach is developed for distribution pricing. The Commission notes that there is a growing consensus among jurisdictional regulators to undertake a nationally consistent approach. One of the steps taken by the regulators, as noted by the BCA ERTF, includes the establishment of the NSW based Distribution Pricing Principles Working Group, which consists of representatives from network customers, retailers, distribution businesses, other jurisdictional regulators and the Commission. In light of the current work, the Commission, therefore, considers that the development of a nationally consistent approach be left to the jurisdictional regulators, rather than the regulators' forum. It would also be up to the jurisdictional regulators to determine whether to adopt NECA's proposals for a substantive peak-demand based element.

The Commission recognises that the effectiveness of the price signals that end users see may be blurred because of the method used to structure DUOS charges. The Commission considers that the structure of DUOS charges should be refined to enable the location and time signals of the transmission pricing regime to be fully passed through to those customers who are able to respond to them. However, the Commission disagrees with the comments made by the SA Treasury and Qld Treasury that small customers are unlikely to adjust their behaviour in response to price signals. The Commission cites as an example the existence of off-peak hot water tariffs, which many domestic customers have responded to. The Commission also notes that in aggregate small customers can have as great an effect as large customers. The Commission has therefore made it a condition of authorisation (C5.1) that DNSPs must allocate TUOS charges to distribution users, who have a metering installation that is capable of capturing relevant transmission and distribution system usage data, in a way that preserves the economic signalling of the TUOS prices.

*Negotiating price discounts*

Clause 6.14.6 allows for DNSPs to negotiate price discounts with their customers, but does not specify any provisions for recovering those discounts from other customers. The Commission notes this inconsistency between the transmission and distribution pricing arrangements and recommends that it be addressed by NECA in the future.

*Other issues*

Clause 6.14.6(d) of the code changes requires the regulator to have regard to the potential loss of revenue for the DNSP that could result from the network being bypassed. The Commission considers that this clause is redundant, as bypass should only occur when economically justified. Further, the Commission considers that DNSPs should not be protected from the risk of asset stranding due to a customer bypassing the network and considers that this clause is inconsistent with the optimised depreciated replacement cost approach that the Commission uses to value transmission assets. The Commission has imposed a condition (C5.2) that clause 6.14.6(d) be deleted.

The Commission is also concerned that clause 6.14.6 uses the term *Code Participant* and hence would not allow consumers who do not purchase through a retailer or the spot market to negotiate discounted charges with the DNSP. The Commission has therefore imposed a condition (C5.3) that this clause be amended to refer to a *Network User*.

### 5.6 Conditions of authorisation

**C5.1 The code must be amended to require DNSPs to allocate TUOS usage charges to distribution users, who have a metering installation that is capable of capturing relevant transmission and distribution system usage data, in a way that preserves the economic signalling of the TUOS usage prices.**

**C5.2 Clause 6.14.6(d) must be deleted.**

**C5.3 Clauses 6.14.6 must be amended to replace the references to *Code Participant* with references to *Network User*.**

# 6. Network planning and augmentation

## 6.1 Development of networks within a region

Clause 5.6.2 of the code requires NSPs to conduct planning reviews annually. Where the analysis indicates that a network's technical limits will be exceeded, the NSP must identify options for corrective action. The NSP must carry out a cost effectiveness analysis to determine the option that satisfies the regulatory test while meeting technical requirements. It must then consult with relevant code participants and interested parties on the options, prepare a report on its preferred proposal and resolve any consequent disputes before proceeding with the project.

Under proposed changes to clause 5.6.2, an NSP can only consult in relation to network options which it determines satisfy the regulatory test, and does not need to consult where a generator or an MNSP has agreed to meet all applicable use of system service charges or where a small network asset is involved. For network options, the NSP will be required to determine which market participants are likely to benefit. A further amendment clarifies that the clause will not apply to MNSPs.

Network planning and development issues are also the subject of a review currently being conducted by NECA, and the Commission understands that further code change proposals are likely to arise out of that process.

### 6.1.1 Issues for the Commission

Electricity networks are the vehicles through which producers and consumers trade in the NEM. Under-development of the network can constrain trade and may increase the opportunities for the exercise of undue local market power. On the other hand, over-development of the network may give advantages to remotely located producers and result in more cost-effective demand side options and local generation being overlooked. Network development must represent the optimal solution if it is to deliver public benefits in the form of greater market efficiency.

### 6.1.2 What the interested parties say

The AEA argues that clause 5.6.2 needs to be clarified so that the planning, consultation and assessment of demand side management and local generation options apply equally for TNSPs as well as DNSPs. The AEA is concerned that this clause could be interpreted as applying to DNSPs only as so far as the proposed network augmentation was a result of joint planning with the TNSP. The AEA believe that the regulatory requirements for proposed augmentations will prevent the creation of regions.

The AGO has concerns with the process of examining options where NSPs devise, assess and then recommend options for network expansion and augmentation. To improve competitive outcomes, the AGO recommends that this process include open competition, (or some independent assessment) to augment regulated networks, install embedded generation or increase efficient energy usage to ensure that only the most technically and economically feasible options are considered.

The NGF is concerned that the proposed code changes in clause 5.6.2(f) do not provide for an NSP to engage in any form of consultation with regard to new small assets. In order to avoid scrutiny over new network investments the NGF argues TNSPs will break down larger projects into smaller components in order to circumvent the entire negotiation and consultation process associated with large new investments.

National Grid suggests that clause 5.6.2(f) should recognise the presence of entrepreneurial interconnectors in the electricity market and that NSPs should be required to also consider implementing a market network service option.

### 6.1.3 What the applicant says

With regard to network planning, NECA states that its preference is for future new network investments to be undertaken on a non-regulated, market basis, so far as possible. NECA made no specific comments in regard to proposed changes to clause 5.6.2(f).

### 6.1.4 Commission's considerations

The present code provisions require NSPs to consult on all identified options for addressing a projected limitation in the transmission or distribution system. However, the proposed changes to clause 5.6.2(f) of the code confine the consultation to options that an NSP had determined satisfied the regulatory test. One objective of the consultation process should be to find information relevant to the regulatory test, thus helping to ensure the test is applied validly. Narrowing the scope of the consultation may reduce its effectiveness in that regard.

The changes to clause 5.6.2(f) also remove the requirement for an NSP to consult where a generator or an MNSP agrees to bear all applicable use of system service charges. However, augmenting the network can sometimes affect the useability of other parts of the network and thereby impact negatively on other network users. The Commission therefore considers that it is inappropriate to exempt NSPs from the requirement to consult just because an MNSP or generator agrees to bear all of the applicable use of system service charges.

Given the above concerns and the fact that the network planning and development provisions are currently the subject of further review by NECA, the Commission does not consider it appropriate to authorise the proposed changes to clause 5.6.2(f), and has imposed condition C6.1, accordingly.

### 6.1.5 Condition of authorisation

**C6.1 Clause 5.6.2 must be amended to ensure that the consultations to be undertaken by a network service provider:**

- **(a) are not limited to only those options that satisfy the regulatory test; and**

**(b) must be undertaken even where a generator or MNSP agrees to bear all of the applicable costs of a proposed augmentation.**

## 6.2 New investments – beneficiaries pay

The proposed code changes provide that in the future all beneficiaries of a new investment in the transmission and distribution networks will contribute to that investment in proportion to their estimated share of the benefits. Further, the proposed changes provide scope for the beneficiaries of new investments to agree to the appropriate sharing of the costs of the investments.

The code changes set out a framework where, as part of the investment assessment process for new investments (larger than $10 million), NSPs are required to assess and consult on the relative benefits to generators and other network customers and allocate costs accordingly. This is done by extending the analysis NSPs already carry out to ensure that a proposed investment satisfies the regulatory test. The extended analysis will identify benefits accruing to each individual generator and to customers as a class as a basis for determining the allocation of costs for the proposed investment. In the event of a dispute, the parties can seek recourse through the code dispute resolution procedures. For smaller investments, the NSP must determine the benefits accruing to network customers and generators as a class and allocate costs on this basis.

### 6.2.1 Issues for the Commission

The proposals to allocate network costs using a beneficiaries pays methodology are a significant change from the current arrangements and will impact on the balance of public benefit and anti-competitive detriment.

### 6.2.2 What the interested parties say

*Implementation issues*

TransGrid argues that the proposed code changes will not introduce more market discipline into the network planning process. While the concept of allocating charges in accordance with the benefits derived is theoretically sound, TransGrid submits that there will be enormous difficulties in both quantifying the amount of benefit received by a particular generator and reaching agreement whether such benefit has been received by a particular generator.

TransGrid, ElectraNet, VENCorp and the NSW Treasury have concerns that the code changes do not specify how the benefits from an investment are to be calculated. VENCorp contends that this appears to leave TNSPs with total discretion as to how to calculate beneficiaries including the option of not using pool modelling at all. While VENCorp does not necessarily oppose this level of flexibility, it does consider that if this was not the intention of the code changes, then specific reference to extending the pool modelling and other specific guidelines need to be included in the code.

ElectraNet and TransGrid consider that the basis for determining the beneficiaries of new network investment and calculating the benefits they receive should be specified in the code. TransGrid contends that this will both reduce the ability of generators to game the identification of beneficiaries and reduce the need for recourse to dispute resolution mechanisms by making the process for identifying beneficiaries more transparent.

TransGrid, the SA Treasury, the AEA, EnergyAustralia and Ergon all have concerns that there will be a reluctance on the part of individual participants to disclose the benefits they receive from new investments so as to avoid having to contribute to the costs. They also argue that there is the potential for gaming the modelling that is used to assess the level of benefits.

The SA Treasury and the AEA further argue that generators and TNSPs will be able to put more resources into presenting their case to the detriment of the customers, who do not have the same level of resources. The AEA suggests that there should be a customer representative body that negotiates on behalf of the customers.

Stanwell expresses concern about whether the definition of beneficiaries under the proposed code changes recognises the potential benefits associated with embedded generation projects.

The NSW Treasury, ElectraNet and Ergon argue that the process does not recognise the dynamic nature of the market and as a result may not deliver stability in the estimated benefits of individual parties or network prices. Powerlink argues that generators will be reluctant to agree to pay TUOS for the life of an investment when its benefit may be eroded or reversed by a later new entrant.

ElectraNet, Powerlink, TransGrid, EnergyAustralia and the NSW Treasury all raise concerns that the pool modelling used to determine the benefits of individual participants will be complicated, costly and will lead to disputes. This is because the assessment of the relative benefits will vary depending on assumptions about operating conditions, bidding strategies, participant’s costs and new generation developments. Powerlink states that their experience shows that under one scenario upstream generators may be beneficiaries, however, under another scenario they may be losers.

Similarly, ElectraNet argues that the assessment of the relative benefits of new investments will vary widely with changes in daily and seasonal operating conditions and is dependant on the market behaviour scenarios considered.

VENCorp argues that while pool modelling can provide reasonably consistent aggregate benefits it can potentially provide dramatically different benefits to individual participants depending upon the input assumptions.

The NSW Treasury argues that studies of a suitably large number of scenarios may produce a statistical distribution of the range of benefits and the likely beneficiaries but in many circumstances it is unlikely to be sufficiently robust to meet with market participants’ acceptance or approval. The NSW Treasury argues that this will inevitably lead to disputes and attendant, undesirable transaction costs.

ElectraNet notes that the proposed framework is so far untested and recommends further analysis of its application to recent real life examples before a commitment is made to its implementation.

*Dispute resolution*

Powerlink, ElectraNet and EnergyAustralia argue that the beneficiaries pay process is likely to result in a protracted dispute resolution process and delayed investment. Powerlink and ElectraNet further contend that there are substantial incentives for those identified as 'losers' in the beneficiaries pay process to delay investments - not on the grounds of benefits versus costs, but on the basis of the allocation of the costs to beneficiaries.

TransGrid and Powerlink also consider that any process for the determination of who should bear the costs of an investment should be separate from the process of determining whether an investment should proceed. Powerlink suggests that once an investment passes the regulatory test the proponent should be allowed to commence the project thereby ensuring the earliest delivery of benefits, whilst at the same time undertaking the beneficiaries pay exercise. Powerlink contends that the beneficiaries pay process should have a time limit of three months with a default cost allocation (for example, a 50/50 split between generators and customers) in the event that there is not agreement on the identification of beneficiaries. Powerlink also argues that only those participants that are required to pay for the investment should be able to make representations to the TNSP within 40 business days.

VENCorp argues that given the complexities, and to a large extent arbitrariness of attempting to allocate beneficiaries of new investment, consideration should be given to some form of arbitrary allocation of costs of new investment. VENCorp believes that there is the potential to develop an approach that allocates costs based on categories of benefits such as reduction of unserved energy, or reduction in losses. VENCorp considers such an approach would be consistent with the approach for allocation of ancillary services on a 50/50 basis between customers and generators.

The AEA, the SA Treasury and EMRI all argue that the Commission is the appropriate body to arbitrate disputes between networks and network users arising from the beneficiaries pay process, because of its role as the transmission regulator and its role in overseeing the application of the regulatory test.

Ergon argues that the code's dispute resolution procedures will be unworkable for arbitrating a dispute over who pays for new investment. Ergon proposes that the National Electricity Tribunal should be the arbiter.

*Threshold for classification as large or small network asset*

Powerlink argues that the $10 million threshold for new large network assets is too low for the Queensland network because:

- the costs of the beneficiaries pay process will be about $800,000 to $1 million per project and this is a very high administrative overhead to pass on to customers; and

- the only projects that will cause material benefits to generators will be line projects and these projects cost more than $50 million.

Powerlink suggests that the threshold for large investments in Queensland should be $50 million.

Powerlink also argues that the code changes need to be amended to reflect NECA's intent that small investments are not subjected to the costly consultation processes and regulatory tests.

The AEA argues that the consultation and disclosure processes should be undertaken regardless of the size of the new investment. It argues that the different process for small investments reduces transparency, access to information and the opportunities for local generation and demand management. The AEA suggests that the threshold be lower and that it should be subject to a $/kW test linked to the demand or reliability that is being met by the investment.

The NSW Treasury supports the planned distinction between small and large capital investments and adopting streamlined processes for smaller and/or uncontroversial investments. However, the NSW Treasury argues that further consideration might be given to the appropriate threshold by reference to actual project experience of the network businesses and the substantial transaction costs that accrue when applying the consultation processes developed in respect of major investments.

*Date of effect*

The code change proposals define new projects as 'all new investment projects' including those projects 'already included in NSPs capital programs, on which work commences after 1 July 2000.' The SA Treasury states that the term 'work commences' is very broad and may be interpreted to include feasibility or other preliminary studies. The effect of this could be that the beneficiaries pay process may not actually be implemented for at least 10 years because projects planned within this time may have some preliminary work commenced before 1 July 2000 and therefore be classed as sunk costs. The SA Treasury proposes that the definition of new investments be changed to 'any transmission project for which the operational date is after 1 July 2000.'

*Consistency with LRMC principle*

The AEA argues that the proposed beneficiaries pay system, which recoups costs, is inconsistent with Ernst and Young's statement that LRMC sends the correct economic signal. This is because there is an incentive for new generators to locate close to existing generators to share the cost of new infrastructure. The AEA argues that the result of this is that new generators don't necessarily see the LRMC of their investment decision and there may be economically inefficient investments and an incentive for new distant coal fired generation at the expense of embedded generation.

The AEA proposes that generators should pay a proportion of TUOS charges equivalent to the LRMC at that connection point and that in return generators should receive tradeable property rights that cannot be diminished by new connections without compensation.

*Alternative approaches*

SPI PowerNet argues that while the allocation of costs of transmission investments among beneficiaries may sometimes be necessary there is the potential for a largely market driven approach to grid investment based on locational pricing of energy and

Transmission Congestion Contracts (TCCs). SPI PowerNet contends that locational pricing of energy will provide transmission users with an incentive to expand the system when congestion costs become sufficiently high to warrant incurring the costs of investment. Further, SPI PowerNet argues that the assignment of TCCs or TCC options to those who pay for system investments ensures that those financing system investments receive the benefits they pay for.

SPI PowerNet notes that the NECA Draft Report states that:

> the ideal basis for determining the relative beneficiaries from new investment would be precisely to model the behavioural impact of that new investment on market prices over the asset life of the investment. The enormous uncertainties inherent in even attempting such an exercise, however, would make the outcomes both contentious and unreliable.[18]

SPI PowerNet argues that under a market driven system of transmission investment based on TCCs, the investors themselves would make these assessments of future benefits and take their own account of these uncertainties. Thus, short-run pricing signals can provide the basis for both short-run and long-run decision making by generators and loads.

*Other comments*

The NGF agrees that the code changes in general introduce more market-like disciplines into the network planning processes but believes that this depends on a greater alignment and consistency between the ACCC's role and the code's investment process.

The NGF has concerns that efficiency drivers for new investment will be compromised by a process in which either:

- new transmission investment can be included in the revenue requirement without first being subject to the code's investment process; or
- new transmission investment that is subject to the code's investment process does not necessarily receive any applicable revenue requirement through the ACCC's process.

The NGF argues that where an NSP can allocate costs of new investments to alleged beneficiaries arbitrarily (as with new small investments) the NSP is unlikely to reconsider the investment if involved parties argue that their benefits have been incorrectly identified. The NGF suggests that this problem can be addressed by ensuring that:

- the investment process occurs in a commercial setting, including a framework for investor scrutiny and potential participant challenge;
- the investment approval and funding processes are fully aligned with each other; and

18 NECA Draft Report, p. 24.

- consumers are represented in the investment process.

Further, the NGF believes that the use of firm financial arrangements will also introduce more market like discipline to the network investment planning process.

The AEA argues that it is inappropriate for existing generators to receive the benefit of higher spot prices set by new entrants (that reflect the deep connection costs) resulting in a windfall gain to incumbent generators that do not pay any TUOS. The AEA also argues that the code should detail the information that NSPs must disclose so as to enable alternative non-network options to be considered.

SPI PowerNet argues that it is not entirely clear whether replacement of existing capacity is defined as 'all new network investment' or 'large new network investment'. SPI PowerNet argues it will be particularly difficult to implement the proposal in respect of replacement in Victoria because of the separation of responsibilities for transmission where SPI is responsible for maintaining and replacing existing capacity, while VENCorp is responsible for planning the network, directing its investment, and calculating and levying TUOS.

Stanwell argues that NSPs should only be able to obtain regulated status for new investments where both the net benefits and market failure tests have been satisfied with the burden of proof resting on the NSP. Stanwell states that NSPs should seek market based commercial solutions with regulatory intervention considered only as a last resort. Further, Stanwell argues that the framework for determining eligibility for regulated status should be clear and transparent so as to minimise uncertainty and associated regulatory risk, both of which act to deter investment.

TransGrid considers that the proposed code changes create uncertainty for investment in network assets and energy intensive industries because NECA did not address issues such as how NSPs calculate LRMC, how NSPs determine beneficiaries from an investment and the framework for TNSPs to offer discounts.

### 6.2.3 What the applicant says

NECA states that planning of new investment should be required to take account of both generation and demand side requirements as new investment benefits customers through improved system reliability, and new or existing generators through reduced losses or a lower level of constraints.

NECA argues that the mismatch between those who benefit from new investment and those who pay for it is a serious flaw of the existing arrangements, leading to inefficient investment and inappropriate locational signals.

NECA states that the proposed changes are designed to ensure that all the beneficiaries of new investment in the transmission and, where there are shared benefits, the distribution networks, contribute to the cost of that investment in proportion to the estimated share of the benefits they derive from it. NECA argues that by establishing who benefits and in what proportion, implementation of the beneficiaries pay principle for new investment will help to ensure that only efficient investment in the network is undertaken.

NECA further argues that as generators will have a stake in meeting part of the cost of new investment under the proposed arrangements they are likely to act as a brake on inefficient or over investment in the network by acting as a cohesive and coordinated lobby group to ensure future investment programs are properly justified.

By allocating use of system charges for new investment between market sectors in accordance with their relative share of benefits NECA considers that concerns about deep connection are addressed. Specifically, NECA argues that the beneficiaries pay approach addresses concerns that a generator may locate remotely and benefit from new investment without paying for it.

NECA further indicates its preference that, as far as possible, new network investments should be undertaken on a non-regulated, market basis. However, where a project becomes part of the regulated network the proposed changes provide scope for NSPs and the beneficiaries of the project to agree on the need for the investment, and an appropriate sharing of costs. NECA argues that this obviates the need for a contested regulatory process to establish the case for a new investment and is consistent with the principle of seeking outcomes that mirror those that would apply in competitive markets.

### 6.2.4 Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

**C6.2 The proposed framework for the identification of beneficiaries of new investments and the allocation of the costs of new investment to these beneficiaries, broadly termed the beneficiaries pay process, must be deleted from the code.**

The AEA states concern with the Commission's apparent abandonment of the principle that the beneficiary of the investment actually is required to pay for it.

The AGO agrees with the principle that all beneficiaries of a new investment in the transmission and distribution network contribute to that investment in proportion to their estimated share of the benefits. However, the AGO also acknowledges the difficulty in accurately identifying who benefits, to what extent and over what period of time.

The NEDF states that in rejecting the beneficiaries pay concept, the Commission has recognised the unworkability of the arrangements that had been proposed by NECA. The NEDF agrees with this preliminary assessment, noting that NECA is presently undertaking further work to identify a practicable method for implementing the concept.

Enertrade endorses the NGF submission and states that a property rights regime should facilitate new network investment by those who would benefit and minimise the risks of inter-regional trade.

Hazelwood supports the frustration expressed by the NGF with the rejection of the beneficiary-pays approach to new network investment.

Hazelwood believes that while problematic to implement, the beneficiary-pays approach forces networks to evaluate the benefit of their investments in a more transparent way, and to either seek a coalition of commercial interests to support the investment, or make a transparent commitment based strictly on reliability criteria.

Hydro states that there may be a need for re-consideration of the position with respect to the beneficiaries pay process proposed by NECA for new investment. Hydro considers that while the principles identified by the Commission are appropriate for a forward looking pricing regime, they may need to be supplemented by re-introducing the beneficiary pays principle, if a regime is to be designed which also recovers transmission investment costs in an equitable and efficient manner.

InterGen believes the beneficiaries' pays model (in a modified form as proposed by the Newcastle Group) should be evaluated by the Commission when considering the issue of a NEM-wide appropriate regulatory test for new investment. Intergen considers that the regulatory test should be an economically defensible method that maximises net benefits amongst a range of alternatives. To ensure that gaming does not occur a bond of a significant size should be charged to proponents.

Loy Yang states that beneficiaries pays is accepted as a sound principle.

NECA has been conducting further work on the method for allocating the costs of new investments. Their latest proposals would involve a once-off division of costs between customers and generators on the basis of relative benefits as determined by an 'energy deprival' approach, which would assess unserved energy and generator outputs with and without the new investment. Prices to individual generators would then be determined annually using the same network pricing model that emerged as the basis for setting customers' transmission usage charges.

NSW Treasury is of the view that a form of the beneficiary pays proposal for sharing the costs of new network investment could overcome many of the problems associated with the example usage charge methodology included in the draft determination. This is discussed in the Newcastle Group's position paper.

The NGF notes the Commission's acknowledgment of the theoretical soundness of the beneficiaries pays approach. While the NGF acknowledges that the regime has some practical problems it does not believe they are of sufficient concern to warrant rejection of the proposal.

The NGF believes that if the Commission had concern with the beneficiaries pays regime it should have placed a condition of authorisation to specifically examine and correct any shortcomings it identified. The NGF states the outright rejection of this approach is premature. Finally it considers that including a framework of property rights will resolve the issue of beneficiaries changing over time.

NRG Flinders supports the NECA beneficiaries pay regime and cannot find a justifiable reason within the Commission's draft determination for it to be rejected in totality. NRG Flinders states that with the exception of the TNSP's, the pre determination conference showed that the majority of participants preferred the beneficiaries pays approach. NRG Flinders believes that the Commission could have requested that

NECA develop a more robust, clear and transparent methodology for beneficiaries pay to overcome the concerns of the Commission.

NRG Flinders considers that instead the Commission has rejected the beneficiaries pay approach (which was widely consulted through the NECA review) and has replaced it with a TUOS usage charge approach which is not clear nor does it create an efficient mechanism of allocating the costs associated with network assets.

The Newcastle Group states that NECA has suggested that a ‘beneficiary pays’ approach could apply to new investment costs and has proposed various methodologies for the determination of beneficiaries. The Newcastle Group argues that it was pointed out that allocating costs on the basis of expected benefits has little basis in economic theory and that the efficient way to allocate costs is on the basis of who requires that additional costs be incurred – a ‘causer pays’ type of methodology.

The Newcastle Group considers that from an economic efficiency perspective the primary issue is to allocate costs to the party whose decision results in those costs being incurred. In the case of reliability-driven investments, the causers of the investment were clearly customers.

The Newcastle Group believes that in the case of market-benefit driven investments, the causers could be seen, on one level, as the market as a whole. The regulated augmentation proponent (and indirectly the Commission as transmission regulator) makes the decision to impose the costs on the market due to clearly demonstrated net market benefits. In such a case, the Newcastle Group considers that perhaps beneficiary pays could prove a sensible way forward for allocating costs.

Origin supports NECA’s proposal for a methodology of beneficiaries pays to be embodied in transmission pricing and disagrees with the Commission’s decision to delete this provision.

Origin states that if the Commission does not support a form of beneficiaries pays test then there may be a misallocation of resources caused by the masking of financial benefits of those investments which offer cheaper solutions to augmentation. Origin contends that this will act as a disincentive to the provision of least cost investment solutions.

Powerlink supports the Commission’s conclusion that the beneficiaries pays proposal, while economically sound, suffers from an unsound practical application viewpoint. Powerlink considers that it could not support a beneficiaries pays approach until a robust and dispute resistant method is identified. Powerlink supports the deletion of the beneficiaries pays process from the proposed code changes.

QLD Treasury notes that NECA has developed a revised framework in relation to the beneficiary pays proposals and the Commission has sought to delay consideration of this issue until the revised arrangements are developed. QLD Treasury makes no comments on this issue at this point in time but reserves the right to comment in future.

Snowy considers that NECA’s proposal may be useable and meet the principles espoused by the Commission if the beneficiaries pays can be made more workable and transparent and that this can be facilitated through the establishment of some form of firm property rights.

Snowy believes that the Commission’s TUOS proposal may be workable if a robust methodology can be developed that does not significantly distort dispatch and is driven by market based incentives. However Snowy argues that both the NECA and Commission proposals have not adequately addressed the definition and lack of property rights, not created incentives for networks to maintain and improve service and take some form of accountability for market outcomes.

Snowy states that by allocating property rights to investors the issue of changing beneficiaries with time becomes irrelevant. Snowy considers that the beneficiary is basically the owner of the property right and since the property right is a defined quantity it could be traded readily to new beneficiaries who perceive more value in acquiring the property right from the current owner.

Stanwell states that due to the possibility of changing market participants, once augmentation occurs there might be a mismatch between beneficiaries and investors. This problem could be overcome by issuing property rights that can be transferred. Stanwell considers that free-riders will appear as property rights have not been assigned or introduced. To overcome this there should be a requirement for new generators locating in a generation rich area, which has recently undergone augmentation to make an undertaking that would be designed to ensure that the new entrant does not disadvantage those participants who have invested in the augmentation.

Tarong believes that a resolution to the issue of property rights accruing in respect of network access would also assist in allaying the Commissions concern in respect of changes to beneficiaries over time. Tarong states that the Commission is concerned that the proposed arrangements do not include any provision for re-calculation of beneficiaries over time. Tarong believes that the creation of defined rights to receive the services being paid for will allow these rights to be on sold as beneficiaries of that access change over time.

TransÉnergie supports the beneficiaries pays principle, but agrees with the Commission that it is unworkable in its present format. TransÉnergie’s position is that the development of a system of financial transmission rights will eliminate all the problems associated with the beneficiaries pays approach.

TransGrid strongly supports the proposal in the draft determination that a condition of any authorisation be that the proposed framework for the identification of the individual beneficiaries of network investment be deleted from the code. TransGrid supports the Commission’s draft decision to reject NECA’s proposal for allocating the costs of new investment based on a beneficiary pays approach.

VENCorp states that notwithstanding the practical difficulties associated with NECA’s beneficiary-pays proposal, the Commission’s draft determination acknowledges the conceptual merit of the beneficiary pays approach. VENCorp also agrees that the approach has strong merit.

VENCorp also notes that despite the imposition of condition C6.2 (which requires the beneficiaries pay proposal to be deleted) NECA is continuing to undertake further work on the method.  It would therefore seem appropriate for the Commission's final decision to accommodate the possible outcomes of the further work being undertaken by NECA at present.  VENCorp fully supports the development of pragmatic ways of achieving a beneficiaries pays approach.

Western Power considers that if utilisation signals are built into pricing such that the revenue requirement for lightly loaded assets is diminished in order to encourage greater usage, the beneficiaries of new augmentations will not be paying an equitable share of the revenue requirement of the augmentation.  Western Power believes that, on balance, the CRNP method is to be preferred to other methods proposed so far which introduce other problems.  Western Power recommended that the Commission retain the CRNP method as the basis for calculating TUOS usage prices.

### 6.2.5 Commission's considerations

The Commission considers that regulated outcomes should, to the extent possible, mirror the outcomes of competitive markets.  As noted by NECA, both customers and generators benefit from network investment through either improved system reliability or reduced losses and lower levels of constraints respectively.  The current mismatch between those who benefit from a new investment and those who pay for it can lead to inefficient investment and inappropriate locational signals.

The Commission agrees with the principle that those who benefit from a new network investment should bear the cost of the investment in proportion to the benefits they receive.  Allocation of costs on the basis of beneficiaries pay will ensure appropriate investment signals and mirror the outcomes of a competitive market.

However, the Commission also agrees with the concerns expressed by several interested parties that while the principle of beneficiaries pay for new investment is theoretically sound the proposed process will be difficult and contentious to implement, and may not deliver the expected benefits.

*Identification of beneficiaries.*

The Commission notes that the proposed arrangements provide little guidance about how beneficiaries are to be identified, either collectively or individually.  The code changes merely stipulate that each NSP must extend the analysis outlined in clause 5.6.2 to estimate the benefits which generators as a class derive from a new (large) network investment as a percentage of the overall benefits of the investment.  From this estimate the NSP is required to determine the proportion of benefits to be allocated to each individual generator, with the remaining benefits deemed to accrue to all other users of the relevant network.

The Commission considers that potential beneficiaries may have an incentive to understate the benefits accruing to them from new network investments in order to reduce or avoid bearing a portion of the cost of proposed investments.  This could lead to inappropriate cost allocation, and in the extreme, jeopardise new investment taking place, unless some default rule is in place.

It is also apparent that estimates of the beneficiaries of new network investments will vary considerably depending upon assumptions about market behaviour (including bidding strategies), new generator developments, generator variable costs, forced outage rates, and daily and seasonal operating conditions. The Commission therefore expects that the calculation of beneficiaries will be arbitrary, with the results susceptible to dispute by affected parties.

The Commission considers that the lack of incentives for network users to identify themselves as beneficiaries once new investments have been committed necessitates a rigorous and transparent methodology, which specifies how the beneficiaries of proposed investments will be identified.

Codifying a specific methodology would provide guidance to NSPs that must identify beneficiaries, as well as reducing the likelihood of disaffected parties commencing dispute resolution procedures. The development and testing of a methodology prior to codification also allows for analysis of the results prior to implementation.

The Commission considers that the proposed arrangements, whilst theoretically robust, have serious flaws in terms of ensuring such a methodology is used.

The Commission supports Powerlink's suggestion that where agreement on the identification of beneficiaries cannot be reached, the code should provide for a default cost allocation. This is necessary:

- to address concerns that the proposed framework, which is as yet untested will not be able to accurately identify beneficiaries; and
- because the ambiguity surrounding the proposed process leaves decisions made regarding beneficiaries open to dispute.

Provision for default cost allocation in the event that agreement as to beneficiaries cannot be reached would ensure an outcome for the allocation of the costs of new investments.

The Commission considers the absence of provisions for default cost allocation a serious flaw in the proposed arrangements and does not consider the beneficiaries pay process workable without such provisions. Such a default rule could provide for a 50/50 cost allocation between generators and customers. Further, the Commission notes that if the beneficiaries pay cost allocation can be expanded to include effective property rights, then it could be expected that beneficiaries may voluntarily come forward, in order to access the property rights.

*Changes to beneficiaries*

The beneficiaries pay principle is intended to ensure efficient investment and mirror the outcomes of a competitive market by alleviating the current mismatch of those who benefit from a new investment and those who pay for it. However, the Commission considers that the lack of a provision in the proposed arrangements for the re-calculation of beneficiaries means that, even assuming that beneficiaries are correctly identified in the first instance, the mismatch of those benefiting and those paying for a new investment may reassert itself over time. This may occur through participants entering or leaving the market or the benefits to incumbent participants changing over time.

The Commission considers the lack of provisions for re-calculating beneficiaries in response to changed market conditions may also lead to inefficient pricing signals. For example, the potential exists for inefficient entry and locational decisions as new connectees could benefit from an existing investment, where beneficiaries have already been identified, without having to carry a portion of the costs.

It is therefore likely that identified beneficiaries will be reluctant to bear the cost of new network investments where there is the possibility of such benefits being eroded or reversed by potential new entrants who do not contribute to the cost of the assets. Similarly the code changes do not provide for reimbursing market participants who pay for a new investment and then leave the market without accruing all of the benefits they have effectively paid for.

The Commission is also aware that even without considering market entry or exit, it is still unlikely that the beneficiaries of a proposed investment will be stable overtime. For instance, circumstances could arise where customers receive system security benefits early in the life of a new investment. However, that same investment could also provide additional power transfer capability that might not be reflected as a benefit to generators until later in the life of that investment[19]. Alternatively, it could be anticipated that benefits, which are identified at a particular point in time, might not always accrue to the same individual. For instance, while a number of generators may benefit from a new network investment through the removal of constraints or reduction in loss factors, this benefit could be transferred to customers if the investment facilitated competition between the generators leading to a reduction in the spot prices.

Addressing the issue of changing beneficiaries requires some process whereby the beneficiaries of an investment can be identified through time. However, the Commission notes that if the beneficiaries pay process were open to re-calculation over time there is a problem of how often to undertake re-calculation of beneficiaries. Frequent reassessment would be impractical and impose significant administrative costs on the market and lead to unstable network prices. Conversely infrequent reassessment would mean that those benefiting later in the life of a project would effectively be free-riding on those identified initially as beneficiaries.

The Commission considers that a process for the reassessment of beneficiaries and re-allocation of costs of new investments is essential for having an effective beneficiaries-pays arrangement. The difficulties inherent in selecting an appropriate period for reassessment could possibly be overcome if the allocation of costs to beneficiaries also allocated property rights, which could subsequently be traded. However, until such arrangements are developed, an alternative could be an arbitrary period (say 10 years) specified for recalculating beneficiaries, balancing the need for stability against the need to identify changes in the market.

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[19] For example, an interconnector may be built between regions and although there may not be a significant price differential, customers may benefit from improved system security. However in the future where electricity flows may be predominantly in one direction, there will be a benefit to generators in the exporting region.

*Disputes*

NECA argues that the beneficiaries pay process will obviate the need for a contested process to establish the case for a new investment. The Commission considers that this would be the case in situations where beneficiaries could be accurately determined and were recalculated over time. However, the ambiguity regarding the proposed process for estimating beneficiaries may increase the level of disputes about the allocation of costs and potentially delay projects even where they have already satisfied the regulatory test.

One means of overcoming the problem of disputes delaying the commencement of a project may be to separate the commencement of the project from the beneficiaries pay process, as proposed in Powerlink's submission. Separation of the development of an investment from decisions as to who should pay for the investment would ensure projects with a net benefit would not be delayed by disputes over cost allocation.

However, the Commission notes that allowing a project to commence before determining the cost allocation to beneficiaries may foreclose non-network options. Conversely participants faced with the prospect of being identified as a beneficiary, and therefore a payee, may present a stronger case for non-network alternatives as part of the consultation under the beneficiaries pay process. The Commission notes that it may also lead to the risk of an unfunded project for the NSP for a protracted period. Therefore the Commission considers it preferable that such issues are resolved before project commencement. Further, the Commission considers that a more informed outcome from the regulatory test will be found if the beneficiaries pays process is completed first.

However, the Commission remains concerned that the proposed arrangements may lead to disputes and potentially delay new investments.

*Estimating customer benefits*

The proposed schedule 6.8 provides that once the proportion of benefits and costs accruing to generators, both collectively and individually, is estimated the residual benefits and costs of new investments are deemed to accrue to all customers of the relevant network. No provision is made in the proposed code changes for the estimation of benefits and recovery of costs from customer classes or individual customers.

While the identification of individual customers as beneficiaries of network investment would generally prove more problematic than the identification of benefits accruing to individual generators there may be instances where a large load or group of sites may be the major beneficiary of a new investment. The Commission considers that where individual or groups of customers can be identified as beneficiaries the same rationale for the recovery of costs of network investment from generators should apply to those customers. That is, where individual beneficiaries can be identified they should bear a proportion of the costs of network investment in proportion to the benefits derived.

*Recovery of costs*

The Commission considers that the proposed code changes are unclear about the costs that are payable by the beneficiaries, the timeframe over which costs are to be recovered, and whether or not the new network assets are included in the regulatory asset base. This could potentially result in confusion regarding issues such as rights over the assets.

The Commission considers that this ambiguity could lessen the public benefits of the proposed arrangements. The Commission therefore considers that these issues would need to be clarified before any beneficiaries pay process is implemented.

*Date of effect*

The Commission agrees with the concerns raised by the SA Treasury that the definition of new network assets as any asset on which work commences after 1 July 2000 creates ambiguity about which assets are subject to the beneficiaries pay process, depending how the term ‘work commences’ is interpreted. A broad interpretation could encompass projects on which preliminary feasibility and other studies have commenced thereby meaning projects on which construction does not commence until after 1 July 2000 may be classed as sunk costs. The SA Treasury has proposed that the definition of new investments be changed to ‘any transmission project for which the operational date is after 1 July 2000.’ The Commission considers that the proposal from SA Treasury provides a workable definition and supports that amendment to the proposed code arrangements.

*Threshold for inclusion in the beneficiaries pay process*

The Commission notes the concerns of Powerlink, the AEA and the NSW Treasury regarding the threshold for classification of new projects as large or small network assets. New network assets with estimated total capitalised expenditure in excess of $10 million are classified as large network assets and costs are recovered from individual generators and all customers in proportion to their estimated share of benefits. All other new network assets are classified as small network assets and costs are recovered from all generators and customers connected to the network without identification of individual beneficiaries.

The Commission notes the concerns of the AEA that for new small network assets the proposed arrangements do not maintain consistency with the principle of apportioning costs based on estimations of relative benefits wherever possible. Against this however, given the cost involved in identifying beneficiaries, applying this principle to small new network assets would imposed significant additional administrative costs proportional to the cost of the proposed project. Further, for smaller projects benefits to individual market participants may not be material and the task of identifying beneficiaries becomes more problematic.

The Commission notes Powerlink’s argument that the $10 million threshold is too low for the Queensland network because of the cost involved in the beneficiaries pay process, and because, in Queensland only projects with a cost in excess of $50 million will have material benefits to generators.

Setting the threshold for large and small network assets involves a trade off between assigning, to the extent possible, the cost of new network assets directly to those identified as beneficiaries without imposing significant additional administrative costs on the market. To this end the Commission notes the argument of the NSW Treasury that consideration be given to the appropriate threshold by reference to actual project experience of the network businesses and the substantial transaction costs that accrue when applying the consultation processes developed in respect of major investments.

While the Commission sees merit in setting the threshold by reference to actual project experience the lack of such information at the present time means decisions about the appropriate threshold would be arbitrary. Further deciding the appropriate threshold on a project by project basis would create ambiguity about whether a new investment will be classified as a large or small asset which would create uncertainty for market participants given the bearing of this decision on the method of cost recovery for the new asset.

Therefore the Commission considers that the proposed threshold of $10 million represents a sensible compromise between apportioning costs proportional to benefits received where practical without imposing unnecessary additional costs on the market. This proposal is also consistent with the code changes being assessed by the Commission in the Network and distributed resources package, submitted by NECA on 21 December 2000.[20]

*Network upgrades*

The Commission also notes the ambiguity in the proposed code changes about whether the definition of a new network asset (an asset of the NSP on which work commences after 1 July 2000) includes upgrading of the existing network. Further, the Commission notes the argument of SPI PowerNet that it is not clear whether the replacement or refurbishment of existing capacity qualifies as a large new network asset.

The Commission considers that these points require clarification before a beneficiaries pay process is implemented.

*Conclusion*

The Commission agrees with NECA's view that the current mismatch between those who benefit from new investment and those who pay for it leads to inefficient investment and inappropriate locational signals. The Commission considers that requiring all network users to contribute to the costs of new network investments where they derive a benefit from those investments can overcome this current deficiency.

However, the Commission considers that the proposed framework needs further work to ensure its implementation is effective. In particular the Commission is of the view that further work on the identification of beneficiaries at the commencement of new network investment, as well as through the life of the investment is necessary. Further effective mechanisms for dealing with questions about the accuracy of the estimates of beneficiaries and managing disputes regarding these estimates are also essential.

[20] National Electricity Code – Network and distributed resources, authorisation Nos: A90773 – A90775.

The Commission also notes several interested parties commented at the pre-determination conference and in subsequent submissions that a beneficiaries pays approach to new investment should be part of the transmission pricing arrangements.

The Commission considers that some further work must be undertaken by NECA regarding implementation arrangements and has imposed a review condition to address the development of the methodology for allocating the costs of new investments to all network users where they benefit from the investment (C6.2). The Commission considers that to be effective the methodology should include a default allocation of costs, to apply where the identification of beneficiaries is otherwise too difficult or subject to dispute. The Commission notes that development of a suitable default allocation may be difficult.

Further, the Commission requires NECA to investigate the possibility of developing tradeable property rights to be associated with the cost allocation. The implementation of the new beneficiaries pays arrangements can not proceed until NECA has completed its review of cost allocation methodology (C6.3).

The Commission notes that NECA has commenced the development of revised arrangements for new network investments, which seek to address the concerns above. The Commission supports this work and encourages NECA to consult further with market participants and governments to develop arrangements for new network investments that send efficient signals.

The Commission considers that in conducting this further work, NECA should have regard to the following features of a new investment regime, which are essential to achieve efficient investment and locational signals.

Firstly, there needs to be an ex ante regime for allocating the costs of new investment. In this way, network users are able to influence the assessment undertaken in the regulatory test between contributing towards the cost of a new network asset or investing in an alternative option such as network bypass, embedded generation or demand side management.

Secondly, a regime for allocating the costs of new investment should be recalculated regularly to ensure that over time, those who benefit from a new network investment pay for that investment. Without such a provision, new users may be able to free ride by using assets that for which they have not paid and some users may continue to be required to pay even though they no longer benefit. As a result there is the risk that this will lead to subsequent inefficient investment and locational decisions.

It is, however, difficult to design a regime for allocating the cost of new investments that is both ex ante and can be adjusted over time. Indeed, such a regime would require a system of property rights so that as parties left the network they sold their right to use the asset and their obligation to contribute to the cost of the asset to another network user. Likewise, new users wishing to utilise the asset would need to purchase a property right for the asset and contribute towards its cost.

### 6.2.6 Conditions of authorisation

**C6.2 The code must be amended to require NECA, within 12 months of this determination, to complete a review, in accordance with code consultation procedures, of Schedule 6.8 of the code. NECA's review must:**

**(a) identify an effective the methodology for allocating the costs of new investments;**

**(b) identify a default cost allocation to apply in circumstances where the outcomes of the cost allocation determined in accordance with the methodology are disputed; and**

**(c) examine the potential for property rights associated with the cost allocation to be introduced.**

**Within 3 months of the completion of the review NECA must make recommendations regarding code changes to be brought to the Commission for authorisation.**

**C6.3 The code must be amended so that the new beneficiaries pays arrangements can not be implemented until after the revised schedule 6.8 and any associated code changes arising from NECA's review have been inserted into the code.**

# 7. Service standards, negotiating framework and access services

The code distinguishes between 'prescribed' and 'excluded' network services. The revenue that an NSP receives for providing prescribed services is subject to a regulated cap. Excluded services are not taken into account within the revenue cap and their terms of provision are decided by bipartite negotiation, subject to any relevant code provisions. This chapter deals with proposed code changes relating to standards for prescribed services and the negotiation of prescribed and excluded services.

Code changes relating to generator and MNSP access services are also addressed in this chapter, including specific issues as to whether these should be prescribed services and/or negotiable services. Some broader issues relating to property rights and firm access were raised in submissions and these are also addressed in this chapter.

## 7.1 Prescribed service standards

The proposed code changes require all NSPs to publish the service standards to which they will adhere for the prescribed services to which their network prices relate. The service standards must include, and not be inconsistent with, any service standards imposed on the NSP by any regulatory regime administered by the relevant regulator.

### 7.1.1 Issues for the Commission

Appropriate service standards can provide a sound basis for ensuring that NSPs deliver cost-effective levels of service and do not abuse the market power arising from their monopoly position. Inappropriately low or high standards may result in public benefits being foregone through the under-provision or over-provision of network services respectively. Defining standard service levels may enable additional benefits to be realised by providing a reference point around which to negotiate customised levels of service.

### 7.1.2 What the interested parties say

*Setting service standards*

EnergyAustralia argues that the code changes provide the Commission with considerable discretion in setting service standards as part of its revenue determination. It also notes that there was a lack of clear agreement in the Specification and Negotiation of Network Services (SNNS) working group.

The NGF supports basic and well-defined service standards for NSPs, but does not believe that the code changes go far enough. It states that the standards proposed by the SNNS working group are insufficient in a competitive environment to capture the market impacts of network problems. It contends that a more market-based assessment of service standards is required, which accounts for the value that the market places on the transmission services at the time of the interruption. It cites the example of a network failure at 3 am for a domestic load being less costly than a failure at 7:30 am on a weekday morning.

Powercor and ElectraNet support the use of service standards as part of an incentive based regulatory regime and favour the introduction of uniform national service standards.

TransGrid raises concerns regarding the imposition of service standards as part of the revenue cap process. TransGrid is concerned that if the Commission were to impose such service standards on TNSPs, they would face a number of sources of potential liability in relation to failures. For example, TNSPs would be liable if they breach the service standards requirement under the code, the connection agreement or they fail to meet the service standards determined in the revenue cap setting process.

The 'one size fits all' approach is rejected by Powerlink who argues that the best approach involves tailoring service standards to each specific part of the network. It also believes that the proposed code changes are sufficient if they are applied in conjunction with the Commission's *Draft Regulatory Principles*.

Although ElectraNet contends that the relevant regulator should determine service standards as part of its regulatory review process, it also supports the proposal in the Commission *Draft Regulatory Principles*, that NSPs would propose, and the relevant regulator would determine, the specific and explicit service standards. It argues that this avoids a 'one size fits all' approach, as it allows for the recognition of different environments faced by the networks. ElectraNet also supports the establishment of agreed reliability service standards at network connection points, which it argues would provide clearer signals for regulated network investment.

Powercor raises concerns that the service standards that it will be required to meet and publish have not yet been determined and argues that it would be beneficial if a uniform set of service standards is introduced.

Several Vic DBs support a regime of competition using benchmarks and argue that this is consistent with the incentive-based approach to regulation. They argue that the establishment of any incentive based mechanism, benchmarks or minimum standards must be integrated into the NSPs' regulatory review process, as it is not possible to decouple price and performance.

The SA Treasury considers that the proposed code changes should place the appropriate obligations on NSPs to establish clear and measurable service standards. It suggests that TNSPs should propose service standards as part of the regulatory review process, with regulator monitoring of adherence to these standards. It also raises concerns regarding the enforcement powers of the regulator for non-compliance with the prescribed service standards and questions how the regulator will apply reductions in tariffs for non-compliance other than during a regulatory review.

The ACF argues that the regulators of monopoly distribution businesses should regulate both the setting of prices and access arrangements as well as quality of service standards. It believes that price setting cannot be undertaken independently of quality and service considerations.

### 7.1.3 What the applicant says

NECA argues that requiring NSPs to publish service standards at the same time that they publish prices declares to customers the standard of service they can expect to receive for the applicable standard price. NECA states that this will allow customers to consider, in an informed way, whether they need to negotiate for an alternative level of service and allows the relevant regulator to more clearly assess the value of the prescribed services offered to customers.

NECA's review concluded that service standards should be set for tariffed services provided by all networks from 1 July 2001 and that subsequently, the NSPs would propose service standards and the regulators would determine service standards as part of the regulatory review process. NECA's review also concluded that NSPs should publish consistent and compatible annual statistics on operational performance. It suggests that this should be based on a combination of those currently published by Great Britain's Office of Gas and Electricity Markets (OFGEM)[21], the Victorian Office of the Regulator-General (ORG), the NSW Independent Pricing and Regulatory Tribunal (IPART) and those suggested by the SNNS working group. It also considers that the regulators' forum should commission a benchmarking study, which includes a comparison of the relevant financial performance measures commencing with 2000/01 statistics.

### 7.1.4 Issues arising from the draft determination

In its draft determination the Commission imposed the following condition of authorisation:

**C7.1 Clause 6.2.4(a) must be amended to:**

> **Economic regulation is to be of the *CPI* minus X form or some incentive-based variant, and may consider service standards and any other elements that the ACCC considers appropriate, providing it is consistent with the objectives and principles outlined in clause 6.2.2 and 6.2.3.**

InterGen believes that the incentivisation of TNSPs within the current common network carriage model needs to be addressed and the Newcastle Group's methodology to incentivise TNSPs to provide/guarantee service levels should be considered by the Commission.

The Newcastle Group believes that conflicting requests from different network users, in relation to the timing of planned outages on the shared network, could be managed by ensuring that TNSPs had defined minimum service standards to all network users so that no user was disadvantaged by a TNSP acting in accordance with any given user's request.

Origin supports the Commission's requirements to amend the code so as to allow the Commission to take service levels into account when regulating transmission revenues.

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[21] Office of the Gas and Electricity Markets (OFGEM) is an amalgamation of the Office of Gas Regulation (OFFGAS) and the Office of Electricity Regulation (OFFER).

Powerlink believes the Commission already has sufficient powers to set TNSPs' targets for standards of service under its statement of regulatory principles. The proposed change under condition C7.1 gives the appearance of a policy change rather than the operational refinement of the code. Powerlink contends that policy changes should be initiated by jurisdictional input rather than by regulators or code administrators.

Tarong believes that market based measures such as the value of undelivered energy and the value of network constraints should be used by TNSPs to report the performance of their networks. Tarong states that publication of such measures would provide clearer indicators to network users and regulators alike as to the performance of TNSPs. As a history of such performance measures is established it may be possible to base some part of the regulated revenue on good performance, based on measures that demonstrate to network customers the value of the services provided by TNSPs.

TransGrid and VENCorp agree that service standards and the achievement of these standards, should be taken into account by the Commission when setting a TNSP's revenue cap. TransGrid submits that a TNSP's revenue cap should be reopened where new service standards create a material change to a TNSP's costs, but only in relation to the specific revenue impacts of the new service standard.

TransGrid submits that key aspects of each TNSP's service standard, including service area and associated service measure, should be included in the code. TransGrid states that the relevant service level should be proposed by individual TNSPs, based on their customers' needs, and approved by the Commission at each regulatory review.

VENCorp notes that its ability as a TNSP to deliver network services is determined by the terms and conditions of its agreements with the owners of the Victorian transmission system. VENCorp's accountability for network performance under the Commission's regulatory regime should be consistent with the terms of those agreements, which already include financial performance incentives.

### 7.1.5 Commission's considerations

It is necessary to set service standards and monitor service quality in order to protect network users from the abuse of market power by monopoly NSPs. Under a CPI-X revenue cap regulatory approach, a monopoly NSP may attempt to reduce operating and maintenance costs by more than the efficiency gains expected by the regulator in order to boost earnings. An effect of this may be to reduce the level of service provided to network users. Alternatively, monopoly NSPs may propose a higher quality of service than necessary, thereby requiring new investment, in an attempt to 'gold plate' its network. Quality of service monitoring by the relevant regulator, assisted by bonuses for performance or penalties for non-performance, can help ensure that NSPs maintain their quality of service.

Effective incentive-based regulation should include an explicit level of service, for which the NSP has been provided with sufficient regulated revenue to maintain the assets necessary to provide that level of service. Further, the regulatory compact should specify service standards that are reasonable and appropriate to each regulated NSP.

The Commission disagrees with TransGrid's comments that key aspects of each TNSP's service standards should be included in the code. The Commission considers it sufficient that the code changes require NSPs to publish service standards, including those imposed by the Commission. The Commission intends to further develop the service standards outlined in the *Draft Regulatory Principles* in consultation with all TNSPs and other interested parties.

The process will involve a review of existing transmission network service standards and the service standards outlined in Annex 8.1 of the *Draft Regulatory Principles*. The review will also report on transmission network service standards used internationally, highlighting the similarities and differences between the international service standards and those used in the NEM and review the appropriateness of a statistical based approach to setting service standards.

Several issues raised in submissions are best dealt with in the context of this review. For example, the NGF and Tarong submit that service standards should be market based, for example by taking into account the spot price, value of undelivered energy and levels of network congestion. While the Commission will examine this and other issues as part of its service standards review, it notes that it may not always be feasible to define market-based standards and that some recourse to more traditional, technical standards may be necessary.

The Commission will then develop a set of service standards and benchmarks suitable for regulatory purposes that will include performance indicators for interconnector availability and market-based outcomes to apply to each TNSP and individually. The Commission will also consider existing statutory obligations imposed by licensing authorities on TNSPs and incorporate these into the service standards developed. Where possible, the Commission will also consider the measures currently proposed by the joint jurisdictional regulators' Steering Committee on National Reporting Requirements (SCNRR).

In undertaking this review the Commission will consider how best to incorporate performance indicators on internal and external risks to the TNSP. The Commission will also consider how best to develop these measures into financial indicators.

For service standards to be effective, some mechanism is needed to ensure that they are adhered to. One approach is to publish performance statistics. The Commission believes that there are substantial public benefits from publishing service standards statistics, a practice that in Great Britain is undertaken by OFGEM. OFGEM requires transmission and distribution licensees to report annual statistics on system security, availability and quality of service. The statistics are intended to provide information on the continuity and quality of supply provided to end use customers.

For transmission networks, OFGEM uses the percentage of the time during which the system is not available for use, in addition to asking the transmission networks to provide a classification of the cause of the transmission system unavailability, for example system maintenance, construction, connection of users and faults. Whilst for distribution networks the number of interruptions and supply minutes lost is used as a measure of the security and availability of supply. OFGEM publishes the data in a form that allows customers to make a comparison between networks, to see which network is achieving a higher level of performance and, within the network, to see how the company compares with its ten-year average.

The Commission notes that while NECA's review concluded that NSPs should publish annual statistics on operational performance, it did not propose any code changes to this effect. The Commission has therefore imposed a condition (C7.1) allowing it to set, collect and publish annual performance statistics obtained from TNSPs that relate to the service standards published in clause 6.5.7(b).

The Commission agrees with Intergen's concerns and considers there may be substantial improvements in NSPs' service levels if they are exposed to financial incentives. In principle, network users might be given rights to compensation if affected by the failure of an NSP to provide prescribed services to the agreed standard. However, given the absence of a clear system of property rights and compensation arrangements the Commission considers there is a need to link NSPs' revenue caps to their performance in delivering prescribed services. As with OFGEM, the ORG and the South Australian Independent Industry Regulator publish regular statistics on the performance of DBs. The Queensland Competition Authority is in the process of establishing a service quality reporting and monitoring regime, requiring DNSPs to commence collection and storage of data of service quality measures.

The ORG has linked Victorian distribution businesses' service standards to their revenue cap in its *2001 Electricity Distribution Price Review Determination*. The ORG has achieved this by adding a service standards term 'S' to the (1+CPI)(1-X) factor in the price control. While the effectiveness of the ORG's methodology in imposing appropriate financial incentives on DNSPs has yet to be confirmed, the Commission considers that other jurisdictional regulators of distribution businesses should consider adopting similar incentive-based mechanisms. Accordingly the Commission has imposed a condition of authorisation (C7.2) to allow jurisdictional regulators to explicitly account for service standards when setting revenue caps for DNSPs.

Further, with regard to TNSPs, the Commission considers that the code must be amended to allow the introduction of an 'S' factor to adjust revenue caps where necessary to take account of TNSPs' performance in delivering prescribed services to agreed standards, (C7.3).

### 7.1.6 Conditions of authorisation

**C7.1 The code must be amended to allow the ACCC to set, collect and publish annual performance statistics obtained from TNSPs that relate to the service standards published in accordance with clause 6.5.7(b).**

**C7.2 The code must be amended to allow the jurisdictional regulators to use a form of CPI-X regulation that may take into account prescribed network service standards.**

**C7.3 The code must be amended to allow the ACCC to use a form of CPI-X regulation that may take into account prescribed transmission network service standards.**

## 7.2 Negotiating framework

The code currently permits negotiation between NSPs and network users on various issues. For example, a network user may negotiate to receive prescribed services at higher standards than normal; a generator may negotiate access compensation arrangements; or a network user may negotiate a discount on network service charges. However the code specifies little regarding the framework in which these negotiations should take place.

Clauses 6.5.9 and 6.14.7 of the proposed code changes require each TNSP and DNSP to establish a negotiating framework to be followed during negotiations for the provision of 'negotiable services': excluded services and higher than normal levels of prescribed services.

The code changes specify the matters to be included in the negotiating framework and require that each NSP's negotiating framework must be approved by and comply with any conditions imposed by the relevant regulator.

### 7.2.1 Issues for the Commission

In the absence of an appropriate negotiating framework, a monopoly NSP may be in a position to exercise undue market power, with resulting anti-competitive detriment.

### 7.2.2 What the interested parties say

The SA Treasury notes that there is a difference between the negotiations for higher service standards and the negotiations for price discounts (discussed in section 4.4 of this determination). It considers that if this difference can be reflected in a negotiation framework then it is appropriate to have a framework for both.

The SA Treasury submits that, when negotiations are about premium services, publishing the results may have the effect of establishing a market price for such services. It contends that full disclosure of the outcome of these negotiations may significantly reduce the ability of TNSPs to negotiate arrangements that use regulated assets or impose costs on other customers.

TransGrid considers that NECA's approach to negotiated services is confused and is based on a fundamental misunderstanding of the nature of 'negotiable services'. It contends that NECA is trying to place users of network services in a better position than they would be in a competitive market.

TransGrid notes that there is confusion in the definitions of negotiable services, prescribed services, excluded services and contestable services. A negotiable service is defined in the code as:

(a) an excluded service; or

(b) a prescribed service provided to a standard higher than that effectively required by the code or by the relevant regulatory regime, and does not include a contestable service.

An excluded service is defined as transmission or distribution services that are excluded from the revenue cap that applies to prescribed services.  The code also states that:

> Revenue caps set by the ACCC are to apply only to those services, the provision of which is the reasonable opinion of the ACCC are not expected to be offered on a contestable basis.

TransGrid states that these definitions imply that excluded services are contestable services.  It is therefore unclear what negotiable services relate to if it includes excluded services but excludes contestable services.

For example, TransGrid states that it is unclear whether negotiable services include generator access services, which involve the relevant NSP agreeing with a generator that it will compensate the generator if the agreed level of access is not provided.  This right of compensation is in effect a form of insurance for the generator against constraints that result in it being unable to receive the agreed level of access.  TransGrid argues that parties other than NSPs can provide this service, hence it is not a monopoly service and is in fact contestable.  TransGrid gives the example of entities unrelated to network businesses that provide these services in other countries.

If generator access services are considered to be negotiable services, then TransGrid argues that there is no need for separate provisions in clause 5.5 of the code.

TransGrid considers there isn't any need for the code to provide a negotiating framework culminating in a binding dispute resolution process in relation to negotiable services.

Several Vic DBs accept the need to ensure a level playing field in the negotiation of negotiable services to the extent that guidelines are established which detail commercially sensitive information that is considered to be 'off-limits'.  They argue that guidelines for negotiations should, where possible, focus the negotiations on performance outputs rather than inputs.  Such an approach allocates the incentives and risks associated with asset management to the NSPs rather than to customers.

Energy Australia states that the negotiating framework envisaged in clause 6.14.7 is not unreasonable, but further guidelines need to be developed in relation to an NSP's ability to obtain commercial information.

Ergon states that information asymmetry is a major impediment to a customer successfully negotiating an agreement with a monopolist. While it agrees that the list of information to be provided to the customer addresses this issue to a large degree, it argues that it may still be necessary for a procedure to be developed whereby the customer may exit the negotiation and seek mediation should the monopolist negotiate in bad faith.

The NGF argues that the proposed negotiation framework still lacks sufficient detail to be highly effective in giving TNSPs the incentive to negotiate on a fully commercial basis.  Further, they add that the proposed code changes are not strong enough to ensure the TNSPs do not possess an information advantage.

*Ability to propose service levels below standard levels*

The Commission's issues paper raises the question of whether NSPs should be able to propose service levels below the standards currently specified in schedule 5.1 of the code. Several interested parties agree that this should be permitted.

ElectraNet supports the proposal that networks should have the ability to propose lower service standards or more importantly that customers should be able to negotiate and accept lower service standards.

ElectraNet contends that the code does not specify an N-1 reliability standard for all situations, with the N-1 standard described only applying to the assessment of power system security. It notes that the code accepts the interruption of customer load, if necessary, to satisfy power system security requirements in addition to supporting the development of formal reliability service standards.

The EMRI and the NSW Treasury agree that NSPs should have the flexibility to set service standards lower than in the code, however, the EMRI suggests that this should be subject to customer acceptance.

### 7.2.3 What the applicant says

NECA argues that the creation of a category of negotiable services recognises the existence of a range of services that are neither standard nor prescribed, yet are services which cannot realistically be purchased competitively from alternative suppliers. It contends that the proposed amendments provide a process for negotiation of the price of such services on a more fair and informed basis. NECA argues that this will prevent the abuse of market power in the provision of such non-standard services and hence ensure more efficient outcomes.

NECA also states that there should be a defined process, including obligations that apply to both the NSPs and customers, for negotiating terms and conditions for the provision of contracted services. These negotiations should be based on a number of principles, which ensure equitable and efficient outcomes, including:

- networks responding within determined timeframe;
- access to information;
- publication of outcomes;
- assessing impacts on third parties; and
- treatment of the cost associated with processing the application.

NECA also contends that network customers should have access to any dispute resolution arrangements in the code as a means of resolving outstanding issues with the NSPs.

### 7.2.4 Issues arising from the draft determination

In its draft determination the Commission imposed the following conditions of authorisation:

**C7.2 Clauses 6.5.9(b)(3)(i) and 6.14.7(b)(3)(i) must be amended to require an NSP to notify a network user of the reasonable costs of providing the service.**

**C7.3 Clause 6.5.9(c)(1) and 6.5.9(c)(2) must be amended to give explicit powers to the Commission to approve and impose amendments on the negotiation framework between a TNSP and network users.**

**C7.4 A new clause must be inserted into the code that prevents an NSP from reducing service standards or increase costs to any other network users as a result of providing another user with negotiable services.**

**C7.5 The code must be amended to clarify the definition of negotiable services.**

**C7.6 The code's definition of a negotiable service must be amended to include prescribed services provided to a lower than standard level.**

**C7.7 The code must be amended to clarify that the proposed negotiation framework will also apply to the negotiation of all matters under clauses 5.5 and 5.5A.**

**C7.8 The code must be amended so that the negotiation frame work provisions apply to the negotiation of price discounts, with the exception that the requirement to publish the outcomes of the price discount negotiations should only relate to aggregate information.**

BPL welcomes the Commission's recommendations on service standards and widening the application of the intended negotiating framework. BPL considers that provided there is no material detriment to other participants, the code should permit the possibility that new entrants might establish connection arrangements prescribing lower as well as higher levels of service.

TransÉnergie considers that market participants should have the freedom to choose their required level of network service and that their network charges should be commensurate with their required level of network service.

TransGrid does not support the authorisation of the proposed code changes for the new negotiable services regime because the definitions of key terms in the regime cannot be practically applied.

TransGrid is concerned that while the Commission describes generator access and some other services as 'negotiable services', these services are actually 'contestable services'. TransGrid does not consider that the mere fact that a TNSP is the natural provider of a service because it may be better placed to manage the underlying physical risks related to it, means that the service is not contestable. Nor does it accept the Commission's conclusion that such an advantage means that other independent compensation providers will not be able to compete effectively with an NSP for the provision of generator access services without entering into backup arrangements with an NSP. TransGrid submits that generator access should be specifically excluded from the definition of 'negotiable services', as it should not be the subject of a regulatory regime requiring provision of those services.

TransGrid also submits that there are sufficient incentives for NSPs to enter into negotiations with potential users of the services without the need for a prescribed negotiating framework.

NECA states that the negotiation of provision of prescribed services to lower than prescribed standards could only occur in the rare circumstances of investment or re-investment in the relevant section of the transmission network, in order to access real cost savings for the TNSP. Further, it is unclear how negotiations for the provision of prescribed services to lower than prescribed standards would fit with the other obligations of TNSPs under the code.

### 7.2.5 Commission's considerations

The Commission supports the inclusion of a negotiating framework in the code for situations in which the network user has no practical alternative to purchasing services from the monopoly NSP. Although TransGrid argues that NSPs may face sufficient incentives to enter into negotiations with potential users of services without a negotiating framework, the Commission considers that the proposal will deliver public benefits, by alleviating the asymmetry in information and negotiating power that exists between network users and monopoly NSPs. The negotiating framework will also lessen the possible anti-competitive detriment that would arise if an NSP used its monopoly power to the detriment of a potential competitor. For example, the negotiating framework should place embedded generators, which essentially provide competition to network services, in a better negotiating position when seeking a network connection. The negotiating framework should therefore deliver outcomes that are more efficient and equitable.

While the negotiating framework is broadly acceptable, there are a number of areas that the Commission considers could be improved.

Clauses 6.5.9 and 6.14.7 require an NSP to identify the cost of providing a negotiable service, however, they do not explicitly state that an NSP will provide this information to the network user. The Commission requires that these clauses be amended to provide network users with all commercial information that may be required by the network user, including information about the cost of providing the service, (C7.4).

Clauses 6.5.9(c) and 6.14.7(c) of the code changes require NSPs to have their negotiating framework approved by the relevant regulator and also require that they comply with any amendments or conditions imposed by the relevant regulator. The Commission considers that without explicit criteria it will be difficult to assess a negotiating framework. The Commission has imposed conditions of authorisation (C7.5-C7.6) removing the requirement to seek ACCC approval and requiring that clause 6.5.9 to be amended to require each TNSP to:

- develop and publish a draft negotiating framework that conforms with the requirements of the frameworks specified in clauses 6.5.9(b);
- develop a final negotiating framework using the code consultation procedures; and
- following the conclusion of that consultation, publish the negotiating framework.

However, the jurisdictional regulators have indicated a preference for maintaining the approval process, and hence the Commission has not required an equivalent amendment to the provisions in the distribution pricing clauses. Due to the fact that MNSPs do not provide services that the negotiating framework applies, the Commission has made it a condition of authorisation (C7.7) that clauses 6.5.9(a) and 6.14.7(a) must be amended to specify that they do not apply to MNSPs.

The Commission is also concerned that there is no provision to protect other network users from reductions in service standards or increases in costs, should an NSP negotiate a higher or lower level of service for a particular customer. The Commission requires (C7.8) as part of the process for negotiating different levels of service, set out in clauses 6.5.9 and 6.14.7, the NSP must consider the potential impacts on other network users. Other network users that may be affected must be consulted and negotiated level of service variations must not infringe the current level of service and the rights other parties have under the code.

*Lower service standards*

The proposed code changes include higher than standard prescribed services but not lower than standard prescribed services. As noted in several submissions, it may be cost-effective in some circumstances to negotiate the provision of prescribed services at a lower than normal standard.

The Commission notes NECA's comments regarding TNSPs' other obligations under the code and its belief that the provision of prescribed services negotiated to a lower than standard level can only occur in rare circumstances. The Commission agrees that a TNSP can only negotiate lower service standards in certain circumstances.

For example, if there are three customers at one connection point that has spare capacity and N-1 security, it is not possible to give a customer a lower service standard and to charge them less, as they know they will actually end up receiving the same service level as they currently receive. This is because it is not possible to lower their service level without affecting other customers at the same connection point. In such situations the TNSP does not avoid any costs as a result of the customer's willingness to accept a reduced service level and it would be inappropriate for it to agree to a reduction in charges. However, there may be other situations in which there are real cost savings in offering a lower service standard, such as if there are three customers at a connection point, which is fully utilised and in need of upgrade to maintain existing service levels. In this case, one of the customers could negotiate a lower service level, so that it is disconnected when demand at the connection point exceeds the capability of the network. In this case, the customer should pay a lower charge that reflects the avoided cost of the augmentation.

The Commission therefore considers that the code must be amended to require NSPs to negotiate prescribed services to a lower standard than that specified in the code, where requested by a customer, (C7.9). However, it would be expected that such negotiations would only occur in exceptional circumstances and only where the interests and service standards of other parties have been preserved. Further, if a transmission customer agrees to accept a lower than prescribed level of service, the consequent reduction in customer TUOS usage charges may only reflect the TNSP's avoided costs (if any).

*Applicability of the negotiating framework*

The Commission sees benefit in requiring NSPs to develop a negotiating framework for services, such as generator and MNSP access, which are potentially contestable but for which there is not a well developed market and the NSP is the dominant and/or natural provider. TransGrid contends in its original and subsequent submissions that negotiable services are not necessarily monopoly services and that in such cases it would be inappropriate to impose a mandatory negotiating framework. TransGrid argues that, for example, other parties might compete with NSPs to offer generator and MNSP access services, citing the example of non-generators entering into energy hedges in competition with generators.

The Commission does not accept by this argument. Generators can be considered natural providers of energy hedges in the sense that their position in the physical energy market leaves them better placed than others to manage the risks involved. The Commission is not aware that other providers of energy hedges have been competitive on a sustained basis without entering into back-up risk management arrangements with generators. Similarly, the Commission anticipates NSPs would be the natural providers of compensation for network failures, being best placed to manage the underlying physical risks[22]. Independent compensation providers might not be able to compete effectively without entering into back-up arrangements with an NSP.

Thus it is not clear that there will be effective competition to provide access compensation services or other negotiable services. Moreover, even if effective competition does arise, the imposition of an even-handed negotiating framework should not have any detrimental impact. The Commission considers it would be imprudent to restrict the scope of applicability of the proposed framework.

Indeed the Commission is concerned that the scope may be narrower than intended, with undesirable consequences. It would seem appropriate for the framework to apply to negotiations conducted under the generator and MNSP access provisions in clauses 5.5 and 5.5A respectively. However it is not clear that these matters fall within the proposed definition of negotiable services. The Commission requires that the code changes be amended to clarify that the proposed negotiation frameworks will be applicable to all negotiations conducted in accordance with clauses 5.5 and 5.5A, (C7.10).

[22] The Commission acknowledges that NSPs are not necessarily well placed to offer compensation where one network user is constrained off by the activities of other network users. This is discussed further in section 7.3 and appendix C of this determination.

The Commission also considers that there are benefits in requiring the negotiating framework to be used for the negotiation of discounts on network general charges as allowed under clauses 6.5.8 and 6.14.6.

The Commission agrees with TransGrid's comments that there is confusion between the code's definitions of negotiable services, excluded services, prescribed services and contestable services. The Commission has made a condition of authorisation that the code must be amended to clarify the definition of negotiable services. A negotiable service must be defined as any matter negotiated under clauses 5.5, 5.5A, 6.5.8(c), (e) and (f), 6.14.6(c) and (e), negotiations for which must be conducted in accordance with the negotiating framework developed by an NSP according to clauses 6.5.9 or 6.14.7.

However, as discussed in section 4.4 of this determination, the Commission acknowledges that in some circumstances information on the outcome of individual TUOS discount negotiations may provide information about the network user's electricity costs to its competitors. The Commission has made it a condition of authorisation (C7.11) that the code must be amended so that the requirements to publish the outcomes of price discounts recovered from other users in accordance with clause 6.5.8(c) must take into account any commercially sensitive information.

As stated in section 4.4 of this determination, the NEDF expresses concern that these discounting arrangements would lead to information asymmetry in favour of customers. The Commission accepts that negotiations should be on a basis of full and symmetric information and therefore clauses 6.5.9 and 6.14.7 of the code must be amended to impose a similar requirement on the network user to disclose information as is imposed on NSPs in clauses 6.5.9(d) and 6.14.7(d). The changes to clause 6.5.9 must allow for such information to be passed on to the Commission for the purpose of 6.5.8(c).

### 7.2.6 Conditions of authorisation

**C7.4 Clauses 6.5.9 and 6.14.7 must be amended to require an NSP to provide all such commercial information, including but not limited to cost information, which a network user may reasonably require in order to engage in effective negotiation with the NSP.**

**C7.5 Clause 6.5.9 must be amended to require each TNSP, within 3 months of gazettal of the network pricing and MNSP code changes, to:**

**(a) develop and publish a draft negotiating framework that conforms with the requirements of the frameworks specified in clause 6.5.9(b);**

**(b) develop a final negotiating framework using the code consultation procedures; and**

**(c) at the conclusion of that consultation, publish the negotiating framework.**

**C7.6 Clause 6.5.9(c)(1) must be deleted and the words 'and subject to any amendments or conditions imposed by the ACCC' in clause 6.5.9(c)(2) must be deleted.**

**C7.7 Clauses 6.5.9(a) and 6.14.7(a) must be amended to specify that they do not apply to MNSPs.**

**C7.8 Clauses 6.5.9 and 6.14.7 must be amended to require network service providers to determine the potential impact on other network users of any negotiated variation in service levels to a network customer. The network service provider must notify and consult with other affected network users and must ensure that a negotiated variation in service level does not infringe the current level of service and the rights other parties have under the code.**

**C7.9 Clause 6.5.8 and 6.14.6 must be amended:**

**(a) to require network service providers to negotiate prescribed services or prescribed distribution services to a lower standard than that specified in the code, where requested by a customer; and**

**(b) to limit any cost reductions offered to the customer to those reflecting the network service providers' avoided costs (if any).**

**C7.10 The code must be amended to require negotiations between an NSP and a network user on the following matters to be conducted in accordance with the negotiating framework developed by the NSP according to clauses 6.5.9 or 6.14.7:**

**(a) any matter negotiable under clauses 5.5 or 5.5A;**

**(b) discounts to the customer TUOS general price or the customer common services price;**

**(c) negotiation of prescribed services or prescribed distribution services to a higher standard than that specified in the code; and**

**(d) negotiation of prescribed services or prescribed distribution services to a lower standard than that specified in the code.**

**Where the matter under negotiation relates to (b) above, the requirement in the negotiating framework to publish outcomes shall be limited to a requirement to publish aggregate information on the total costs of discounts negotiated and the portion of the costs to be recovered from other network users.**

**C7.11 Clauses 6.5.9 and 6.14.7 must be amended to impose similar obligations on the network user to disclose information as those imposed on the network service provider. There should be similar exclusions regarding confidentiality and restrictions on the passing on of information, except that the NSP must have a right to pass on information to the ACCC for the**

**purposes of satisfying the Commission it has complied with discounting guidelines as envisaged under condition 4.15.**

## 7.3 Generator and MNSP access services

The existing generator access arrangements, in clause 5.5 of the code, allow a generator to negotiate compensation agreements with any NSP who is required to process its connection enquiry or make it an offer to connect. The agreement can assign the generator the right to receive compensation when its network access is constrained. Conversely, the NSP can acquire a right to receive compensation if the generator's activities constrain other generators' access. The agreements envisaged in the code amount to property rights over network capacity and are sometimes loosely referred to as a form of 'intra-regional firm access' right.

It should be noted that the holder of an access right does not acquire any special privileges in terms of physical access, merely a right to financial compensation. Physical access to the regulated network is on an open access basis. Physical access for scheduled generation and loads is rationed on the basis of bid and offer prices, while other network users may be shed as a last resort measure. Participants may elect to pay for enhancements to the physical network, but receive no physical access guarantees in return.

On the basis of the proposed code changes, eligibility to negotiate access services would be extended to MNSPs and access services would be removed as one of the classes of transmission services that make up the network's aggregate annual revenue requirement (ie. clause 6.3.1(a)(5) of the code is deleted).

### 7.3.1 Issues for the Commission

Generator and MNSP access services represent a type of negotiable property right over the network. Properly constituted network property rights have the potential to enhance market efficiency through the elimination of free-riding and ensuring that externalities are properly accounted. On the other hand poorly constituted rights may decrease market efficiency by transferring risks and costs to parties not well placed to manage them, and may also be inequitable.

### 7.3.2 What the interested parties say

Powerlink argues that the code changes do not provide a sufficient framework for negotiation of firm access. Further, Powerlink argues that there is unlikely to be convergence in negotiations between TNSPs and generators on the issue of firm access because of:

- the possibility of nodal pricing and TCCs; and
- the widely held view that access hedges ought to be a third party insurance service.

Ergon supports the move of generator access from regulated to unregulated services. However, it expresses concern that it will be difficult for generators to negotiate a commercial arrangement with a TNSP because of the TNSP's monopoly power and information advantage. As a result, Ergon argues that generators may face unreasonable terms or conditions for access.

The SA Treasury believes that there is insufficient distinction between the unregulated generator access services and regulated generator negotiated use of system services. It states that the regulated negotiated use of system charges seems to relate to negotiated augmentations required to meet a generator's desired operating parameters, yet it is not clear how these and other regulated assets would be used to provide unregulated generator access services.

The IPA advocates the specification of property rights for new and existing transmission capacity. It argues that unless the level of access is defined in connection agreements, there is no basis for seeking a modified level of service. For example, there is no incentive on TNSPs to conduct maintenance at times when the value of access to generators is low.

The IPA states that the Victorian generators were sold with implicitly assured rights to the transmission system and that the cost of this firm access was reflected in the prices paid for the generation assets. It states that the transmission capacity serving generators in the Latrobe Valley was designed to allow all stations to operate at their maximum capacity for 99.8% of the time. The IPA states that these implied access rights should be made explicit and incumbent generators should have the option of purchasing more than their allocated firm capacity from TNSPs in the form of hedging contracts. New or augmented supply would either have to:

- accept a lower level of certainty (for example by compensating generators that it constrains off);
- arrange for a level of availability from an existing generator to be transferred to it; or
- augment the transmission line.

The IPA draws a distinction between the meshed transmission network, which has public good characteristics and radial lines, which it argues do not have public good characteristics because they benefit specific parties. It argues that the rights to and costs of radial lines should be allocated to those particular parties that benefit from them.

The IPA states that the alternative is to assume the TNSPs operate an open access transmission line and that no generator has preferential access. The IPA argues that this approach is sound when there is an abundance of capacity but that as the demand for capacity increases it leads to distortion. The IPA argues that this is likely to result in free riders and sub-optimal utilisation of and investment in the network. Further, if new generation is installed and there is no increase in transmission capacity, an open access regime increases the risk of incumbent generators being constrained off without compensation.

Transend states that the proposed code changes allow TNSPs to offer generators or MNSPs different types of network service. Firstly, they could offer financial firm access, whereby a TNSP would pay compensation (equivalent to the regional reference node spot price) to a generator or MNSP that is in the merit order dispatch but is constrained off the network. Transend argues that this type of service exposes TNSPs to market risk irrespective of the cause of the constraint. The second type of service that TNSPs could offer generators and MNSPs is an asset performance guarantee, under which a TNSP would only pay compensation (which would not be linked to the spot price) in the event of non-performance of the assets. Transend is concerned that both of these access arrangements expose TNSPs to risk because of market changes, such as the entry and exit of connectees, that are beyond their control yet affect their ability to meet performance requirements.

Transend believes that the code is unclear about the intention of clauses 5.5(f)(6) and 5.5A(g)(5). The clauses may be interpreted as providing incumbent generators and MNSPs with transmission property rights. If this is the case, then TNSPs would be able to enter into long term connection agreements with certainty. However, Transend argues if the intent of the clause is only that the new entrant must negotiate in good faith then a low cost new entrant has little incentive to enter into a connection agreement that requires it to compensate less efficient generation. In this case, clauses 5.5(f)(6) and 5.5A(g)(5) may act as a barrier to entry.

Transend argues that the code needs to be amended to clarify the intent of these clauses and the rights and obligations of TNSPs and new entrants under clause 5.5(e)(2) and 5.5A(f)(2) with respect to clause 5.3.5(d).

The NGF suggests that a transition to firm access would solve the problems generators have faced in negotiating generator access services. Firm access would provide market drivers on NSPs as they will select the cheapest option from either providing a specified level of service or paying compensation to participants. The NGF states that incumbent generators should not receive any special treatment and that if they want firm access, they should pay for it.

The NGF states that while the code allows generators to negotiate with an NSP for compensation if they are constrained-off, the generators are in a weak negotiating position because an NSP has the right to constrain the network without paying compensation. Further, the details of the negotiation process and the determination of the price of firm access (which is capped at LRMC) are unclear.

### 7.3.3 Issues arising from the draft determination

The Commission did not impose any conditions related to this issue in its draft determination.

Hazelwood believes that while the code provides for the generator and the TNSP to negotiate a level of access that provides for compensation in the event of constraint, the TNSP is unable to deliver this level of commitment. This is because the open access regime precludes allocation of capability, financial or physical, to specific generator parties.

Hazelwood states that the most practical mechanism given the current network arrangements would appear to be the establishment of a local nodal price, with the ability to allocate the available settlement surplus to the firmly-contracted party/parties.

Hazelwood considers that ‘firmer’ settlement residues provide a right only if they give the level of risk management sought by the participant, and only if they persist for times, according to participant requirement, approaching the life of the participant’s investment.

InterGen considers that firmer access rights will inevitably occur in the NEM. Ultimately this may equate to property rights in a contract transmission carriage model, however InterGen sees no immediate imperative, other than the firming up of settlement residues, to consider in the short term.

Loy Yang supports the NGF view that any further review of transmission and distribution pricing must address the issues of network property rights. Loy Yang believes that the inclusion of individually owned property rights and tradeability of those rights for generators will allow a move away from the centrally planned transmission system and will allow an improvement in market efficiency.

Enertrade, Loy Yang and the NGF consider that the principles in condition C4.1 of the draft determination should be extended to include the establishment of a property rights regime.

The NGF states that in return for the increased risk associated with a property rights regime, the networks must be allowed to retain some of the increased benefits in exchange for facilitating these benefits that undoubtedly will lead to greater levels of inter regional trade and the consequential increase in public benefits. The NGF contends that the Commission should also request NECA to explore and report back on opportunities for firming up existing settlement residues or equivalent.

The Newcastle Group suggests that firmer inter-regional access is a natural place to start applying firm access principles as certain risk-management tools are already in place and that firm SRAs are desirable. However, it acknowledges that some risks are outside the TNSPs’ control and that this issue involves more than one TNSP at a time, which raises coordination and accountability issues. The Newcastle Group is in favour of some form of firming up of a portion, or ‘firmness ranking’ of SRA products as a first step. This would require the Commission to reconsider TNSPs’ regulated revenue so as to properly reflect the risk they faced and reallocation of the SRA premium income to support higher value firmer products.

QLD Treasury submits that there is a need for a review of the operation and negotiation of firm access rights as part of the development of a revised network pricing arrangement. Any arrangement for firm access rights must recognise that the provision of and costs associated with firm access are additional to transmission costs that should be levied on generators. In addition, any regulatory structure must be flexible enough to reward NSPs for the financial risks associated with providing firm access rights. QLD Treasury notes that the current regulatory revenue cap process places incentives that do not facilitate or reward NSPs to negotiate firm access.

Stanwell believes that market based incentives should be used to compensate generators for constrained on or off generation during network outages, particularly planned outages. Stanwell considers that if generators are required to pay TUOS usage charges then they should be entitled to a minimum standard of service or able to claim firm access financial compensation for periods when constrained on or off.

Tarong advocates a system whereby any party may contract with a network owner for a negotiated level of access to the network and that participant secures an enforceable right to receive the services they are paying for, or compensation in lieu thereof.

Tarong agrees that network users should pay for an upgrade of network capability to relieve congestion, but argues that the users must receive a property right to the increased capability they have paid for.

### 7.3.4 Commission's considerations

*Removal of access arrangements from the revenue cap*

The proposed code changes will remove the risk premium associated with the provision of generator (and MNSP) access arrangements from the revenue cap. The costs associated with providing generator access are presently included in the revenue cap, so any residual costs that arise from the NSP paying out compensation in excess of the premium paid by the generator may end up being borne by other network users. This raises the possibility that an NSP and a generator (or MNSP) may negotiate an agreement that does not adequately take account of the impacts on other parties. As with other contestable services, the Commission as regulator, would need the TNSPs to demonstrate that any such negotiations on access arrangements do not facilitate a cost shifting arrangement between the regulated and un-regulated aspects of their business.

On the other hand, under the present spot market arrangements NSPs are not well placed to manage all the risks associated with access agreements because they do not receive congestion rents. Hence, they have a disincentive to enter into such agreements. Allowing NSPs to include the residual costs of providing access compensation arrangements in TUOS charges might reduce that artificial barrier. However, the Commission notes that this would be a second best solution that would merely pass the risks to others (transmission customers) who were not well placed to manage them either and who had no guarantee of receiving offsetting benefits. The Commission therefore supports the proposed change to remove generator and MNSP access services from the revenue cap. If necessary, further development of this arrangement can be addressed in the DRP.

*Extension to market network service providers*

In principle, the Commission supports the extension of the access compensation provisions to MNSPs. However, several submissions indicate the current arrangements appear unworkable. The Commission therefore recommends that NECA continue work on these arrangements to improve their implementation.

*Workability of the arrangements for access service*

The Commission expressed its concerns about the effectiveness of the 'firm access' arrangements in its original authorisation of the code in December 1997. In that determination, the Commission stated that it 'supports the NECA proposal of a full consideration of the issues surrounding firm access in the review of transmission and distribution pricing'.

The Commission shares the concern expressed in many submissions that the firm access provisions are ineffective and is disappointed that this issue has still not been resolved. However the Commission notes that NECA is making progress on this issue, as evidenced by its current consultation on code changes to improve the firmness of the settlement residue auctions. The Commission also notes that there are several ongoing reviews that may impact on how easy it will be to establish more effective provisions in the future.

NECA's Review of the Integration of Energy Markets and Network Services (RIEMNS) is examining the merits of more detailed regional pricing or even full nodal pricing. Either of these developments would have the potential to create a sounder basis for offering firm access. More detailed locational prices would provide a simple basis for setting access compensation, while the associated settlements residues would provide a means to underwrite the network usage risks which it is presently difficult for an issuing NSP to manage.

The next phase of NEMMCO's ancillary services review process is to look at network support services. Network constraints can be caused by failures of network support services. Improving the processes for managing network support services should thus contribute to a more secure basis for offering firm access.

The ongoing Market and System Operation Review is examining the demarcation between NSPs' and NEMMCO's accountabilities. Clarification of the areas of accountability may help provide a better basis for offering firm access, providing that the process results in risks and responsibilities being placed where they can be best managed.

The Commission believes that it will be important for the matter of network property rights to receive coordinated consideration in the various ongoing processes alluded to above. To add to the debate on this issue, a discussion of property rights is included in appendix C.

#### 7.3.5 Condition of authorisation

**C7.12 The code must be amended to require NECA, within 12 months of this determination, to review the scope for facilitating firm access to the transmission network through options such as introducing a regime of transmission property rights. The review must be undertaken using the code consultation procedures and be undertaken in conjunction with the reviews specified in conditions C4.2 and C6.2.**

# 8. Information disclosure

## 8.1 Unbundling TUOS usage and general charges

Under the current and proposed code arrangements TNSPs are required to publish transmission service prices. However, there is no requirement for TNSPs to separately publish components of these prices. Nor is there any requirement under the code for TNSPs to publish the methodology used in calculating these charges.

### 8.1.1 Issues for the Commission

The Commission is concerned that a lack of information disclosure related to network charges may lead to network users making inefficient decisions regarding network usage and where to locate their own investment, for example a large industrial site. A lack of information disclosure will exacerbate the information asymmetry that exists between network users and monopoly NSPs.

### 8.1.2 What the interested parties say

The AEA states that each TNSP should be required to disclose the methodology and assumptions used to determine prices at each connection point and that the Commission should be able to review the charges.

### 8.1.3 Issues arising from the draft determination

In its draft determination the Commission imposed the following conditions of authorisation:

**C8.1 The code must be amended to require that where TNSPs provide information to customers about transmission network charges, they must separately identify the TUOS usage and TUOS general components of charges levied.**

**C8.2 The code must be amended to allow transmission customers to request and receive information from TNSPs regarding their own TUOS usage charges and the methodology used to calculated them.**

BPL welcomes the Commission's recommendations and the AGO considers that unbundling of charges as per the conditions of authorisation C8.1 to C8.8 will enable consumers to make informed consumption decisions while also ensuring smaller customers have access to class-based information.

VENCorp states that condition 8.1 should be amended to clarify that TNSPs are required to provide this information to their customers (and not end consumers who are not connected directly to the transmission system). In regards to condition 8.2 and the role proposed for NEMMCO in calculating transmission charges, VENCorp questions whether this responsibility should rest with NEMMCO, rather than TNSPs.

Western Power states that it has no problem in providing its customers with information regarding their own usage charges and the methodology used to calculate them provided that condition C8.2 is revised to make sure that other customers' commercially sensitive information is not disclosed.

### 8.1.4 Commission's considerations

The Commission does not consider the current code arrangements for the publication of transmission service prices provide network users with adequate information to make efficient decisions about network bypass and usage. The code provides for network users to negotiate price discounts on various classes of transmission network charges, and where discounts on the TUOS general charge or common service charge are negotiated, for these discounts to be recovered from other network users (see section 4.5 of this determination).

The negotiation of price discounts on the TUOS general charge and common service charge provides a public benefit through encouraging use of the existing network and by encouraging users who might otherwise bypass the network to connect, thereby reducing charges to all network users. However, the unavailability of information about the structure of network charges may impinge on the ability of users to negotiate discounts, reducing the potential benefits of the discounting arrangements.

The Commission considers that in order to ensure this information is available to all network users these network charges should be separately identified. Therefore the Commission has imposed a condition of authorisation requiring TNSPs to give details of the split between the TUOS usage, general and common service charges in billing transmission customers.

Further, the Commission considers that transmission network customers have the right to information not only on the structure of network charges but also how these charges have been calculated.

By requiring TNSPs to provide users with their method for calculating the TUOS usage charges and the outcome of the modified CRNP analysis the rationale underlying all changes to charges should be demonstrable to network users.

The Commission has therefore imposed a condition of authorisation that TNSPs provide to transmission network users a copy of the methodology used to determine their TUOS usage charges on request, ensuring that it does not include confidential information provided to the TNSP by another person.

The Commission considers providing these sets of information to network users will promote more efficient network usage and bypass decisions. This will result in more efficient network utilisation and increase the effectiveness of bypass as a competitive pressure faced by NSPs. Providing users with information about the structure of network charges will also lead to a greater transparency in these charges. The Commission considers the benefits to the market of providing this information far outweighs any cost associated with providing the information.

### 8.1.5 Conditions of authorisation

**C8.1 The code must be amended to require that where TNSPs provide information to transmission customers about transmission network charges, they must separately identify the TUOS usage, TUOS general and common service charge components of charges levied.**

**C8.2 The code must be amended to:**

**(a) allow transmission customers to request and receive information from TNSPs regarding their own TUOS usage charges and the methodology used to calculated them; and**

**(b) specify that in fulfilling a request for information by a network customer, TNSPs are not required to provide commercially sensitive information of a third party.**

## 8.2 Unbundling TUOS and DUOS charges

Under the current code arrangements distribution charges bundle together the cost of both the transmission and distribution networks. The proposed code changes allow large distribution customers to request unbundled network charge information from the DNSP. The proposed changes also provide for the end-use customer to meet the reasonable direct costs of providing the unbundled data. Further, for all other end-use customers, DNSPs must publish unbundled network charges information on a customer class basis.

### 8.2.1 Issues for the Commission

Providing information on both TUOS and DUOS network charges will better inform customers negotiating with NSPs and considering network bypass options. Better informed decision making about network bypass and usage, will lead to more efficient network utilisation overall and increase the effectiveness of bypass as a competitive pressure faced by NSPs. The overall benefits of such information provisions must be balanced against the costs incurred in the estimation and dissemination of unbundled network charges.

The benefits of providing such information will also be dissipated where the relevant provisions are subject to derogations, and do not come into effect for some time.

### 8.2.2 What the interested parties say

The AEA argues that a 30 day period is too long for customers to wait for a TUOS/ DUOS disclosure statement and that 14 days is more appropriate (once systems that calculate the statements have been developed). The AEA also argues that:

- clause 6.14.8(e) needs to be amended so that the DNSP is required to disclose the basis and methodology used to allocate TUOS to customer classes;

- clause 6.14.8(b) needs to be amended so that only the reasonable incremental costs incurred in preparing the statement should be passed on to the customer;
- clause 6.14.8 needs to be amended so that the costs of preparing the statement are clearly identified in advance; and
- the unbundling provisions should be included in chapter 5, because chapter 6 has been derogated away from.

Several Vic DBs indicate support for the principle of cost reflective charging where practicable, especially where this encourages price responses that increase the economic efficiency of providing the service. However, while Several Vic DBs see some benefits in unbundling, they also believe that the costs are likely to far outweigh the benefits, and hence, do not support the unbundling of TUOS and DUOS charges.

The AGO supports full unbundling of network charges to all levels of customers. The AGO asserts that this will provide customers with the information they need to make informed decisions on economic and environmental impacts arising from any action they undertake. It believes that this should be phased in on a progressive basis.

The ACF states in its submission that transmission and distribution charges should be unbundled.

The NSW Treasury believes that the code changes are appropriately placed in the correct segment of the code. It goes on to say that the transitional nature of the derogations is well understood both within the industry and the market place. Furthermore, scope exists in the current regulatory framework for jurisdictional regulators to deal with the issue of unbundling and the NSW Treasury does not support ad-hoc changes to the integrity of the current regulatory framework.

TransGrid supports the basic thrust of NECA's proposal because it believes it is appropriate to ensure that network users who are sensitive to transmission charges are able to determine the transmission costs that they bear. It notes, however, that moving beyond the recommendations would involve DNSPs incurring significant implementation costs associated with providing information.

EnergyAustralia states that no cogent case has been presented to quantify the potential benefits or demonstrate that unbundling network charges would deliver a net public benefit. It says that it is only a requirement because the existing network pricing structure exacerbates the demand for such an unbundled service.

### 8.2.3 What the applicant says

NECA outlines a number of benefits for network users associated with unbundling network charges including:

- the creation of a more equal negotiation setting with NSPs;
- more informed input into the regulator's tariff setting; and
- more informed decisions on network bypass.

NECA states that the small group of customers that can make specific use of unbundled information are likely to be eligible for a TUOS/DUOS disclosure request under conditions specified in clause 6.14.8. For smaller customers such specific information is likely to be less useful and more expensive to provide. NECA believes that for smaller customers it is more feasible for the DNSP to provide an annual statement setting out the percentage of TUOS and DUOS charges recovered from each class of customer.

### 8.2.4 Issues arising from the draft determination

In its draft determination the Commission imposed the following conditions of authorisation:

**C8.3 Clause 6.14.8 must be inserted into part of the code that is not currently subject to a jurisdictional derogation.**

**C8.4 Clause 6.14.8(b) must be amended by replacing '30 days' with '10 working days'.**

**C8.5 Clause 6.14.8(b) must be amended to specify that:**

**a) the charge for providing the TUOS/DUOS disclosure statement must be no greater than the variable costs incurred by the DNSP in preparing the statement; and**

**b) the fixed costs are to be incorporated in the regulated revenue requirement of the DNSP.**

**C8.6 Clause 6.14.8 must be amended to require the DNSPs to provide customers with a detailed information on how the network charges and allocations were determined. This information must be sufficient to allow customers to assess the impact on their network charge resulting from a change in their network use.**

**C8.7 The code must be amended to require DNSPs to provide customers with details of the TUOS usage and general charge components of their network charges, where requested.**

**C8.8 Chapter 6 of the code must be amended to require DNSPs where practical, to preserve the economic signals of TUOS charges when passing these charges onto customers.**

The AEA is keen to see a progression to the full unbundling of transmission and distribution pricing for each customer and that this should be done by retailers rather than distributors.

Ergon considers that condition C8.7 regarding the separation of TUOS usage and general charge components is not currently calculated, but on request by a customer of the >10 MW or 40 GWh classification, this information could be provided for a relevant fee. However for cost pool customers, this would only be available on a c/kWh postage-stamped basis. Provision of information on other than this basis would not be possible from the DNSP's perspective.

Ergon support the intent of Condition C8.8. However, for the general cost pool customers (<10MW or 40 GWh), whilst a degree of economic signalling of TUOS charges can be preserved by allocating TUOS by transmission node, the charges are postage-stamped on a c/kWh basis.

QLD Treasury does not support the unbundling of TUOS and DUOS for franchise tariffs in Queensland. For smaller customers to whom contestability is not yet an option, the disaggregation of these tariffs at this point will increase costs, does not provide any net benefits and will ultimately lead to increased tariffs prices. Only if and when a form of congestion based network pricing is introduced will the disaggregated information prove to be of financial benefit to smaller consumers.

QLD Treasury notes that its position not to disaggregate DUOS and TUOS information will not impact on the provision of this information to those large franchise customers (>200MW pa) who are able to choose contestable terms. This is because DUOS and TUOS charges are already published in Queensland for these customers and this arrangement allows these customers to examine the financial merits of contestable prices against franchise prices and, therefore, achieves the same outcome that the Commission is seeking.

On this basis, QLD Treasury recommends that the Commission only extend the policy of disaggregating DUOS and TUOS prices to customers who are contestable or eligible to take contestable terms.

NECA states that information on the calculation of network charges and allocation can only be provided in a sufficient level of detail to enable a distribution customer to assess the impact of a change in network use on its network charges where the distribution customer has a load of the size, or has the metering equipment, referred to in clause 6.14.8(a) of the code.

### 8.2.5 Commission's considerations

For the development of transparent network prices the Commission considers it is critical that some form of unbundling takes place. When customers can observe the separated costs associated with their use of the distribution and transmission network, and understand how these costs will change after a change in network use, investment decisions will be made aimed at increasing the efficient utilisation of the network. Such investments may include demand side management, co-generation and network bypass.

The Commission also agrees with NECA that unbundled information will place network customers in a better position when negotiating with NSPs.

With respect to the extent to which specific unbundled information will be available to customers, the Commission supports NECA's view that it is feasible and practical to limit this information to the identified customers. Unbundled information on class basis for smaller customers would provide the appropriate level of information considering their limited ability to reduce such costs and the high costs of providing specific unbundled information to every customer.

The Commission considers it is important that customers not only receive unbundled cost information, but that they also understand how this is derived. Therefore the Commission believes that DNSPs must not only provide unbundled information but also detail how such information was determined. This should be required for specific disclosure statements as well as the information provided on a customer class basis. NECA recognised the need for such information stating in their final report, p.57, that:

> Customers should be given sufficient information by their DNSPs to allow them to understand the information provided by the unbundled charges, including the ability to check the impact of their proposed network use changes with their NSPs.[23]

The Commission considers that DNSP must provide details of the procedures for determining the unbundled charges, both for specific customers and customer classes, to enable customers to determine how the network charge is related to network use. On the condition that the DNSP ensures the pricing methodology can be easily understood by customers, additional information would not be required to be supplied by the DNSP.

The Commission considers that, consistent with the requirement for TNSPs to provide details of the split between TUOS usage, TUOS general charges and TUOS common service charges, DNSPs must also, on request, provide customers with details of the TUOS usage, general and common service components of distribution charges.

The Commission notes Ergon's, QLD Treasury's and NECA's concerns and acknowledges metering technologies will limit the DNSPs ability to do this. Therefore, the Commission considers that the provision of this information on an individual basis must be limited to customers which have metering equipment which is capable of capturing relevant transmission and distribution system usage data.

In section 5 of this determination, the Commission imposed a condition of authorisation requiring DNSPs to allocate TUOS prices to some distribution customers[24] in a way that preserves the economic signalling of the TUOS prices.

Under the proposed code changes, the DNSP has the ability to set charges for disclosure statements that are no greater than the reasonable expenses directly incurred in preparing the statement. The Commission considers the DNSP may use this arrangement to limit the number of disclosure statements it has to provide. This could be done by allocating the establishment costs (information systems and staff training), directly incurred as a result of receiving the first information disclosure request, to the first applicant. The resulting high charge may deter the customer from going ahead with the request. The next customer would experience the same problem.

To prevent this from occurring, the Commission considers that the fixed costs (the costs associated with establishing systems and procedures to handle disclosure requests), should be included in the DNSP regulated revenue cap to be recovered on a customer wide basis. The distribution customers requesting a TUOS/DUOS disclosure statement should only pay the variable costs associated with its provision. The Commission has

[23] NECA, Transmission and Distribution Pricing Review – Final Report, July 1999.

[24] Customers which have metering equipment which is capable of capturing relevant transmission and distribution system usage data.

imposed a condition of authorisation (C8.4) limiting the reasonable expenses taken into account when setting disclosure statement charges to the variable costs of providing such a statement. The Commission notes that in some jurisdiction the DNSPs are already providing this service without explicitly charging their customers, and notes that the jurisdictional regulators will need to ensure that DNSPs do not take advantage of the new code provisions to effectively charge their customers twice.

Whilst the Commission agrees that it would be an onerous and expensive task for the DNSPs and all retailers to redevelop IT systems to deliver disaggregated customer bills, this is not what the code change requires. Rather, DNSPs are required to produce a statement with separate network charges upon request and publish an annual statement of separate network charges for each customer class.

The Commission considers the DNSP should be able to provide this unbundled information from their existing systems, perhaps with minor modifications. The Commission believes that a 30 day period is an excessive amount of time to provide a customer an estimate of the charge for providing unbundled information. A period of 10 working days would seem sufficient time for a DNSP to provide an estimate of the appropriate charge.

The Commission considers the 30 day period the DNSP has to produce the TUOS/DUOS disclosure statement after the customer has confirmed the request is appropriate, given the added responsibility of demonstrating understandably how the charges were derived.

Since DNSPs have the ability to provide some degree of unbundled information at present, the Commission believes that clause 6.14.8 should come into effect at the time the Commission's authorisation of the network pricing and MNSP code changes takes effect. Clause 6.14.8(a) needs to be amended to reflect this.

Further, given the proposed code changes impact on the transparency of prices and not the level of current charges, the Commission sees no reason for a long transition path to the unbundling arrangements. Therefore the Commission requires the code to be amended such that the TUOS/DUOS unbundling provisions are not subject to jurisdictional derogations, by default.

### 8.2.6 Conditions of authorisation

**C8.3 The code must be amended to require DNSPs to provide customers, with a load of greater than 10MW or 40GWh per annum or which have metering equipment which is capable of capturing relevant transmission and distribution system usage data, with details of the TUOS usage, general and common service charge components of their network charges, where requested. The code must be amended to require DNSPs to notify customers of the charge for providing this information.**

**The amendments must be on the same basis as specified in clause 6.14.8 and amended by C8.3-8.6.**

**C8.4 Clause 6.14.8(b) must be amended to specify that the charge for providing the TUOS/DUOS disclosure statement must be no greater than the variable costs incurred by the DNSP in preparing the statement.**

**C8.5 Clause 6.14.8(b) must be amended by replacing '30 days' with '10 business days'.**

**C8.6 Clause 6.14.8 must be amended to require the DNSPs to provide customers with detailed information on how the network charges and allocations were determined, upon request. This information must be sufficient to allow customers to assess the impact on their network charge resulting from a change in their network use.**

**C8.7 Clause 6.14.8 must be amended so that it takes effect immediately upon gazettal of the network pricing and MNSP code changes.**

# 9. Embedded generation

The proposed code changes state that where a generator connects to a distribution network, and this reduces the TUOS usage charges levied on the DNSP, the full reduction in those charges must be passed through to the embedded generator. The code changes also propose that the provision of standby services to embedded generators would be treated as a contracted service, where the terms and conditions of supply are to be negotiated.

## 9.1 Issues for the Commission

The issue for the Commission is whether the proposed arrangements deliver public benefits through recognition of the benefits that embedded generators may provide. The Commission also wants to ensure that the proposed arrangements do not overcompensate embedded generators, thereby giving them an advantage relative to other generators.

## 9.2 What the interested parties say

Ergon, Stanwell, the ACF, the AGO and TransGrid support the pass though of TUOS savings to embedded generators. However, Ergon qualifies its comments by stating that the pass through of TUOS savings should only apply to bona fide network, customer related or renewable energy projects, not to larger projects that might locate in the distribution network to obtain that benefit. Stanwell states that embedded generators should receive the full TUOS pass through since they potentially benefit all network users through enhancements in network reliability, system security and a reduction in capacity constraints. Along with supporting the full TUOS pass through, the ACF argues that where a new embedded generator pays deep connection costs then it should receive preferential access compared to future users of these assets. TransGrid supports the proposed code changes on the understanding that TUOS pass through implies that only avoided marginal transmission costs are passed onto embedded generators.

Powerlink and VENCorp argue that passing through the savings in TUOS usage charges to embedded generators may create perverse incentives for generators to locate within distribution networks. Powerlink outlines four issues that may enable embedded generators to game the definition of the distribution network:

1. the definition of the boundary between transmission and distribution is arbitrary;
2. certain parts of some distribution networks are essentially ‘transmission in nature’ (sub-transmission), and can support a large connected generator;
3. there is no size limit on the definition of an embedded generator; and
4. network assets that are currently defined as transmission can readily be converted to distribution assets.

VENCorp adds to these points, arguing that the pass through of TUOS savings should apply to any generator connected to distribution voltages, rather than just a distribution network, as the benefits to the shared transmission network will be similar. VENCorp also expresses concern that a generator located at the same terminal station, but at extra high voltages, receives no TUOS savings although its impact on the transmission network is the same as an embedded generator.

The AEA gives three reasons why the proposed code changes with respect to embedded generation are unacceptable. Firstly, the AEA argues that the DNSP should pass through the full savings it makes when an embedded generator connects to its distribution network. This would include common service charges and the TUOS general charge, which are currently excluded from the allowable TUOS pass through. The AEA argues that transmission common service costs are avoidable rather than sunk costs and will therefore decrease if generators embed within a distribution network rather than connect to a transmission network. The AEA considers that generators should be recompensed for this benefit.

Secondly, the AEA argues that embedded generators should not pay for deep transmission augmentation unless they request improvements to the normal access arrangements.

Thirdly, the AEA argues that TNSPs have too much flexibility in determining the level of the rebate to embedded generators. This arises because the rebate is based on the TUOS usage charge, which the TNSP selects from a range determined using three methods. TNSPs can use this power to discriminate against embedded generators by limiting the size of TUOS pass through. For example, if the LRMC of transmission use is high, TNSPs may choose to calculate the TUOS usage charge using the CRNP methodology in order to avoid a large payment to the embedded generator. However, in the case where the LRMC is lower than the CRNP, the TNSP may choose to use the LRMC methodology to determine the TUOS pass through. The BCA ERTF agrees this last point, stating that the proposed code changes are anti-competitive and are inconsistent with the objectives of the code. It argues that there needs to be greater disclosure and transparency in the determination of the TUOS usage charge that is used to determine the payment to embedded generators.

EnergyAustralia, the NSW Treasury and the SA Treasury oppose the proposed TUOS pass through policy on the grounds that it over compensates embedded generators for their locational decision and thus provides them with a competitive advantage over transmission connected generators. In its objection to the code changes the NGF states that embedded generators should only be compensated for the real cost savings they deliver to the transmission network.

SPI PowerNet also objects to the proposed TUOS pass through policy. Firstly, SPI PowerNet states that if the current TUOS charges are not cost reflective then the pass through of avoided TUOS will not provide the correct locational signals to embedded generators. Secondly, under a nodal pricing framework the full transmission cost savings created by an embedded generator will be reflected in the reduced energy payments by the loads served by the embedded generator. In this system there is no further need for locational signals, such as the pass through of avoided TUOS. In a nodal pricing framework the TUOS charges reflect the recovery of sunk costs, which are not avoided by the construction of the embedded generator.

The EMRI states that the proposed TUOS pass through policy does not ensure competitive neutrality between embedded and transmission connected generators. The EMRI argues that existing generators should pay for the sunk costs of the network on a beneficiaries pay approach as proposed for new investments.

## 9.3 What the applicant says

NECA argues that the proposed code changes will ensure that embedded generators are appropriately rewarded for connecting to the distribution network, since the TUOS usage charge that is passed through will reflect the avoided LRMC of transmission augmentation. Embedded generators will also receive a signal to locate where they provide maximum benefit to the transmission network by relieving congestion. For example, in locations where the transmission network is congested, the LRMC of augmenting the transmission network will be high. Generators locating in a nearby distribution network will therefore reduce the load on the transmission network and defer the need for augmentation. Embedded generators will receive a high payment for the TUOS usage charge savings to the DNSP, thereby signalling the benefits of locating in the distribution network. Conversely, in locations where the transmission network is under utilised, the TUOS pass through will be small, if not zero, thereby signalling the minimal benefit that embedded generators will add to the transmission system.

## 9.4 Issues arising from the draft determination

In its draft determination the Commission imposed the following conditions of authorisation:

**C9.1 The proposed clause 5.5(i) must be replaced with words substantially equivalent to the following:**

**To calculate the amount to be passed through to an *Embedded Generator* in accordance with clause 5.5(h), a *Distribution Network Service Provider* must if *transmission usage prices* were in force at the relevant *transmission connection points* throughout the relevant *financial year*:**

1. **determine the transmission usage charges that would have been payable by the *Distribution Network Service Provider* for the relevant *financial year* if the *Embedded Generator* had not injected any energy at its *connection point* during that year;**

2. **determine the amount by which the charges calculated in (1) exceed the transmission usage charges actually payable by the *Distribution Network Service Provider*, which amount will be the relevant amount for the purposes of clause 5.5(h);**

**else the *Distribution Network Service Provider* must apply an equivalent procedure to that component of its transmission charges which is deemed by the relevant *Transmission Network service Provider* to represent the**

**marginal cost of transmission, less an allowance for locational signals present in the spot market.**

The AEA reiterates its belief that embedded generation should attract a rebate of all avoided TUOS, not just the usage charges, based on the following arguments:

- a party that provides an equivalent service to transmission should be able to recover an equivalent total revenue;
- denial of a full rebate on avoided TUOS will result in long term loss of dynamic efficiency as it reduces the competitive position of distributed generation technologies; and
- generators and customers will be motivated to bypass the network so as to fully avoid network costs, unnecessarily stranding distribution networks.

The AEA requests that the Commission also consider broader public costs and benefits such as the environmental benefits of embedded generation, its assistance with local system reliability and security, and impacts on costs payable under the Mandated Renewable Energy Act.

The AGO supports the proposal for embedded generation to receive a full rebate of TUOS usage charges and contends that any over recovery of the general charge by the DNSP should also be passed to the embedded generator. Origin also considers that embedded generators should receive a full rebate and is concerned that the present proposals will result in windfall gains to distributors. Any perverse incentive for large generators to connect at distribution levels would not be material because of other offsetting factors such as unfavourable loss factors and increased risk of being constrained off.

ENERGEX contends that direct allocation of some TUOS costs to transmission-connected generators would provide more efficient and transparent signals than a complex and costly system of rebates. It endorsed the NEDF proposal that the existing transmission-connected generators should pay for that component of the transmission network which was constructed to convey their output to load centres. The NEDF considers that its proposal would correct the present incentive for an embedded generator to bypass both distribution and transmission networks.

Ergon supports moves towards clear requirements as opposed to negotiated arrangements, but requests early resolution of outstanding ambiguities, such as the sharing of benefits when more than one generator is embedded in the same part of a distribution network.

The Newcastle Group questions whether an embedded generator actually obviates the need for network augmentation. As a substitute for transmission augmentation, embedded generators have a reputation for lower reliability. Therefore it may not be appropriate to award avoided TUOS to embedded generators. Further, the issue can become circular in that an augmentation will only be avoided where it is the most net beneficial option. If this is the case it should go ahead and the avoidance of it should not subsidise an investment that is less net beneficial (ie the embedded generator). If the augmentation is not the most net beneficial option then it would not pass the regulatory test and hence would not be avoided by the location of the embedded generator.

QLD Treasury considers that rebates should be capped at the actual cost savings of the rebating organisation, and should be conditional on the generator paying the full costs of connection, including any network upgrade costs. It recommends a cap of 30 MW on the size of eligible generators so as to eliminate any perverse incentive on large generators to connect at distribution levels and minimise the financial consequences for other customers of the TNSP. It also considers that rebates should be subject to the generator entering into availability commitments and performance requirements so as to ensure reliability of supply (for which NSPs are held responsible under the Code) is not compromised. It also states that, when compared to transmission connected generators, embedded generators receive a reward for lowering loss factors within the region that it is connected.

Tarong notes that some of the benefits of an embedded generator are reflected in more favourable loss factors for surrounding customers. To the extent that the avoided TUOS charges reflect the cost of network losses, they should not be rebated to the generator as this would be providing the same benefit twice, once to the embedded generator and once to the end-use customers. Instead there needs to be the possibility for the generator to capture some of the loss-factor benefits accruing to customers. Tarong considers that the generator could achieve this by contracting with customers at a price that was within the range determined by its pre- and post-commissioning loss factors. Thus it should be possible for the arrangements for embedded generators to encourage those generators to locate for the energy market price advantages rather than to receive rebates.

### 9.5 Commission's considerations

The public benefits of the code's network pricing arrangements will be enhanced if embedded generators receive signals to locate and operate their facilities in ways that contribute to an efficient market.

The code changes propose that an embedded generator is entitled to receive an automatic pass through of the avoided TUOS usage charges from the DNSP to which it is connected.

The Commission agrees with the NEDF's and ENERGEX's view that requiring generators to contribute to the costs of the transmission network would provide a more efficient and transparent mechanism than the TUOS rebate option. Indeed, the Commission considers that revised arrangements for new transmission augmentations should improve locational signals for generators within the transmission system.

However, until such arrangements are implemented, the Commission considers it appropriate that embedded generators be entitled to a rebate of the TUOS usage charge as it signals the benefits to the transmission network of locating some injection points within distribution networks. The benefits that arise will include relieving congestion, deferring network augmentation or saving DNSPs a portion of their contribution to TUOS usage charges. The Commission also considers that the automatic pass through of the TUOS usage charge simplifies the NEM's network pricing arrangements because embedded generators no longer need to negotiate with monopoly DNSPs for compensation where they have provided a benefit to the network.

The Commission agrees with NECA's claim that paying embedded generators a rebate based on the forward looking costs of network use will provide them with the appropriate locational signals and will compensate them for the benefits they provide to the transmission network and market. If the usage charge rebate reflects the future costs of capacity expansion at a particular connection point, embedded generators will have an incentive to locate in regions where they provide a relatively high degree of network benefits, for example, by relieving network congestion and deferring augmentation. In regions where there is little congestion at present or in the near future, the usage charge should be low, signalling to embedded generators the small benefits provided to the network from connecting at the distribution level.

However, the proposed rebates will only achieve their objective if TUOS usage charges are calculated efficiently so as to reflect forward looking costs. As discussed in section 4.2 of this determination, the Commission considers that there are several inadequacies with the code change proposals regarding the TUOS usage charges, for example the fact that they are based on the costs of the existing network. Nevertheless, the Commission considers the proposals represent an improvement over the current code arrangements in that embedded generators will at least automatically see a pass through of the usage charge savings obtained by the DNSP.

The Commission agrees with interested parties' comments that allowing TNSPs the discretion to choose an embedded generator's TUOS usage rebate from within a range could disadvantage an embedded generator. Indeed, this is one of the reasons why the Commission has imposed a condition that the proposal for the three methods of calculating TUOS usage charges must be replaced with a default methodology (see section 4.2 of this determination).

Several interested parties criticise the pass through of avoided TUOS usage charges on the grounds that it overcompensates embedded generators for their locational decision and thus provides them with a competitive advantage over transmission connected generation. The NGF argues that embedded generators should receive only the real cost savings it imposes on the transmission network.

In section 4.2 of this determination, the Commission has required transmission usage prices be re-calculated annually, thus ensuring that, over time, the size of the rebates to embedded generators will take into account evolving circumstances such as the actual levels of load growth and the advent of other embedded generators.

The Newcastle Group raises a further issue regarding the interaction of the regulatory test and the likely future savings in augmentation associated with embedded generators,

However, while the regulatory test will determine whether a particular network augmentation is justified, it bears little relationship to the actual use of the transmission network. As embedded generators may change the pattern of use of the transmission network, reducing a DNSP's usage charge contribution, it is logical that this saving be passed to the embedded generator that creates it.

QLD Treasury notes that over-signalling could still arise unless embedded generators pay the full costs of connection.  It recommends that rebates should be conditional on generators entering into availability commitments and performance requirements so as to ensure reliability of supply is not compromised.  The Commission agrees that for efficient outcomes, each embedded generator will need to be exposed to a suite of signals that reflect all the costs and benefits that the generator confers on transmission and distribution systems, as well as the energy market.  The transmission usage rebate will be one component of that suite of signals, and given that it will be recalculated each year, the rebate offered will reflect the extent to which the operation of the embedded generator supports the network.  It should ensure that the generator locates and operates so as to support the transmission system, to the extent it is cost-effective to do so.  Connection costs would normally be considered as part of the negotiation of a connection agreement.  That negotiation should also provide an opportunity to consider additional incentives for the generator to operate so as to support reliability within the distribution network, if cost-effective.

The Commission agrees with Powerlink's and VENCorp's concerns that the proposed arrangements may create perverse incentives for generators to locate within the distribution network.  The Commission considers that the proposed changes may place an incentive on a large local generator to locate within a distribution network in order to receive the TUOS pass through even when, from a system wide perspective, it is more beneficial for it to connect to the transmission network.  This outcome reduces the public benefits of the NEM arrangements because generators may make inefficient locational decisions in order to get a TUOS payment.  However, the most satisfactory solution to this issue is likely to come from further integration of transmission signals into the energy market, as reflected by condition C4.2.  This would improve price signals to all market participants and reduce reliance on measures such as TUOS rebates to embedded generators.

The AEA, ACF, AGO and Stanwell advocate that embedded generators should also be entitled to a rebate of avoided general charges and common service charges.  As discussed in section 4.3 of this determination, the general charge is essentially a mechanism for recovering the balance of allowed revenue in a minimally distorting fashion.  The general charge relates to sunk network costs, which are not directly affected by whether an embedded generator connects to the distribution or transmission network.

Therefore, on the grounds that embedded generators are only compensated for the costs that they avoid, the Commission considers they should not receive a pass through of the TUOS general charge.  This also ensures the incidence of sunk costs does not distort investment signals between embedded generators and transmission connected generators.

The AEA argues that denial of a full rebate is inequitable and discriminatory in that it enables a regulated monopoly to recover costs for a service that it provides, yet artificially reduces the value of the same service if provided by an alternative means.  It suggests that denial of a full rebate will motivate generators and customers to bypass the network completely, unnecessarily stranding distribution networks.

The Commission agrees with the principle that equivalent services should be similarly valued. However the code has a number of provisions that should mitigate against the discrimination postulated by the AEA. Regulated investments must pass a regulatory test that is intended to ensure that they will only proceed if benefit-maximising or the most cost-effective means of maintaining supply reliability. Subsequently, the revenue entitlement is subject to review on the basis of optimised deprival value.

*Conclusions*

The Commission is of the view that the provisions for embedded generators to receive rebates of avoided transmission usage charges will be of net public benefit until such time as arrangements are developed for charging generators for new transmission investments.

The Commission notes however that the Code changes to clause 5.5 refer to 'TUOS usage' charges, which will not come into use until jurisdictional derogations to chapter 6 expire, a process that will not be complete until the end of 2002. The Commission has therefore imposed a condition of authorisation (C9.1) that the wording of the proposed code change must be amended to ensure it operates in the interim in a way that mirrors its long-term effect.

In the longer run the Commission considers that the continuation of rebates to embedded generation could over-signal if they are used in conjunction with arrangements for allocating the cost of new investments to all network users. However, in the short term it is unlikely that the arrangements for allocating the cost of new investment will provide the bulk of transmission price signals and hence a continuation of the usage charge rebate may be warranted. The Commission has therefore imposed a condition (C9.2) that the payment of avoided TUOS usage charges to embedded generators must be reviewed before the implementation of any new arrangements that allocate network charges to generators.

## 9.6 Conditions of authorisation

**C9.1 The proposed clause 5.5(i) must be replaced with words substantially equivalent to the following:**

**To calculate the amount to be passed through to an *Embedded Generator* in accordance with clause 5.5(h), a *Distribution Network Service Provider* must if *transmission usage prices* were in force at the relevant *transmission connection points* throughout the relevant *financial year*:**

**(a) determine the transmission usage charges that would have been payable by the *Distribution Network Service Provider* for the relevant *financial year* if the *Embedded Generator* had not injected any energy at its *connection point* during that year;**

**(b) determine the amount by which the charges calculated in (1) exceed the transmission usage charges actually payable by the *Distribution Network Service Provider*, which amount will be the relevant amount for the purposes of clause 5.5(h);**

**else the *Distribution Network Service Provider* must apply an equivalent procedure to that component of its transmission charges which is deemed by the relevant *Transmission Network service Provider* to represent the marginal cost of transmission, less an allowance for locational signals present in the spot market.**

**C9.2 The code must be amended to require NECA to review the arrangements for the pass through of avoided TUOS usage charges to embedded generators before the implementation of any new arrangements that allocate network charges to generators.**

# 10. Market network service providers

Market network services are defined as non-prescribed network services, operating between two connection points assigned to different regional reference nodes. That is, a market network service will interconnect two regions and is not eligible to earn regulated revenue under chapter 6 of the code.

The previously authorised version of the code only provides a skeletal treatment of the arrangements for market network services. The proposed changes, granted interim authorisation by the Commission on 6 October 1999 and 25 February 2000, provide one possible set of arrangements while leaving scope for alternative arrangements to be developed in the future.

## 10.1 Overview of the proposed arrangements

The proposed arrangements provide for investments in market network services to be supported by the revenue stream generated by trading electricity between the two interconnected regions. The parties to the investment will bear the risks associated with arbitraging electricity prices between the two regions. The MNSP can manage the risks by earning revenue in the following ways:

- acting as an electricity merchant - buying electricity in the low price region and selling it in the high price region. The price differential multiplied by the volume of electricity traded provides the MNSP with the revenue needed to support the investment; or

- underwriting the investment by selling the rights to the revenue generated by trading electricity across the interconnector. Purchasers of such rights include electricity retailers, traders and generators; or

- selling a physical trading product, that is the right to bid the capacity into the market; or

- entering into contracts with NEMMCO for provision of ancillary services or reserve trader services.

The proposed arrangements are based on a set of defined requirements - described as safe harbour provisions - that a network service must meet to be classified as a market network service. The proposed arrangements also allow for a network service to apply to NECA for derogations from any of the safe harbour provisions.

The 11 safe harbour provisions underpinning the changes to the code are:

- the interconnector must comprise a single two-terminal element of at least 30 Mega volt ampere (MVA) capacity that directly connects networks in different price regions;

- the interconnector must be scheduled and subject to analogous rights and obligations to those applicable to scheduled generators and loads;

- the MNSP is entitled to revenue from buying and selling energy in two regions and from providing ancillary services;
- flow through the interconnector must be independently controllable if the interconnector forms part of any network loop;
- the MNSP must bear the full cost of dedicated connection assets plus other network charges and rebates necessary for efficient investment and utilisation signals;
- the MNSP must enter into a connection agreement with the interconnected network in each region;
- the MNSP must pay for services to support the operation of the interconnector as well as compensate for any adverse impact on other parts of the network;
- NEMMCO's powers to direct the MNSP will be the same as its powers to direct other scheduled plant and the MNSP will be entitled to similar compensation;
- some, or all, of the MNSP capacity may be used for a reserve trader contract;
- the MNSP can apply to convert to regulated status at any time; and
- the MNSP must submit a code consistent access undertaking to the Commission.

In this section the Commission considers the overall proposal to allow MNSPs to participate in the NEM, and the safe harbour model as a whole. Specific changes to the code are discussed in detail in later sections of this chapter.

### 10.1.1 Issues for the Commission

The Commission must consider whether the proposed arrangements for the provision of market network services in the NEM generate public benefits such that the arrangements should be granted authorisation. Further, the Commission must consider whether the proposed arrangements for market network services results in a benefit to the public that outweighs any public detriment arising from a lessening of competition due to the introduction of market network services.

### 10.1.2 What the interested parties say

TransEnergie and BDB generally support the proposed safe harbour provisions although they have some specific concerns regarding some of the detail of the code changes. However, TransGrid, Powerlink and ElectraNet are less in favour of allowing market network services, and of the proposed safe harbour provisions.

TransGrid and Powerlink do not support the proposed safe harbour provisions, and state that the proposed arrangements will only result in a marginal increase in competitive pressures on existing generators, and expose end users to use of market power by MNSPs. TransGrid argues that unregulated interconnectors will not lead to socially optimal outcomes, and owners of MNSPs will capture any benefits of such developments. ElectraNet also considers that the public benefits of the proposed arrangements will be less than the public benefits that may accrue if regulated interconnectors were developed instead of market network services.

Further, TransGrid considers that the relative administrative simplicity of the proposed safe harbour model will bias investment decisions towards market network services, and may provide a tool for ‘spoiling’ approvals of regulated interconnectors.

### 10.1.3 What the applicant says

NECA states:

> The provisions to allow market network service providers to enter the market, where they meet the safe harbour provisions, adds new competitive pressures to generators at the expense and risk of the entrepreneur rather than customers.

### 10.1.4 Issues arising from the draft determination

In the draft determination the Commission supported the safe harbour provisions for the introduction of MNSPs to the NEM and proposed the following conditions of authorisation:

**C10.1 Clause 5.2.3(h) must be amended to revise the deadline to 12 months after the ACCC’s authorisation of the network pricing and MNSP Code changes take effect; and to require NECA to develop Code provisions to address the financial risks to a MNSP that arise as a result of a request for connection to a network which is used for the provision of market network services.**

**C10.2 Clause 5.5A of the Code must be amended to require DNSPs to pass through to an MNSP the TUOS savings that arise from the MNSP being connected to the distribution network. The amendments to the Code must be based on the provisions for embedded generators in clauses 5.5(h) and (i).**

**C10.3 Clause 6.1.4A must be amended as follows:**

**(a) Chapter 6 does not govern the principles or rules for the calculation of prices that a market network service provider may charge for its services.**

**(b) Until 31 December 2002, chapter 6 does not govern the principles or rules for the calculation of prices for transmission and distribution services provided by a network service provider to:**

**(1) a market network service provider; or**

**(2) another network service provider for electricity delivered to a market network service provider through the network of the other network service provider (except for any such electricity that is**

**ultimately consumed within the other network service provider's network).**

(c) **Until 31 December 2002, charges for the network services referred to in clause 6.1.4A(b) are governed by the provisions of clause 5.5A only.**

**C10.4 Clause 6.19(a) of the Code must be amended to refer to 31 December 1997, the date of effect of the Commission's first authorisation determination in respect of the Code.**

Delta Electricity (Delta) and the Newcastle Group believe that the public benefits of the MNSP regime as placed before the Commission do not outweigh the lessening of competition when compared to the alternate regulated regime. They contend that a single MNSP may be incompatible with an open access/common carriage regime and may lock out future regulated link development between the regions.

Delta states that if the MNSP regime is authorised, the public benefits test for regulated interconnectors should differentiate:

- the capacity offered by a free flowing regulated link from that offered by a MNSP;
- the constant behaviour of a regulated link from the variable competitive response of a MNSP across a range of market conditions;
- the impact on utilisation of national resources, including investment and interstate trade, of the two regimes; and
- between the economic outcomes of MNSP tolling and regulated tariffs.

Delta and TransGrid contend that if the MNSP regime is authorised then these arrangements should be monitored closely by the Commission following their introduction and the framework should be reviewed in 2 years time examining the principles of their operation, economic outcomes and net public benefit.

NSW Treasury states that one of the purported benefits of MNSPs is that risks and costs associated with the investment are borne by the investment proponents, rather than customers under a regulated regime. However, NSW Treasury argues that TNSPs bear the risk of optimisation of regulated interconnectors.

NSW Treasury and TransGrid contend that the Commission has not made a clear public benefit case for the authorisation of MNSPs on the present terms due to the ability of market participants, including generators and MNSPs to 'game' the approval process for regulated interconnectors to protect their own commercial positions.

Delta, NSW Treasury and the Newcastle Group all believe that market network service proponents should lodge some sort of bank guarantee, bond or non-refundable deposit with an independent body. They state that this would give proponents an incentive to provide accurate information regarding the prospects of development of a market network service and thereby minimise the possibility of distorting or manipulating application of the regulatory test.

TransGrid believes that unregulated market network services are likely to create public detriment and should therefore not be authorised.  TransGrid states that this is because an MNSP will possess the market power that is intrinsic to any NSP, and will use this power to extract monopoly rent, to the detriment of the market and the public. TransGrid also states that an MNSP will not enter into long-term contracts if these diminish its revenue-earning capacity and therefore any long-term contracts will not diminish market power, but will simply lock the value of that market power into the contract price.  TransGrid considers that MNSPs will not create additional interconnections between regions, but will simply displace future regulated interconnections that would have brought greater public benefit.

The AEA supports market based outcomes rather than regulated transmission investments.  QLD Treasury supports the safe harbour provisions for MNSPs and agrees with the Commission's conclusions on the safe harbour provisions.

TransEnergie states that the market accepts none of the risks associated with investment in market network services while the market both pays for regulated network services and also accepts the risks associated with regulated network services.  TransEnergie believes that these factors justify differences between the frameworks for approval of regulated and market network services.

TransEnergie agrees with the Commission's position regarding the benefits of the risk allocation framework associated with MNSPs, however disagrees that 'the proposed arrangements may be sub-optimal' when compared to regulated network investments. TransEnergie considers that this statement does not take into account the uncertainties of competitive markets and assumes that a NSP is still performing a central planning function for a vertically integrated utility.

TransEnergie argues that in the competitive market new generation is planned by independent power producers in response to market price signals and that the NSP has little or no information regarding the location or level of operation of such facilities. TransEnergie states that this is complicated because the level of operation is determined by competitive bids and the required level of capacity has a high degree of uncertainty. TransEnergie believes that in that environment the NSP planning regulated network investments no more has a 'crystal ball to predict the future' than does the MNSP, and consequently, can no more build an 'optimal investment' than any other developer.

TransEnergie contends that the uncertainties of competitive markets also mean that regulated NSPs will increasingly aim to match the size of new regulated investments to the needs of the market.  If regulated investments continue to be overbuilt (with surplus capacity) the NSP runs the real risk that the market will not need the surplus capacity and the NSP will not be able to earn a return on its stranded investment.

TransEnergie states that market network services provide public benefits through promotion of competition leading to increased efficiency that in turn will promote industry cost savings.

### 10.1.5 Commission's considerations

The Commission notes that the code has always envisaged the development of market network services (previously called non-regulated or entrepreneurial interconnectors). However, the existing code provisions provide little detail about how market network services will operate in the NEM, apart from the non-application of the Chapter 6 pricing and revenue control principles. Therefore, the Commission welcomes NECA's proposals establishing the ground rules for MNSP participation in the NEM.

The Commission considers that MNSPs will operate in the NEM as network elements and the benefits from their introduction will arise from the potential for greater trade of electricity between regions. To the extent that a MNSP injects capacity into a region, the market network service is providing a source of competition for generators in the importing region. Further, where a MNSP offers financial hedges to NEM participants, inter-regional trade will be facilitated, providing a further benefit to the NEM.

In this context the Commission does not consider that the introduction of MNSPs to the NEM will result in a public detriment due to a lessening of competition. However, in some situations the Commission is aware that the operation of a market network service may detract from the public benefits that could otherwise be expected.

The Commission recognises that the incentive placed on the proponents of a market network service may be to preserve price differentials between regions. Interested parties claim that MNSPs will have an incentive to either construct a link of smaller than socially optimal capacity and/or restrict flows between the regions. As such the expected public benefits that could arise from the introduction of market network services may not be fully realised. An MNSP may bid its capacity into the NEM at high prices, though such strategies will be constrained by the bid prices of competing generators and interconnectors. As such the MNSP will possess a degree of market power or may enhance the existing market power of other NEM participants and may be able to influence spot prices, especially by withdrawing capacity from the spot market.

The Commission believes that when an MNSP has an incentive to limit the capacity of a link to preserve inter-regional price differentials, this is similar to that of a new generator who would not want to over invest in capacity leading to a collapse in its regional spot price. In this context, the Commission notes that new generators avoid this risk by writing long term supply contracts to get a secure income stream and hedge against the risk of a decline in prices. Similar contracting arrangements are also open to MNSPs, who could sell the rights to inter-regional revenues to generators that want to export electricity to another region. Such a long term contract could be similar in form to a transmission congestion contract (TCC).

The ability of the MNSP to restrict flows in order to raise prices is also analogous to generators withdrawing their capacity from the market. The success of such strategies is heavily dependent upon the nature of any financial contracts that the MNSP (or generator) may have and will diminish over time as more capacity enters the market. Further in most cases the incentive to withdraw capacity will be muted where the proponents of market network service have sold the rights to the revenue stream, with the incentive dampened the most where long term contracts provide the bulk of the

MNSP's revenue. However, in instances where an MNSP has the ability to impact spot prices the incentive to withdraw capacity may remain. The Commission also notes that in some circumstances the commercial relationships between an MNSP and another market participant may be an issue.

The Commission is aware that NECA has undertaken some analysis on bidding and rebidding behaviour in the NEM and notes that the proposed changes arising from that review will apply equally to MNSPs and generators. Therefore the Commission does not believe any specific conditions addressing market power are required at this time. However, there are situations where an MNSP may be used to influence overall competition in a region. In such situations the Commission considers that it is prudent to ensure the safe harbour provisions proposed by NECA minimise the potential for anti-competitive detriment. The Commission notes the recent report from FERC with respect to a proposed merchant link 'Project Neptune'. In the FERC order approving the proposal, FERC used a number of criteria to assess the proposal, including that the merchant transmission facility should:

- assume full market risk;
- create tradeable transmission rights and an open season process should be employed to initially allocate transmission rights;
- not preclude access to essential facilities by competitors;
- be subject to market monitoring for market power abuse;
- coordinate physical flows with the relevant ISOs; and
- not impair pre-existing property rights.

FERC then addressed issues of concern in the Neptune proposal, and imposed a number of requirements upon the proponents of the link, such as:

- refusal to allow bilateral negotiation for property rights prior to the initial open season allocation;
- refusal to compel payments for system benefits;
- agreeing to the proposed restriction on affiliate participation in the open season; and
- a requirement to comply with data requests from market monitoring authorities.

The Commission notes that where significant market network services are proposed in the NEM it may be appropriate to consider similar arrangements, to meet market power concerns. This issue is further addressed below, in the section on MNSP access undertakings.

The Commission believes that market network services will provide a source of competition for generators in an importing region and that investment and bidding decisions are likely to face similar incentives. Further, the Commission notes that where market network services are constructed the risks and costs associated with the investment fall upon the proponents of the service, rather than customers and TNSPs, as is the case with regulated investments. Thus the Commission considers that public benefits will arise from the increased competition and availability of electricity in the importing regions compared to the pre-existing circumstance where the market network services do not exist.

The Commission accepts Delta's argument that the possibility of a market network service being developed should not be sufficient to prevent a regulated network service from going ahead. Delta suggests that MNSPs should be required to lodge some form of bond to signal the seriousness of the project. However the Commission believes that if a proposed MNSP is required to put up a bond then an equivalent obligation should also be applied to all other proposed alternatives including generation. Further, the Commission considers that this raises issues regarding what can be considered as a committed project under the regulatory test and the Commission is of the view that this issue is better addressed in the context of the review of the regulatory test. That review will consider the issue of how to assess the likely impact of a market network service project that is not completed, or the expected benefits of a proposed regulated link. Some form of probabilistic assessment of completion of a market network service may be required, and in that context the possibility of requiring bonds or deposits of market network service proponents can be considered. The Commission will review the regulatory test later in 2001.

Overall the Commission supports the introduction of market network services and the safe harbour provisions as proposed, subject to the conditions discussed in the sections below. The Commission considers that sufficient public benefits are likely to arise to justify authorisation of the proposed code changes.

## 10.2 Registration of MNSPs

The proposed changes in chapter 2 of the code set out the arrangements for registration as an NSP and classification of network services as market network services. The requirements include that MNSPs must register with NEMMCO, and satisfy NEMMCO that:

- they meet the prudential requirements;
- they meet any requirements placed upon them by Jurisdictional Regulators;
- they do and will continue to comply with the code; and
- they have paid the relevant fees.

Further as an NSP, the MNSP is required to lodge an access undertaking with the Commission, and if registered as a market network service must also be registered as a scheduled network service.

Specific amendments to clause 2.5.2 of the code reflect many of the safe harbour provisions, including the technological requirements, the requirement to submit an access undertaking to the Commission and the option of converting a market network service to a prescribed service.

### 10.2.1 Issues for the Commission

The requirement to register and the eligibility requirements could be considered to be:

- exclusionary provisions, as competing participants agree not to trade with unregistered persons;
- exclusive dealing provisions, as participants in the market agree to trade on condition that they will not supply electricity to, or acquire electricity from, unregistered persons; or
- provisions having the purpose or effect of substantially lessening competition, as the requirement to be registered before being entitled to trade might act as a barrier to entry to the relevant market.

### 10.2.2 What the interested parties say

TransGrid, Powerlink and ElectraNet all express concern that the opportunity to convert market network services to prescribed network services offers an opportunity for MNSPs to bypass the regulatory test to which new regulated interconnectors are subject.

TransGrid further notes that reopening the revenue cap for an NSP is only allowed in certain limited circumstances. Hence allowing the relevant regulator the discretion to adjust the revenue or price cap of the newly prescribed network service may not reflect the provisions of chapter 6 of the code. TransGrid states that clause 2.5.2(c) should be reworded to refer to adjusting the revenue cap or price cap to reflect relevant network assets, and associated costs such as operations and maintenance and depreciation costs.

TransGrid also raises the issue of conversion from prescribed network services to market network services. TransGrid states it is inequitable to prevent existing prescribed network services being reclassified as market network services and claims that there is no substantiated justification for the prohibition.

TransGrid also states that the proposed safe harbour provisions are not technologically neutral, noting that the requirement for independently controllable equipment excludes AC link options.

TransEnergie queries the need for MNSPs to register both as market participants and NSPs, believing the latter to be inappropriate. TransEnergie states that the arrangement may lead to unintentional obligations being imposed on MNSPs, and the access undertaking should be couched in terms that make it clear that obligations imposed on MNSPs are only imposed in relation to the provision of market network services.

BDB accepts the need for an access undertaking, but states that it should not be extended to include provisions such as access pricing provisions. BDB states that any competition law or market power issues should be dealt with through the provisions of the TPA, rather than the access undertaking, noting:

> A requirement by the ACCC to include pricing constraints in an access undertaking, which might translate into bidding limits for a MNSP and/or limits on premiums for

> inter regional hedge contracts, could potentially reduce the value of such an interconnector and therefore discourage its development.

SPI PowerNet states the requirement that market network services be independently controllable raises the costs of the privately funded interconnectors and may reduce the benefits provided by the interconnectors. SPI PowerNet notes that NECA's draft report observes that one of the issues raised by the working group is whether 'the need for non-regulated interconnectors to be independently controllable can be dispensed with by developing alternative approaches to eligibility to spot market revenue.'[25] Part of the motivation for making the line controllable is to limit the use of the line in order to maintain ex post price differentials that would be sufficient to support the unregulated transmission investment. SPI PowerNet considers that the alternative of using a TCC system would resolve this issue, without the need for market network services to be independently controllable. SPI PowerNet also states that

> … one of the reasons for the requirement for independent control is the issue of loop flow. The very realisation of the loop flow problem further supports the benefits of a TCC-based system with locational pricing (which eliminates the artificial requirement for a controllable link) and, as stated above, the resultant higher cost and less transfer capability than a similar AC link.

### 10.2.3 What the applicant says

NECA argues that the complexity of reviewing and approving interconnector schemes of smaller than 30 MVA may outweigh the benefits and the 30 MVA threshold is consistent with the current provisions in the code for generation. Further, NECA notes that intra-regional schemes are not feasible at present and that multi-terminal topology would create additional complexity in devising market rules.

Previously NECA has also argued that the registration requirements in general are an essential element for the orderly functioning of the NEM. In particular, NSPs need to be bound to the code in order to preserve the integrity of the power system and ensure public safety (see National Electricity Code Determination 10 December 1997).

### 10.2.4 Issues arising from the draft determination

BPL states that the access undertaking should be seen as an instrument to ensure that MNSPs will allow physical access or augmentation to their links, at such time that the code provisions are modified to require MNSPs to do so. BPL sees no reason to depart from the pro-forma access undertaking set out in the code.

BPL contends that it would be inappropriate to place restrictions on the bidding behaviour of the MNSP beyond those that apply to generators. To do so would undermine the whole philosophy of entrepreneurial links providing a source of direct competition to generators but would not preclude the Commission reviewing anti-competitive bidding behaviour by an MNSP.

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[25] NECA Draft Report, p. 88.

BPL considers that it would be inappropriate for the Commission to seek to impose any conditions on MNSPs (either through modified access undertakings or through other conditions) in an attempt to address concerns regarding the underlying competition issues within some jurisdictions.

BPL states that it is not clear whose interests the access undertaking protects. If a 2-way link is built connecting 2 regions in the NEM, competition in those regions will be enhanced. However, the construction of the link does not guarantee that a generator in one region will be able to sell its electricity into the other region. BPL submits that just as a generator connected to a TNSP's network is not guaranteed 'firm' access within a region, an MNSP link should not be seen to grant firm access to the generators located in the linked regions.

TransGrid states that if authorised, MNSPs should still be subject to appropriate access regulation. An option that should be considered is for MNSPs to be subject to the general application of Part IIIA of the TPA so that appropriate terms and conditions of access to the individual MNSP can be imposed.

TransEnergie believes that the draft determination does not consider in any real detail the rationale for an MNSP to submit an access undertaking and considers that this issue warrants further consideration.

### 10.2.5 Commission's considerations

The Commission acknowledges that the eligibility provisions outlined in the code assist in the orderly functioning of the market and therefore deliver considerable public benefits. The registration requirement helps achieve the binding effect of the code, and accordingly contributes towards preserving the integrity of the power system.

However, the entry conditions imposed by the code are a determining factor in the level of contestability in the NEM and will affect the magnitude of price benefits that may be passed on to consumers.

*Technical requirements*

The Commission notes the claims of SPI PowerNet and TransGrid that the technological requirements specified in clause 2.5.2 may increase the costs of interconnector provision, and may deter some potential MNSPs from entering the NEM. In particular, the Commission notes SPI PowerNet's discussion on the benefits of TCCs as an alternative model for market based network service arrangements and notes that it as an option that NECA can consider as part of RIEMNS.

However, the Commission accepts that the technical requirements specified for MNSPs are soundly based, and have been imposed with a view to either simplifying the connection procedures or minimising any adverse impact of market network services on existing NEM participants. The Commission understands that the requirement for market network services to be controllable is necessary if other elements of the transmission networks are to operate to capacity. Further, the Commission notes that new entrants may apply to NECA for a derogation from the registration requirements, and as such the technological requirements can be diluted, without undue administrative burden.

*Conversion between market and prescribed status*

In terms of overall philosophy the proposed arrangements to allow switching from a market to a prescribed network service seem at odds with the general direction of the market and the move towards greater provision of market based arrangements where possible. However, the Commission understands that the provision to allow market network services to apply for conversion to prescribed network services reflects the view that MNSPs may face risks from future NEM developments, such as changes to regional boundaries, which may result in market network services becoming non-code compliant. The Commission notes that as the clause is currently drafted no justification is required prior to reclassifying a market network service as a prescribed network service, although the regulator has the discretion to determine whether or not a network service may be classified as a prescribed network service.

The Commission notes TransGrid’s concerns regarding the prohibition on converting network services from prescribed status to market status (clause 2.5.2(a)(3)) and the inequity of only allowing market network services to be reclassified as prescribed network services (clause 2.5.2(c)).

However, the Commission agrees with concerns that allowing conversion from prescribed to market network services could allow incumbent NSPs to use such arrangements to gain windfall revenues, at the expense of other network customers. For example, an NSP may nominate only a very small element of its overall network for conversion to market status. This would enable a regulated revenue to be earned on the bulk of the infrastructure required to transport electricity across a regional boundary, at the same time as earning revenue from the provision of market network services. In such as case, the incumbent NSP would clearly have a competitive advantage over any other potential proponents of market network services between the same regions.

The Commission also has concerns that a regulated TNSP may be able to invest in a part of its network that appears unrelated to the MNSP, but which in reality may free up a network constraint so that increased flows can be exported over the MNSP.

The Commission considers that, particularly given the infancy of MNSPs in the NEM and the potential risk of gaming, it is inappropriate to allow prescribed interconnectors to convert to market network services. The Commission therefore supports NECA’s recommendation to prohibit conversion from regulated to market network service.

*Conversion process*

The Commission notes the concerns of several interested parties regarding the conversion of market network services to prescribed network services, in particular the process and degree of regulatory discretion.

The process set out in chapter 2 allows an MNSP to notify NEMMCO that the network services provided are no longer classified as market network services, and also allows the relevant regulator to determine if the network service is a prescribed network service.  Clause 2.5.2(c) also allows for the regulator to adjust the NSP's revenue cap or price cap in accordance with chapter 6.

Interested parties raise the issue of such a process enabling MNSPs to bypass the regulatory test that applies to new prescribed network services such as interconnectors, augmentations or augmentation options.  The process for establishing a new market network service is seen by some interested parties as administratively more simple than the process for establishing a new regulated interconnector.  The key concern appears to be that conversion from market to prescribed network services offers an administratively simple path to construct network services, which could then be allocated a regulated revenue stream, rather than remaining subject to market risks.

Clause 2.5.2(c) sets out an arrangement where the relevant regulator has a high degree of discretion regarding the classification of a network service as a prescribed service and determining the appropriate extent that a revenue cap or price cap is adjusted to reflect the newly prescribed services.

The Commission considers that as the nominated regulator for transmission assets, the Commission will generally be the relevant regulator exercising its discretion in regard to conversion of market network service to prescribed network services.  Where the Commission decides a network service may be a prescribed network service, an NSP will require a revenue stream to be determined for that service.  The Commission will consider the prudence of the network service at the time the conversion to a prescribed service occurs, rather than consider any earlier investment decisions.  As such the investor would bear the risk of the Commission optimising down the value of the assets - with the consequence of reduced revenue streams, at the time it converted to regulated status and at each regulatory review into the future.

The Commission considers many of the concerns raised by interested parties can be addressed by the Commission's *Draft Regulatory Principles.*

The Commission will consider any applications to convert from market to prescribed status on a case by case basis.  However, the *Draft Regulatory Principles* clearly set out the process that incumbent NSPs must follow at each regulatory review and applicants for conversion of network services to prescribed status will have to follow the same process.  The Commission will develop the *Draft Regulatory Principles* to set out the process and guidelines needed to formalise the conversion arrangements.

Further the *Draft Regulatory Principles* set out that a DORC valuation will be used to value (or revalue) the asset base of the NSP.  The Commission considers that the DORC valuation allows for consideration of all possible options for replacing existing network services, as well as consideration of current and future utilisation rates.  The effect of a DORC valuation will be that the network is valued to reflect the least cost solution to resolve any demand and supply imbalance needing to be addressed.  Thus the process of changing status of network services requires the NSP to submit to a valuation process that delivers outcomes consistent with the intent of the regulatory test. The processes set out in the *Draft Regulatory Principles* may be simpler than the regulatory test processes but the Commission considers that no material advantage will accrue to NSPs converting from market to prescribed status through bypass of the regulatory test.

*Requirement to submit an access undertaking*

The proposed changes set out the requirement for each MNSP to provide an access undertaking to the Commission. The form of the access undertaking is set out at schedule 5.8, which requires each NSP to provide access to code participants in the manner specified in the code. In the original authorisation of the code (10 December 1997) the Commission accepted the requirement that all NSPs must submit an access undertaking in order to register, since it provides code participants with transparency and certainty about the obligations of NSPs.

When considering access to market network services, the relevant service, for the purpose of Part IIIA of the TPA, is the transmission of electricity across the interconnector. The Commission recognises that the existence of a market network service does not grant firm access rights to participants in either region. The terms and conditions for access to market network services by the market as a whole are generally covered by the wholesale spot market rules in chapter 3 of the code, that is the rules for bidding the market network service into the market to be dispatched by NEMMCO.

However, the structural and/or market arrangements in the regions that a market network service links will have a bearing on how the terms and conditions for access are determined. This may result in the effective price of access to the market network services being determined without the benefits of competitive pressures.

While the Commission firmly believes that MNSPs should submit an access undertaking, it notes that the pro-forma access undertaking set out in schedule 5.8 is not sufficient for MNSPs. For MNSPs chapter 3 of the code (which is not part of the access code) is fundamental to determining the terms and conditions of access to the services provided by an MNSP.

Therefore the Commission has imposed a condition of authorisation (C10.1) requiring the inclusion of a proforma access undertaking specific to MNSPs in the code, and amending the clauses referencing the access undertaking. The MNSP access undertaking must specifically refer to the pricing provisions of chapter 3 of the code. Before accepting an access undertaking the Commission may require additional information depending on the structure and market arrangements in place, such as information regarding access pricing, affiliate rights. Further the Commission reserves the right to impose additional requirements on the access undertaking to enhance the market benefits of an MNSP.

Further, section 44ZZA(4A) of the TPA exempts the Commission from publishing the undertaking and inviting interested parties to make submissions if that undertaking is in accordance with an access code that is in operation at the time of acceptance. The Commission would therefore need to conduct public consultation before accepting an MNSP's access undertaking. This would also be necessary if the undertaking included additional information.

The Commission notes that even if the requirement to submit an access undertaking were removed, market network services would still be subject to the risk of declaration under Part IIIA. The Commission considers that the risk of declaration introduces an uncertainty about access outcomes and the consistency with the code and believes that it is better to retain the requirement to submit an appropriately worded access undertaking that includes an undertaking to comply with all relevant code provisions. The extent of the risk of declaration will depend on the significance of the MNSP to the regions it is connecting. In the case of an immaterial link, a standard form of access undertaking may be sufficient. However for a material link the access undertaking may need to include explicit provisions governing the operating of the service.

***Condition of authorisation***

**C10.1 A new proforma access undertaking must be inserted into the code and the code must be amended to require MNSPs to submit the new proforma access undertaking, rather than the access undertaking in schedule 5.8.**

## 10.3 Network connection and network charges applicable to MNSPs

The proposed arrangements for network connection set out the rights and obligations of MNSPs seeking access to the networks that form the national grid. Further the proposed changes clarify the obligations of existing NSPs from whom network connection is sought.

### 10.3.1 Issue for the Commission

The technical requirements for network connection may be considered to deter or limit entry to the NEM and may be exclusionary provisions or may substantially lessen competition. The proposed arrangements restrict access to MNSPs networks, which may distort investment decisions and require MNSPs to negotiate with incumbent monopoly NSPs that may be costly, difficult and protracted. These arrangements may detract from potential public benefits.

### 10.3.2 What the interested parties say

TransGrid argues that MNSPs are customers in the exporting region and generators in the importing region and NSPs in between. TransGrid states that as customers they should pay all customer TUOS costs. TransGrid argues that as regulated interconnectors effectively bear TUOS costs (which are passed through to end users) it follows that market network services also should pay TUOS.

However, BDB strongly supports the proposed arrangements and argues that in no circumstances should an incumbent NSP be able to charge an MNSP for:

- common service charges;
- customer TUOS usage charges;
- customer TUOS general charges; or
- generator TUOS charges.

BDB states that allowing recovery of any of these charges from an MNSP would constitute discriminatory treatment vis-a-vis regulated interconnectors and would not create efficient economic signals or achieve the goal of a level playing field. BDB argues that to drive the best economic decisions, MNSPs should be considered as a transmission element which derives its revenue from operating in the market, rather than a generator/load pair. Hence, BDB considers that only three components of TUOS charges should be able to be levied on MNSPs:

- shallow connection costs (ie. the equivalent of entry and exit charges);
- negotiated use of system charges, which reflect both the benefits and costs associated with the impact of the MNSP project on the incumbent NSP networks (see draft clause 5.5A(g)(2)); and
- amounts agreed with incumbent NSPs associated with the provision of MNSP access (ie. firm access arrangements to be negotiated with interconnected NSPs in the same way that generators may undertake such negotiations).

BDB states:

> the payment of TUOS charges should be a matter for fair and reasonable negotiation between the developer and the relevant NSP based on the marginal cost and value of transmission at the relevant connection points. This was the approach agreed by the Working Group for Entrepreneurial Interconnectors and is generally consistent with the provisions in Clauses 6.4.3 and 5.5A of the code changes now before ACCC.

TransEnergie and National Grid do not support the inclusion of network augmentation compulsion powers (clause 5.2.3(h)) and argue that a better model would be allowing for commercial negotiation. However, TransGrid considers that the delay in developing the code provisions to address the issue of financial risk to MNSPs when augmentations are required has the effect of negating the access undertaking.

Both TransEnergie and National Grid argue that where augmentations are needed, provided the requirements for new regions as specified in the code are met, then a new region should be established so that market network services can also be considered as an option for resolving augmentation needs.

Further, TransEnergie and National Grid also state that it is inequitable for MNSPs to have to negotiate TUOS benefits (clause 5.5A(g)(2)), when the code specifies that generators are entitled to TUOS benefits.

TransGrid also has problems with the intent and drafting of the TUOS benefits clause, noting that as drafted it does not make clear what amount is to be passed through to MNSPs. However, TransGrid considers the underlying presumption that MNSPs may cause an augmentation to be avoided is flawed. TransGrid states that an NSP could only avoid an augmentation of its network if the capacity supplied by the market network services were subject to a network support arrangement, as in any other situation the capacity could be withdrawn from the market at any time by the MNSP. TransGrid considers that the need for a network support agreement renders the code provisions regarding TUOS pass through redundant.

ElectraNet strongly disagrees with the residual responsibility placed upon TNSPs in schedule 5.2 and schedule 5.3a of the code, which require them to provide communications systems between a local site to the control centre. ElectraNet considers the provision of such communications services to be contestable and believes that the associated risks should be the responsibility of the market participant and not the TNSP.

Further ElectraNet believes that any revenue a TNSP receives for delivering a higher negotiated service standard should be in addition to the regulated aggregate annual revenue requirement.

### 10.3.3 What the applicant says

NECA states that the requirement on MNSPs to enter into connection agreements will give them comparable rights and obligations to that of a generator in negotiating access arrangements. NECA also states that the exposure to other network charges and rebates should be to the extent necessary to provide efficient investment and operational drivers.

NECA argues the appropriate TUOS charges at the interconnection point of a market network service are the marginal costs of transmission, as identified in the TNSPs pricing methodology. These charges should provide efficient investment and operation signals to proponents of market network services. NECA also notes that MNSPs should not be required to pay TUOS charges that materially disadvantage them in comparison to regulated interconnectors, and hence MNSPs should not be required to pay the residual TUOS charges.

### 10.3.4 Issues arising from the draft determination

In its draft determination the Commission imposed the following conditions of authorisation:

**C10.1 Clause 5.2.3(h) must be amended to revise the deadline to 12 months after the ACCC's authorisation of the network pricing and MNSP code changes take effect; and to require NECA to develop code provisions to address the financial risks to a MNSP that arise as a result of a request for connection to a network which is used for the provision of market network services.**

**C10.2 Clause 5.5A of the code must be amended to require DNSPs to pass through to an MNSP the TUOS savings that arise from the MNSP being connected to the distribution network. The amendments to the code must be based on the provisions for embedded generators in clauses 5.5(h) and (i).**

The Commission's draft determination also required that TUOS usage charges or rebates be levied on all network users including MNSPs, according to whether they add to or relieve network congestion.

QLD Treasury agrees with the Commission's comments that there should be equality between MNSPs and embedded generators in terms of transmission usage rebates, similar to embedded generators, these should be limited to MNSPs below a threshold size. For equity reasons, QLD Treasury would support a recommended size limitation of 30MW for MNSPs to be eligible for transmission usage saving rebates. In making this recommendation, QLD Treasury notes that the safe harbour provisions limit minimum MNSP capacity to 30MVA and, therefore, only a limited number of MNSPs will meet the eligibility requirements for transmission usage savings rebates. However, QLD Treasury maintains support for its proposed limits on equity grounds.

QLD Treasury supports the Commission's view that there should be equitable treatment between MNSPs and other market participants and between MNSPs and regulated network services. QLD Treasury supports the view of the Commission in respect of levying TUOS on MNSPs but does not support the Commission's proposed approach to transmission usage charges. QLD Treasury's view is that the development of any new arrangement must ensure that MNSPs pay transmission network charges where applicable. QLD Treasury notes that the existing arrangements need to be updated to ensure that MNSPs pay TUOS where they act as a load and that the Commission should address this issue in its final determination.

QLD Treasury contends that it is important that MNSPs and embedded generators are required to bear the costs of network augmentation that arise from the connection to the network. This is particularly important when it is considered that embedded and transmission connected MNSPs can result in both high cost augmentation in the distribution network as well as lead to transmission network augmentation if the MNSP acts to increase congestion on the transmission grid.

Tarong agrees with the Commission's proposal to make MNSPs subject to the same TUOS usage charge regime as scheduled generators. However, Tarong believes that the Commission should recognise that MNSPs are subject to the same constrained off risks to that which scheduled generators are exposed. Thus any usage charge regime for MNSPs must take account of the existing congestion related signals they are already exposed to, such as constraining off risk.

TransEnergie supports a framework in which market network services incur a charge where they add to congestion, and a rebate where they relieve congestion and states that this should impose a zero network charge on an efficient market network service. However perverse network pricing signals can arise if network charges are not determined by a central authority applying a consistent methodology across all market regions.

NECA states that even having regard to the doubtful effectiveness of a requirement for distribution service pricing to preserve the economic signals of TUOS pricing, the congestion based TUOS pricing method results in the loss of the TUOS saving or TUOS pricing signal where congestion is removed by an MNSP.

Other general comments about the Commission's proposed TUOS usage price regime are detailed in chapter 4 of this determination.

### 10.3.5 Commission's considerations

*Levying TUOS*

The Commission supports the underlying goal of the proposed arrangements for levying TUOS, that is a set of arrangements that supports efficient investment and operation decisions. The Commission also considers it appropriate that the network charges levied try to capture the marginal costs of using a market network service. However, the Commission is also concerned to ensure that there is equitable treatment between MNSPs and other market participants (where MNSPs are acting as market participants), and between MNSPs and regulated network services. However, the Commission considers that it is appropriate to treat MNSPs generally as an alternative form of network service, rather than as a generator/load pair. This is consistent with the need for the MNSP to submit an access undertaking to the Commission.

As discussed in section 4.2 of this determination, the Commission has withdrawn the conditions proposed in the draft determination that levy TUOS usage charges or rebates on MNSPs and generators.

With respect to TUOS general charges, the Commission recognises the potential distortions to investment decisions and the inequity between regulated and unregulated interconnectors that may arise from levying these charges on MNSPs.

*Connection and augmentation*

Clause 5.2.3(i) sets out that MNSPs are not obliged to comply with any network connection or augmentation request, until such time as the financial risks facing the MNSP in such a circumstance are addressed by NECA. Clause 5.2.3(h) requires NECA to develop code provisions to address financial risks faced by an MNSP when it is required to augment its network to support an augmentation to the national grid that is approved in an NSP's annual planning review. These code provisions are to be developed within two years of market commencement.

The effect of clause 5.2.3(i) is to disallow other parties the right to physically connect to an MNSP's network. The Commission notes the concerns of TransGrid regarding this matter but considers the arrangement is transitional. However, as currently worded clause 5.2.3(h) only requires NECA to consider the financial risks arising from network augmentation. The Commission considers that the clause should be amended to require NECA to also address the financial risks that may arise from any request for connection to a market network service.

The code provisions referred to in clause 5.2.3(h) are to be developed within two years of market commencement, ie. by December 2000. This timetable is not now realistic. The Commission therefore now requires that NECA must develop the code provisions referred to in clause 5.3.3(h) within 12 months of the date of effect of the determination.

*TUOS benefits pass through*

The Commission notes the code's treatment of MNSPs is not equivalent to the treatment of embedded generators, in terms of the provisions for the pass through of TUOS savings. The key difference is that while clause 5.5(h) specifies that the DNSP *must* pass through the TUOS savings to an embedded generator, clause 5.5A(g) only provides for negotiations in good faith regarding any use of system payment to be made by the relevant NSP to the MNSP. Given the difficulties that many businesses experience when trying to negotiate terms with incumbent monopoly service providers the Commission considers that the code should unambiguously provide for the pass through of any benefits that the MNSP delivers to the network.

The Commission therefore imposes a condition of authorisation that provisions must be inserted into the code, akin to those for embedded generators, that require DNSPs to pass through any TUOS savings arising from the connection of an MNSP within its area.

*Responsibility for communications systems*

The Commission considers that ElectraNet's concerns have some merit but notes that the issue of the contestability of the provision of communications systems is an issue being considered by the Market and System Operating Review, conducted by the jurisdictions.

*Service standards*

The Commission notes the issue raised by ElectraNet and believes that the proposed treatment of negotiated higher levels of service standards set out in *Draft Regulatory Principles* is exactly as ElectraNet desire. That is revenues for premium service are treated as revenue from non-prescribed services, and capital and operating costs attributable to provision of the premium service are excluded from the revenue cap calculations.

### 10.3.6 Conditions of authorisation

**C10.2 Clause 5.2.3(h) must be amended to revise the deadline to 12 months after the ACCC's authorisation of the network pricing and MNSP code changes take effect; and to require NECA to develop code provisions to address the financial risks to a MNSP that arise as a result of a request for connection to a network which is used for the provision of market network services.**

**C10.3 Clause 5.5A of the code must be amended to require DNSPs to pass through to an MNSP the TUOS savings that arise from the MNSP being connected to the distribution network. The amendments to the code must be based on the provisions for embedded generators in clauses 5.5(h) and (i), as amended by condition C9.1.**

## 10.4 Application of chapter 6 of the code to MNSPs

The amendments to chapter 6 of the code, as proposed by NECA, were intended to exempt MNSPs from applying the code's provisions with regard to levying network charges for use of the market network service. Specifically, clause 6.1.2(e) explicitly excludes market network services from the network pricing arrangements specified in part F of chapter 6. Clause 6.1.4A (amended by NECA on 17 January 2000) sets out that:

- chapter 6 does not govern the principles or rules for the calculation of prices to be charged for market network services;
- the prudential requirements set out in clause 6.6 and 6.15 do not apply;
- the billing and settlements procedures set out in clauses 6.7 and 6.16 do not apply;

- software specifications set out in clause 6.8 do not apply; and
- the data requirements set out in clause 6.9 do not apply.

Further, clause 2.5.2(b) prohibits an NSP from imposing charges under the provisions of chapter 6 for market network services. The remaining elements of chapter 6 of the code that impact on market network services are part G – Ringfencing, and schedules 6.1 – 6.8.

### 10.4.1 Issue for the Commission

Effective network pricing arrangements will provide for appropriate price signals for new investments and will prevent monopoly NSPs making excess profits. Any changes to the network pricing provisions of the code that are not consistent with these goals may significantly diminish the public benefit arising from the operation of the NEM.

### 10.4.2 What the interested parties say

TransEnergie, National Grid and BDB all claim that several clauses in chapter 6 are ambiguous or need clarification. TransEnergie also states that the application of chapter 6 to MNSPs needs to be clarified. In particular TransEnergie, NorthPower (now known as Country Energy) and TransGrid all raise concerns about clause 6.1.4A and its interpretation in the situation where an MNSP wishes to connect to a DNSP rather than a TNSP.

### 10.4.3 What the applicant says

NECA states that there should be adequate ring fencing from any co-owned regulated and non-regulated businesses to ensure that the operation of the regulated business will not be influenced by the possibility of consequential profit or loss of the non-regulated business.

### 10.4.4 Issues arising from the draft determination

In its draft determination the Commission imposed the following conditions of authorisation:

**C10.3 Clause 6.1.4A must be amended as follows:**

**(a) Chapter 6 does not govern the principles or rules for the calculation of prices a market network service provider may charge for its services.**

**(b) Until 31 December 2002, chapter 6 does not govern the principles or rules for the calculation of prices for transmission and distribution services provided by a network service provider to:**

**(1) a market network service provider; or**

**(2) another network service provider for electricity delivered to a market network service provider through the network of the other network service provider (except for any such electricity which is ultimately consumed within the other network service provider's network).**

**(c) Until 31 December 2002, charges for the network services referred to in clause 6.1.4A(b) are governed by the provisions of clause 5.5A only.**

**C10.4 Clause 6.19(a) of the code must be amended to refer to 31 December 1997, the date of effect of the Commission's first authorisation determination in respect of the code.**

### 10.4.5 Commission's considerations

The Commission notes the concerns of the interested parties regarding the ambiguity of some clauses in the proposed arrangements and recommends that NECA review these clauses, and where necessary correct any errors or ambiguities.

Clause 6.1.4 was subject to the interim authorisation granted by the Commission on 25 January 2000. At that time the Commission imposed a condition of authorisation seeking to clarify clause 6.1.4. However, the amendments to clause 6.1.4 were not effective and the condition of authorisation was amended on 23 February 2000. Clause 6.1.4 currently reads:

> 6.1.4 Application of Chapter 6 to Market Network Services
>
> (a) Chapter 6 does not govern the principles or rules for the calculation of prices a *Market Network Service Provider* may charge for its services, nor the charges for *transmission* and *distribution services* provided by a *network service provider* to a *market network service provider*. Charges for *network services* provided to a *market network service provider* are governed by the provisions of clause 5.5A.

However, clause 6.1.4 still does not adequately deal with TUOS charges for embedded MNSPs. Country Energy has strongly argued that the intention of the code is that an MNSP should not be subject to TUOS charges, and by extension, where an MNSP is connected to a DNSP, the DNSP should not be charged TUOS charges for the MNSP's load.

In the case of Directlink, which is connected to Country Energy's distribution network, the clause 6.1.4 clearly provides that Country Energy cannot levy network charges upon Directlink, but does not unambiguously preclude TransGrid and Powerlink from charging Country Energy in respect of flows across Directlink.

The Commission considers that it is appropriate that DNSPs not be charged TUOS charges for electricity delivered to an MNSP through the DNSP (except for any such electricity which is ultimately consumed within the DNSP's area).

The Commission therefore requires that clause 6.1.4 be amended as set out in condition C10.3.

The Commission also proposes to extend the existing interim authorisation to include the amended clause 6.1.4, and to extend the date of expiry of the interim authorisation to cover the period from the date of the final determination to the date the code changes take effect. Section 10.6 of this determination discusses the interim authorisation in greater detail.

*Ring-fencing*

The Commission considers it vital that ringfencing provisions apply to MNSPs, requiring a clear separation between any market and prescribed network services. The Commission notes that the ringfencing provisions in part G, chapter 6 of the code refer to TNSPs and DNSPs, rather than NSPs. The Commission's interpretation of the code is that the definition of a TNSP and DNSP can include an MNSP, in which case the ringfencing provisions of chapter 6 will apply to MNSPs. However, to the extent that there is any ambiguity or any possibility of MNSPs not being subject to the ringfencing guidelines, the Commission will require an amendment to the code to put the issue beyond doubt.

*Other issues*

The Commission notes that clause 6.19(a) deems all existing interconnectors to be regulated at the time of authorisation of the code. This may be considered to apply to market network services in existence at the time of any subsequent authorisations of the code, although such an outcome is clearly unintended. This can be remedied by the inclusion of the date of the first authorisation the code took effect, that is 31 December 1997.

### 10.4.6 Conditions of authorisation

**C10.4 Clause 6.1.4 must be amended as follows:**

**(a) Chapter 6 does not govern the principles or rules for the calculation of prices a market network service provider may charge for its services.**

**(b) Chapter 6 does not govern the principles or rules for the calculation of prices for transmission and distribution services provided by a network service provider to:**

**(1) a market network service provider; or**

**(2) another network service provider for electricity delivered to a market network service provider through the network of the other network service provider (except for any such electricity which is ultimately consumed within the other network service provider's network).**

**(c) Charges for the network services referred to in clause 6.1.4(b) are governed by the provisions of clause 5.5A only.**

**C10.5 The code must be amended to clarify that the ringfencing guidelines apply to MNSPs.**

**C10.6 Clause 6.19(a) of the code must be amended to refer to 31 December 1997, the date of effect of the Commission's first authorisation determination in respect of the code.**

## 10.5 Other amendments - Market rules

NECA has proposed that chapter 3 of the code be amended to take into account the presence of market network services in respect of the following:

- network losses and constraints;
- projected assessment of system adequacy;
- central dispatch and market operations;
- spot price determination;
- ancillary services;
- market intervention;
- market information;
- force majeure;
- settlements; and
- participant compensation fund.

### 10.5.1 Issues for the Commission

The majority of the proposed changes to chapter 3 of the code amend existing provisions to take into account the existence of MNSPs. As such competition concerns regarding these provisions have previously been discussed, for example in the Commission's determinations of 10 December 1997, and 19 August 1999.

Such issues may include the introduction of distortions to the market which may reduce overall public benefits or contracts, arrangements or understandings that may substantially lessen competition in the NEM, in contravention of s.45 of the TPA.

### 10.5.2 What the applicant says

NECA states that the various changes to chapter 3 convey rights and obligations on scheduled NSPs that are analogous to those applying to scheduled generators and market customers with scheduled loads.

### 10.5.3 What the interested parties say

TransEnergie states that clause 3.8.6(a)(f) allows for an unbound margin for error on NEMMCO's part during the transitional period (until 30 June 2000).

TransGrid claims a number of amended clauses in chapter 3 are confusing or may contain errors.

### 10.5.4 Commission's considerations

The Commission notes TransEnergie's concerns regarding unbound margins for error, but notes the transition period will expire prior to those elements of the code taking effect.

The Commission notes TransGrid's concerns but overall considers that the changes to chapter 3 of the code are largely consequential and are necessary to facilitate the introduction of MNSPs and scheduled network services into the NEM. However, the Commission is concerned about the possible introduction of greater uncertainty into the code, and hence recommends that NECA consider the comments provided by TransGrid with a view to amending any clauses where clarification is required.

## 10.6 Other amendments - Power system security

Changes to chapter 4 of the code set out the rights and obligations of MNSPs with respect to system security. There are a number of consequential changes to the provisions of chapter 4, but amendments also include extending NEMMCO's powers of direction to MNSPs, and enabling MNSPs to claim compensation where they comply with NEMMCO's directions.

### 10.6.1 Issue for the Commission

The Commission must consider whether the technical requirements and obligations on code participants as specified in chapter 4 contribute to any anti-competitive detriment arising from the code arrangements without any offsetting public benefits from maintaining a secure and well functioning NEM.

### 10.6.2 What the interested parties say

TransGrid argues it is inequitable that NEMMCO may not require MNSPs to test their black start-up facilities to demonstrate their compliance with local black start-up requirements, although generators may be required to do so.

### 10.6.3 Commission's considerations

The Commission recommends that NECA should review the requirement for testing local black start up facilities and amend the code if it considers any inequity in treatment between MNSPs and other providers of black start up services is material.

Overall the Commission considers that the proposed changes to chapter 4 of the code are required in order to allow the full and safe participation of MNSPs in the NEM. Further the Commission is of the opinion that there is considerable public benefit arising from the arrangements that promote a safe and reliable means of generating and transporting electricity, reduce the risk of system wide disruption and seek to minimise the impacts of any such disruptions.

## 10.7 Other amendments - Metering

The proposed changes to the metering chapter of the code deal with:

- extending the application of chapter 7 to MNSPs;
- clarifying the rights to access metering data based on rights to payments or obligations to pay for energy;
- granting NEMMCO the discretion to require metering facilities at each end of a two terminal link (market network service interconnector); and
- granting NEMMCO the discretion to require check metering facilities at each end of a two terminal link (market network service interconnector).

### 10.7.1 Issue for the Commission

The application of the metering provisions of the code to MNSPs may represent a barrier to entry and as such may diminish the public benefits associated with the introduction of MNSPs to the NEM.

### 10.7.2 Commission's considerations

The Commission considers that detailed metering requirements are essential for the smooth functioning of the NEM, and considers it appropriate that the metering provisions of the code be extended to encompass MNSPs.

## 10.8 Interim authorisation

At the time NECA applied for authorisation of the MNSP code changes, and later the network pricing code changes, NECA also requested the Commission to grant interim authorisation to the code changes required to facilitate the entry of MNSPs into the NEM. On 6 October 1999, the Commission granted interim authorisation to the proposed code changes in chapters 2, 3, 4 and 7 of the code. NECA then requested that the interim authorisation be extended to include certain elements of chapters 5 and 6 of the code, also required to allow MNSPs to participate in the NEM. The Commission granted interim authorisation to certain provisions in chapters 5 and 6 of the code on 25 January 2000.

In response to concerns about the interpretation of the conditions of authorisation, the Commission revoked and regranted the interim authorisation on 23 February 2000. The letters to NECA regarding the interim authorisation are available on the Commission's website at www.accc.gov.au

However, the code changes arising from the interim authorisation process have not been adequate to address the issue of embedded MNSPs. This issue is discussed in section 10.4 above, and the Commission has imposed a condition of authorisation amending clause 6.1.4 of the code.

Further, the interim authorisation is currently expressed to expire at the time the Commission makes its final determination on the applications for authorisation of the network pricing code changes. However, a period of at least 21 days will elapse before the authorisation takes effect, and further time will elapse before the code changes take effect. For this reason the Commission grants interim authorisation to the MNSP code changes until the network pricing code changes take effect, being the date of gazettal of the code changes in the South Australian Government Gazette.

The terms of the interim authorisation are set out in section 11 of this determination.

# 11 Determination

This determination is made on 21 September 2001. The Commission considers that the proposed arrangements and conduct set out in the network pricing and MNSP code changes:

1) are likely to result in a benefit to the public which outweighs the potential detriment from any lessening of competition that would result if the proposed conduct or arrangements were made, or engaged in; and

2) are likely to result in such a benefit to the public that the proposed conduct or arrangements should be allowed to take place or be arrived at.

For reasons outlined in chapters 4-10 of this determination, the Commission proposes, to authorise the amendments to the code contained in application numbers 90704, 90705 and 90706. In its review of these code changes, the Commission has identified a number of provisions that will detract from the public benefit or increase the level of anti-competitive detriment attributable to the implementation of these arrangements. Authorisation is therefore granted subject to the conditions below. The Commission proposes to limit the period of the authorisations to 31 December 2010, except for those code changes that have earlier termination dates.

## Conditions of authorisation

### *4.2 TUOS Usage charge*

**C4.1 The proposed provisions of the code relating to the calculation of customer TUOS usage charges and prices (including clause 6.4.3B and schedule 6.4) must be amended so that:**

**(a) all references to a cost range and selection from within a cost range are removed;**

**(b) a single cost for each connection point is established, instead of a cost range;**

**(c) with the regulator's approval, the modified CRNP method (method 2 of schedule 6.4) may be used to establish the cost at every transmission connection point within the entire area over which the pricing calculation is being undertaken;**

**(d) if the modified CRNP method is not used then the standard CRNP method (method 1 of schedule 6.4) must be used.**

**C4.2 The code must be amended to require NECA, within 18 months of the date of this determination, to complete a review, in accordance with code consultation procedures, which examines whether:**

**(1) closer integration of transmission pricing into the energy market;**

**(2) a modified regime of transmission usage prices; and**

**(3) the removal of the cap on price changes referred to in clause 6.5.5**

**can be expected to improve the efficiency of the NEM, and make recommendations as to what changes (if any) should be made to the code. Any code changes arising from the above review must be brought to the Commission within 3 months of the completion of the review.**

**C4.3 The Code must be amended to ensure the provisions of chapter 6 of the Code unambiguously provide for TUOS usage charges to be recalculated annually. Clause 6.5.5 must be amended to clarify that the cap on the rate of change of prices is to be applied on a year to year basis and remove references to the regulatory control period.**

**C4.4 The proposed deletions to clause 6.3.4 must not be made. The proposed provisions for allocating costs to connection points with other networks must be deleted.**

**C4.5 Clause 6.19(c) must be amended to change the reference to clause 6.4.3C to 6.4.3B.**

**C4.6 Chapter 6 of the code must be amended such that the term price refers to a rate or unit price and the term charge refers to dollar amount.**

### *4.3 TUOS General charge*

**C4.7 Clauses 6.5.4 and 6.4.3C(d) of the code must be amended to specify the following method for calculating the customer TUOS general price to have effect at each relevant transmission connection point during a particular financial year and the way in which it must be applied to compute the customer TUOS general charge to be levied at that connection point during the financial year:**

**(a) The customer TUOS general price to have effect at a connection point during the particular financial year shall take the form of either (i) an energy price ($/MWh) or (ii) a capacity price ($/MW);**

**(b) The applicable price shall be whichever of the above forms results in the lower customer TUOS general charge when applied as described in (d ) and ( f) below, subject to the proviso that the capacity price can only be utilised where the circumstances specified in (e) apply;**

**(c) The energy price shall take the same value throughout the region or regions over which the price calculation is being made and likewise the capacity price;**

**(d) The energy price shall apply to the total metered energy offtake at the connection point during the financial year completed twelve months prior to the start of the financial year for which the price has effect excepting that (i) if the requisite metering data are unavailable or (ii) in the case of a new customer or (iii) with the approval of the regulator,**

**the price shall apply to the total metered energy offtake during the financial year for which the price has effect;**

**(e) The capacity price can only be utilised at a connection point if the customer's connection agreement or other enforceable instrument nominates a fixed maximum demand for that connection point together with substantial penalties for exceeding;**

**(f) The capacity price shall apply to the fixed maximum demand referred to in (e)**

**(g) The customer TUOS general charge to be levied at the connection point during the financial year, or to be rebated if the calculated amount is negative, shall be the dollar amount which results from applying the applicable price, determined in accordance with (b) above, which is to have effect during the financial year. The amount shall be computed as specified in (d) or (f) (whichever is appropriate);**

**(h) The values for the energy price and the capacity price are to be selected so that (i) a customer with median load factor will be substantially indifferent as to which is applied and (ii) the total revenue recovered or rebated through amounts calculated in accordance with (g) will (neglecting the effect of any negotiated price discounts and relying on forecasts of energy usage where necessary) equal the amount determined in accordance with clause 6.4.3C(a).**

**Clause 6.4.3C must be amended to ensure that under or over recovery of revenue through customer TUOS general charges in one financial year is taken into account in setting Customer TUOS general prices in subsequent years.**

**C4.8 Clause 6.3.4C must be amended to provide that any under or over recovery of revenues to be taken into account in calculating the general charge the following year, must be adjusted to reflect the length of time it has been held by or owed to the TNSP. The interest rate to apply in the adjustment must be approved by the relevant regulator.**

**C4.9 The code must be amended to specify that the calculation of customer TUOS general prices is to be repeated annually.**

**C4.10 Clause 6.4.3C(b)(1) must be amended to refer to clause 6.4.8 instead of 6.4.9.**

**C4.11 Clause 6.4.3C(c)(5) must be amended to replace the reference to clause 5.5(f)(3) with a reference to 5.6.2(m).**

**C4.12 All occurrences in the code of 'Customer TUOS fixed charge' must be deleted and replaced by references to the 'Customer TUOS general charge' or 'Customer TUOS general price', as appropriate.**

**C4.13 Clause 6.4.3C(e) must be deleted.**

*4.4 Common service charges*

**C4.14 Clauses 6.4.4 and 6.5.6 of the code must be amended to specify a method for the calculation of common services prices and charges that is similar to that required for customer TUOS general charges in condition 4.7.**

*4.5 Negotiation of price discounts*

**C4.15 The code (including clause 6.5.8) must be amended to require that where a TNSP agrees to a discounted charge the TNSP may only recover the amount of the discount from other network users provided the discount relates to a general charge or a common services charge and the TNSP demonstrates to the ACCC's satisfaction that the discount complies with the ACCC's Guidelines for the Negotiation of Discounted Transmission charges.**

**C4.16 The code must be amended so that the regulator, when setting a revenue cap for a Transmission Network Owner and or Transmission Network Service Provider, must have regard to circumstances where the costs of discounts have been recovered from other network users, despite the discounts not satisfying the ACCC's Guidelines for the Negotiation of Discounted Transmission charges.**

**C4.17 The code must be amended to require TNSPs to seek approval from the Commission for the recovery of the costs of discounts offered prior to the promulgation of the Commission's Guidelines for the Negotiation of Discounted Transmission Charges.**

**C4.18 Proposed clause 6.5.8(d) must be deleted.**

**C4.19 Proposed clause 6.5.8(c) must be deleted from the code.**

**C4.20 Clause 6.5.8 must be amended to replace references to a *Code Participant* with references to a *Network User*.**

**C4.21 Clause 6.1.5(b) must be deleted.**

**C4.22 The code must be amended to require TNSPs to include information on negotiated transmission price discounts in their annual compliance statements to the regulator. The TNSPs' annual compliance statement to regulator must clearly set out the discounts issued to each customer, the amounts to be recovered from remaining customers, and substantiate any claims for confidentiality.**

**The code must be amended to allow the regulator to publish aggregate information on the price discounts offered in accordance with clause 6.5.8 and the proportion of revenue to be recovered from other network users.**

*4.6 Financial transfers between network service providers*

**C4.23 The proposed changes to clause 6.7.4 must be deleted, except for retaining the possibility of transfers arising in the future from the application of a**

**revised version of schedule 6.8, the requirement for NECA to review the inter-regional allocation of general charges and extension of the reference to clause 6.4.3 to include 6.4.3A, B and C.**

**C4.24 Clause 6.7.4 must be amended such that the terms of reference for the review must include:**

**(a) the option of NEM-wide general prices;**

**(b) NEM-wide transfers relating to usage charges to implement a "user pays" approach to the existing transmission network; and**

**(c) the provisions for the distribution and allocation of inter-regional settlement residues;**

**The completion date for the review, the date of commencement of clause 6.7.3 and the date of cessation of clause 3.6.5(a)(5)(ii) must be changed to 1 July 2003.**

*5 Distribution network pricing*

**C5.1 The code must be amended to require DNSPs to allocate TUOS usage charges to distribution users, who have a metering installation that is capable of capturing relevant transmission and distribution system usage data, in a way that preserves the economic signalling of the TUOS usage prices.**

**C5.2 Clause 6.14.6(d) must be deleted.**

**C5.3 Clauses 6.14.6 must be amended to replace the references to *Code Participant* with references to *Network User*.**

*6.1 Development of networks within a region*

**C6.1 Clause 5.6.2 must be amended to ensure that the consultations to be undertaken by a network service provider:**

**(a) are not limited to only those options that satisfy the regulatory test; and**

**(b) must be undertaken even where a generator or MNSP agrees to bear all of the applicable costs of a proposed augmentation.**

*6.2 New investments – beneficiaries pay*

**C6.2 The code must be amended to require NECA, within 12 months of this determination, to complete a review, in accordance with code consultation procedures, of Schedule 6.8 of the code. NECA's review must:**

**(a) identify an effective the methodology for allocating the costs of new investments;**

**(b) identify a default cost allocation to apply in circumstances where the outcomes of the cost allocation determined in accordance with the methodology are disputed; and**

**(c) examine the potential for property rights associated with the cost allocation to be introduced.**

**Within 3 months of the completion of the review NECA must make recommendations regarding code changes to be brought to the Commission for authorisation.**

**C6.3 The code must be amended so that the new beneficiaries pays arrangements can not be implemented until after the revised schedule 6.8 and any associated code changes arising from NECA's review have been inserted into the code.**

*7.1 Prescribed service standards*

**C7.1 The code must be amended to allow the ACCC to set, collect and publish annual performance statistics obtained from TNSPs that relate to the service standards published in accordance with clause 6.5.7(b).**

**C7.2 The code must be amended to allow the jurisdictional regulators to use a form of CPI-X regulation that may take into account prescribed network service standards.**

**C7.3 The code must be amended to allow the ACCC to use a form of CPI-X regulation that may take into account prescribed transmission network service standards.**

*7.2 Negotiable services*

**C7.4 Clauses 6.5.9 and 6.14.7 must be amended to require an NSP to provide all such commercial information, including but not limited to cost information, which a network user may reasonably require in order to engage in effective negotiation with the NSP.**

**C7.5 Clause 6.5.9 must be amended to require each TNSP, within 3 months of gazettal of the network pricing and MNSP code changes, to:**

**(a) develop and publish a draft negotiating framework that conforms with the requirements of the frameworks specified in clause 6.5.9(b);**

**(b) develop a final negotiating framework using the code consultation procedures; and**

**(c) at the conclusion of that consultation, publish the negotiating framework.**

**C7.6 Clause 6.5.9(c)(1) must be deleted and the words 'and subject to any amendments or conditions imposed by the ACCC' in clause 6.5.9(c)(2) must be deleted.**

**C7.7 Clauses 6.5.9(a) and 6.14.7(a) must be amended to specify that they do not apply to MNSPs.**

**C7.8 Clauses 6.5.9 and 6.14.7 must be amended to require network service providers to determine the potential impact on other network users of any negotiated variation in service levels to a network customer. The network service provider must notify and consult with other affected network users and must ensure that a negotiated variation in service level does not infringe the current level of service and the rights other parties have under the code.**

**C7.9 Clause 6.5.8 and 6.14.6 must be amended:**

**(a) to require network service providers to negotiate prescribed services or prescribed distribution services to a lower standard than that specified in the code, where requested by a customer; and**

**(b) to limit any cost reductions offered to the customer to those reflecting the network service providers' avoided costs (if any).**

**C7.10 The code must be amended to require negotiations between an NSP and a network user on the following matters to be conducted in accordance with the negotiating framework developed by the NSP according to clauses 6.5.9 or 6.14.7:**

**(a) any matter negotiable under clauses 5.5 or 5.5A;**

**(b) discounts to the customer TUOS general price or the customer common services price;**

**(c) negotiation of prescribed services or prescribed distribution services to a higher standard than that specified in the code; and**

**(d) negotiation of prescribed services or prescribed distribution services to a lower standard than that specified in the code.**

**Where the matter under negotiation relates to (b) above, the requirement in the negotiating framework to publish outcomes shall be limited to a requirement to publish aggregate information on the total costs of discounts negotiated and the portion of the costs to be recovered from other network users.**

**C7.11 Clauses 6.5.9 and 6.14.7 must be amended to impose similar obligations on the network user to disclose information as those imposed on the network service provider. There should be similar exclusions regarding confidentiality and restrictions on the passing on of information, except that the NSP must have a right to pass on information to the ACCC for the purposes of satisfying the Commission it has complied with discounting guidelines as envisaged under condition 4.15.**

### *7.3 Generator and MNSP access services*

**C7.12 The code must be amended to require NECA, within 12 months of this determination, to review the scope for facilitating firm access to the transmission network through options such as introducing a regime of**

**transmission property rights. The review must be undertaken using the code consultation procedures and be undertaken in conjunction with the reviews specified in conditions C4.2 and C6.2.**

*8.1 Unbundling TUOS usage and general charges*

**C8.1 The code must be amended to require that where TNSPs provide information to transmission customers about transmission network charges, they must separately identify the TUOS usage, TUOS general and common service charge components of charges levied.**

**C8.2 The code must be amended to:**

**(a) allow transmission customers to request and receive information from TNSPs regarding their own TUOS usage charges and the methodology used to calculated them; and**

**(b) specify that in fulfilling a request for information by a network customer, TNSPs are not required to provide commercially sensitive information of a third party.**

*8.2 Unbundling TUOS / DUOS network charges*

**C8.3 The code must be amended to require DNSPs to provide customers, with a load of greater than 10MW or 40GWh per annum or which have metering equipment which is capable of capturing relevant transmission and distribution system usage data, with details of the TUOS usage, general and common service charge components of their network charges, where requested. The code must be amended to require DNSPs to notify customers of the charge for providing this information.**

**The amendments must be on the same basis as specified in clause 6.14.8 and amended by C8.3-8.6.**

**C8.4 Clause 6.14.8(b) must be amended to specify that the charge for providing the TUOS/DUOS disclosure statement must be no greater than the variable costs incurred by the DNSP in preparing the statement.**

**C8.5 Clause 6.14.8(b) must be amended by replacing ‘30 days’ with ‘10 business days’.**

**C8.6 Clause 6.14.8 must be amended to require the DNSPs to provide customers with detailed information on how the network charges and allocations were determined, upon request. This information must be sufficient to allow customers to assess the impact on their network charge resulting from a change in their network use.**

**C8.7 Clause 6.14.8 must be amended so that it takes effect immediately upon gazettal of the network pricing and MNSP code changes.**

*9 Embedded Generation*

**C9.1 The proposed clause 5.5(i) must be replaced with words substantially equivalent to the following:**

**To calculate the amount to be passed through to an *Embedded Generator* in accordance with clause 5.5(h), a *Distribution Network Service Provider* must if *transmission usage prices* were in force at the relevant *transmission connection points* throughout the relevant *financial year*:**

**(a) determine the transmission usage charges that would have been payable by the *Distribution Network Service Provider* for the relevant *financial year* if the *Embedded Generator* had not injected any energy at its *connection point* during that year;**

**(b) determine the amount by which the charges calculated in (1) exceed the transmission usage charges actually payable by the *Distribution Network Service Provider*, which amount will be the relevant amount for the purposes of clause 5.5(h);**

**else the *Distribution Network Service Provider* must apply an equivalent procedure to that component of its transmission charges which is deemed by the relevant *Transmission Network service Provider* to represent the marginal cost of transmission, less an allowance for locational signals present in the spot market.**

**C9.2 The code must be amended to require NECA to review the arrangements for the pass through of avoided TUOS usage charges to embedded generators before the implementation of any new arrangements that allocate network charges to generators.**

*10.2 Registration of MNSPs*

**C10.1 A new proforma access undertaking must be inserted into the code and the code must be amended to require MNSPs to submit the new proforma access undertaking, rather than the access undertaking in schedule 5.8.**

*10.3 Network connection and network charges applicable to MNSPs*

**C10.2 Clause 5.2.3(h) must be amended to revise the deadline to 12 months after the ACCC's authorisation of the network pricing and MNSP code changes take effect; and to require NECA to develop code provisions to address the financial risks to a MNSP that arise as a result of a request for connection to a network which is used for the provision of market network services.**

**C10.3 Clause 5.5A of the code must be amended to require DNSPs to pass through to an MNSP the TUOS savings that arise from the MNSP being connected to the distribution network. The amendments to the code must be based on the provisions for embedded generators in clauses 5.5(h) and (i), as amended by condition C9.1.**

### *10.4 Application of chapter 6 of the code to MNSPs*

**C10.4 Clause 6.1.4 must be amended as follows:**

**(a) Chapter 6 does not govern the principles or rules for the calculation of prices a market network service provider may charge for its services.**

**(b) Chapter 6 does not govern the principles or rules for the calculation of prices for transmission and distribution services provided by a network service provider to:**

**(1) a market network service provider; or**

**(2) another network service provider for electricity delivered to a market network service provider through the network of the other network service provider (except for any such electricity which is ultimately consumed within the other network service provider's network).**

**(c) Charges for the network services referred to in clause 6.1.4(b) are governed by the provisions of clause 5.5A only.**

**C10.5 The code must be amended to clarify that the ringfencing guidelines apply to MNSPs.**

**C10.6 Clause 6.19(a) of the code must be amended to refer to 31 December 1997, the date of effect of the Commission's first authorisation determination in respect of the code.**

## Interim authorisation

Further, pursuant to subsection 91(2) of the Act, the Commission grants interim authorisation to the following clauses of the code:

- MNSP code changes in Chapters 2, 3, 4 and 7 of the code, as identified in applications for authorisation A90704 – A90706, dated 26 July 1999;
- Clauses 5.2.3, 5.3.6, 5.5(e)(2), 5.5A, 5.6.2(a1), 5.6.3, 5.6.6, schedules to chapter 5, 6.1.4(a) (renamed 6.1.4A), and 6.19(d) to (f), with the exception that the interim authorisation does not apply clause 5.5A(g)(2)(A); and
- The following definitions in chapter 10 of the code - annual revenue requirement, black start capability, central dispatch, dispatch, dispatch instruction, dispatch offer, dispatch offer price, financially responsible, generation dispatch offer, independently controllable two-terminal link, inflexible, loading level, market connection point, market network service provider, market network service provider access, market network service, Market Participant, negotiated use of system charges, network dispatch offer, network element, network loop, profile, ramp rate,

registered bid and offer data, reserve contract, scheduled network service, scheduled network service provider, and two-terminal link.

**The interim authorisation is subject to the following condition being met:**

**CI.1 Clause 5.2.3(h) must be amended to revise the deadline to 12 months after the ACCC's authorisation of the network pricing and MNSP code changes take effect; and to require NECA to develop code provisions to address the financial risks to a MNSP that arise as a result of a request for connection to a network which is used for the provision of market network services.**

**CI.2 Clause 5.5A of the code must be amended to require DNSPs to pass through to an MNSP the TUOS savings that arise from the MNSP being connected to the distribution network. The amendments to the code must be based on the provisions for embedded generators in clauses 5.5(h) and (i).**

**CI.3 Clause 6.1.4 must be amended as follows:**

**(a) Chapter 6 does not govern the principles or rules for the calculation of prices a market network service provider may charge for its services.**

**(b) Chapter 6 does not govern the principles or rules for the calculation of prices for transmission and distribution services provided by a network service provider to:**

**(1) a market network service provider; or**

**(2) another network service provider for electricity delivered to a market network service provider through the network of the other network service provider (except for any such electricity which is ultimately consumed within the other network service provider's network).**

**(c) Charges for the network services referred to in clause 6.1.4A(b) are governed by the provisions of clause 5.5A only.**

# Appendix A - Submissions

Australian Cogeneration Association (now Australian EcoGeneration Association) (plus 1 supplementary submission)

Australian Conservation Foundation

Australian Inland Energy

Australian Greenhouse Office

Bardak Energy Services

Basslink Development Board

Business Council of Australia Energy Reform Taskforce

ElectraNet SA

EnergyAustralia

Electricity Markets Research Institute

Ergon Energy

Gallaugher and Associates Proprietary Limited

GPU PowerNet (now SPI PowerNet) (plus 1 supplementary submission)

Institute of Public Affairs Limited

National Generator Forum (plus 2 supplementary submissions)

National Grid International Limited

New South Wales Treasury Market Implementation Group

Powercor

Powerlink Queensland

Queensland Alumina Limited

Several Victorian Distribution Businesses - Citipower, Eastern Energy (now TXU Australia), Powercor and United Energy

South Australian Department of Treasury and Finance

Stanwell Corporation Limited

TransEnergie Australia Proprietary Limited (plus 1 supplementary submission)

TransGrid (plus 1 supplementary submission)

Transend Networks Proprietary Limited

Victorian Energy Networks Corporation

***Submissions arising from the draft determination***

Australian EcoGeneration Association

Australian Greenhouse Office

Basslink Proprietary Limited

Delta Electricity

ENERGEX Limited

Enertrade

Ergon Energy

Electricity Supply Association of Australia

Hazelwood Power

Hydro Tasmania

InterGen

Loy Yang Power

National Electricity Distributors Forum - ActewAGL, Advance Energy, AGL Electricity, Aurora Energy, Australian Inland Energy, CitiPower, ENERGEX, EnergyAustralia, Ergon Energy, ETSA Utilities, Great Southern Energy, Integral Energy, NorthPower (now known as Country Energy), Powercor, TXU, United Energy and Western Power.

National Electricity Market Management Corporation

National Generator Forum

NRG Flinders

New South Wales Treasury Market Implementation Group

Origin Energy

Powerlink Queensland

Queensland Treasury

Several Victorian Distribution Businesses - AGL Electricity, Citipower, Powercor, TXU Australia and United Energy

South Australian Department of Treasury and Finance

Snowy Hydro Trading Proprietary Limited

Stanwell Corporation Limited

Tarong Energy

Tasmanian Department of Treasury and Finance

TransEnergie Australia Proprietary Limited

TransGrid

VAW Kurri Kurri Proprietary Limited

Victorian Energy Networks Corporation

Western Power

# Appendix B - Overview of existing and proposed transmission pricing arrangements

## B.1 Existing transmission pricing methodology

The code currently defines a number of transmission services on which networks can levy charges, namely entry, exit, common, use of system and generator access services.

***1. Entry services — provided to generators at a single connection point***

A generator's connection service charges may be specifically allocated in a contract and if not, a generator's entry service charges are recovered by:

- allocating amongst all the generators at a particular connection point, the revenue needed to cover the entry assets at that connection point (plus an equitable amount for assets that jointly provide entry and exit services); and
- recovering this revenue through a fixed annual charge.

***2. Exit services — provided to transmission network customers at a single connection point***

A customer's connection service charges may be specifically allocated in a contract and if not, a customer's exit service charges are recovered by:

- allocating amongst all the customers at a particular connection point, the revenue needed to cover the exit assets at that connection point (plus an equitable amount for assets which jointly provide exit and entry services); and
- recovering this revenue through a fixed annual charge.

***3. Transmission use of system (TUOS) services — provided to either generators or customers***

- Revenue arising through inter-regional settlements residues and settlements residue auctions (unless otherwise allocated under chapter 9 of the code) is subtracted from the amounts to be recovered through TUOS charges.
- Fifty per cent of the remaining TUOS service costs are allocated to customer connection points using the CRNP method.
  - The variable price is determined at the discretion of the TNSP but must reflect the investment conditions in the network and may include any combination of demand, energy and fixed charges.
  - The charge may relate to either the actual (metered) use or an agreed use.
  - The demand-based charge is to be calculated on a customer's maximum demand as averaged over a metered half-hour period.
- In a connection agreement, generators may consent to pay some of the TUOS costs.

- Any remaining anticipated revenue shortfall is allocated to customer connection points on a postage stamp basis and recovered from customers through a variable common service charge (the annual rate is the common service cost divided by the network energy delivered).

***4. Common services —provided to customers***

- All of the revenue needed to provide such services is recovered from customers on a postage stamp basis.

- The revenue is recovered through a variable common service charge (the annual rate is the common service cost divided by the network energy delivered).

***5. Generator access services***

This is the risk premium for generators with connection agreements that include firm access compensation arrangements where the revenue is recovered from each generator in accordance with the connection agreement.

## B.2 Proposed changes

The pricing arrangements for entry, exit and common services largely remain unchanged. On the basis of the proposed code changes, generator access services would be removed as one of the classes of transmission services that make up the TNSP's aggregate annual revenue requirement (AARR) (ie. clause 6.3.1(a)(5) of the code is deleted). Nevertheless, it remains as a service that a TNSP can negotiate to provide to a generator or an MNSP (clause 6.4.5). Provision of the service is on the basis of the TNSP's reasonably incurred costs in order to establish compensation arrangements for constraining-off or constraining-on other generators (clause 5.5(f)(4)-(6)).

The main changes to network pricing relate to the TUOS charges and are summarised below.

**A. Generator use of system service costs**

*Negotiated use of system service*

- A generator may agree to pay the TNSP for a proportion of the costs for augmentations of, and extensions to, the transmission network (this service and revenue is distinct from a generator access service).

- These costs can be recovered through a variable price that may include a combination of a demand, energy and/or fixed charge.

*New transmission network investment*

- Large investments

  – As part of the investment appraisal process, TNSPs are to estimate benefits to all network users.

- The relative benefits received by generators and other users determine the proportion of capital costs they will pay.

▪ Small investments

  - As part of their planning processes for new investments, TNSPs must determine the ratio of benefits to generators, distributors and other transmission networks on a class basis.

  - Based on this ratio of benefits, TNSPs can recover the investment costs from the generators in its region.

  - The charges are allocated to individual generators on a pro-rata capacity basis.

**B. MNSP use of system service costs**

*Negotiated use of system service*

TNSPs and MNSPs are required to negotiate in good faith and reach agreement as appropriate on:

▪ connection service charges to be paid by the MNSP;

▪ use of system service charges to be paid;

  - to the MNSP in respect to reductions in the long run marginal cost of augmenting the network as a result of it being connected to the network; and

  - by the MNSP in relation to augmentations or extensions required to be undertaken in respect of all affected transmission and distribution networks.

▪ amounts to be paid by the MNSP in relation to providing MNSP access;

▪ compensation to be provided to the MNSP by the TNSP in the event that MNSP access is not provided; and

▪ compensation to be provided by the MNSP in the event that its dispatch causes generating units or another market network service to be constrained.

**C. Customer use of system services**

*Usage charge*

▪ For non-interconnector connection points, TNSPs allocate to each point a cost that reflects likely future usage from within a range bounded by:

  - CRNP with the cost of each transmission element represented as 50 per cent of its full cost;

  - a modified CRNP approach where the TNSP scales the cost of each transmission element to reflect its use and therefore, indirectly, the future costs of augmentation; and

– a direct assessment of the LRMC determined from the TNSP’s future investment plans and the anticipated load growth and generation development.

- This cost is to be recovered via a variable charge (may include a combination of a demand, energy and/or fixed charge but is subject to a cap of two per cent per annum on any increase over the regional average.

- For a regulated interconnector this usage component (plus a common service charge) will be recovered by a fixed charge, but not prior to NECA completing a review by 1 January 2001.

*General charge*

- This is the residual charge calculated as the TNSP’s AARR:

| | | | |
|---|---|---|---|
| *less* | generator TUOS | | |
| *less* | customer TUOS usage | | |
| *less* | common service | | |
| *less* | settlements residue | | |
| *less* | financial transfer from other TNSPs | *plus* | financial transfers to other TNSPs |
| *less* | excess revenue from previous period due to forecast error | *plus* | revenue shortfall from previous period due to forecast error |
| *less* | negotiated use of system charges from MNSPs | *plus* | revenue shortfall due to 2 per cent cap on customer TUOS charge |
| | | *plus* | payments to market MNSPs and generators for network savings |

- This residual amount is allocated to customer (not MSNP) connection points on a postage stamp basis and recovered through a fixed charge.

# Appendix C - Property rights discussion

This discussion was prepared by Dr Robert Outhred.

*Benefits of property rights*

Well developed network property rights have the potential to improve market efficiency in the following ways:

- *Reduced opportunities to free-ride.* The assignment of appropriate property rights can help overcome the barrier to voluntary network investment that arises due to a perception that others may free-ride on the benefits of the investment, as is conceivable in a shared network.

- *Exposure to externalities.* The assignment of appropriate property rights can help ensure that the impact of one party's utilisation and investment decisions on other users of the shared network are duly considered.

- *Reduced need for regulatory intervention.* To the extent that property rights enable network services to be priced and allocated through the market, there will be less need for a regulated approach to network pricing and investment, with its reliance on the central estimation of benefits and costs.

*Desirable attributes of a property rights system*

To achieve these benefits, the property rights should satisfy criteria such as the following:

- *Clarity.* To be effective, a property right must be enforceable. To be enforceable, the right will need to be clearly and unambiguously defined.

- *Relevance.* The property rights should be effective in the required context, eg the management of network-related trading risks or the protection of investment benefits from free-riders. For example, they will need to be sufficiently comprehensive to prevent free-riding and they will need to be sufficiently focussed to avoid impacts on third parties.

- *Appropriate issuance.* The issuing party needs to be well placed to manage the risks incurred and should be subject to appropriate incentives to act in an even-handed manner.

- *Tradeability.* Ideally, the property rights should be tradeable in a market that is well informed and has no entry or exit barriers. At a minimum, there should be an even-handed negotiating framework within which all impacted parties are represented.

*Assessment of the code's arrangements against these criteria*

The code (including the proposed changes) provides for generators and MNSPs to negotiate intra-regional compensation rights but is silent on how the compensation should be assessed and underwritten. At the inter-regional level, constraints are priced in the spot market, providing a sound basis for defining compensation rights, while settlement residues can underwrite the payments.  By contrast, intra-regional constraints are not priced in the spot market and as a result, there is no clear basis for pricing and underwriting compensation.  Thus it is not clear that compensation arrangements set up under clauses 5.5 and 5.5A can be clear and readily enforceable.

Clauses 5.5(f)(2) and 5.5A(g)(2) make provision for a generator or MNSP to elect to pay for enhancements to the shared network, although it is doubtful that many would do so voluntarily without some assurance that their competitors could not free-ride on the investment.  It is not clear that a clause 5.5 or 5.5A compensation agreement could adequately protect an investor from this externality.

The party issuing the property rights is the NSP who is required to process a connection enquiry or make an offer to connect.  It is not clear that this NSP will be well placed to manage the risks incurred by becoming party to an access agreement.  As already noted, there is no settlement residue cash stream to underwrite risks.  Hence, the NSP will be left with risks which it is not well placed to manage unless it can get agreement from all relevant generators (and/ or MNSPs) to pay compensation in the event that their activities cause others to be constrained.  This may not be feasible.

Also, constraints can originate from sources outside an NSP’s area.  There is no provision in the code for an NSP to negotiate access compensation arrangements with other NSPs that could assist it to manage that risk.

An NSP is required to negotiate ‘in good faith’ but, given its monopoly position, it is not clear that this will impart sufficient incentive to achieve even-handed outcomes.

Thus the present arrangements are not very satisfactory in terms of the issuance criterion.

Access agreements negotiated under clauses 5.5 and 5.5A are not necessarily transferable.  The NSP is required to negotiate to establish agreements, but there is no clear obligation to negotiate relinquishment or variation.  Only generators and MNSPs are permitted to seek to establish access agreements.  This might be contrasted with the inter-regional access provisions, which involve regular open auctions of instruments that are of a reasonable form to support secondary trading.

The present arrangements for intra-regional access therefore appear less than optimal in terms of the tradeability criterion.

Thus the present arrangements are less than ideal in terms of all the criteria identified earlier: clarity, relevance, issuance and tradeability and there must therefore be significant doubt as to their effectiveness.

# Appendix D - Potential refinements to CRNP pricing methodology

The code changes proposed three methods for usage pricing. As discussed in section 4.2 of this determination, having three pricing methods leads to arbitrariness and complexity. There would be benefits in having only one method, providing it delivered appropriate prices in most situations. The modified CRNP method appeared the best of the three specified in the code changes but nevertheless has substantial problems. This appendix outlines some refinements to the modified CRNP method that might be considered if that method was to be proposed as the default transmission pricing technique.

The modified CRNP method, like other CRNP-based methods, can be criticised on the basis that there is arbitrariness in the choice of operating conditions to be analysed and in the derivation of usage prices from the allocated costs. The arbitrariness in the choice of operating conditions could be removed by requiring every half hour in the latest financial year to be utilised. The arbitrariness in the pricing might be eliminated by requiring the prices to be in the form of time-of-use $/MWh values. Time-of-use categories could for example be on-peak, shoulder and off-peak hours in each season. The price applying for each time-of-use category would be derived by dividing the costs allocated to a connection point for all half hours in the relevant category by the consumption during the same period. This would be a transparent and objective way of deriving the final usage prices and would facilitate pass-through of the signals to distribution-connected participants. It could be argued that time-of-use prices do not tightly focus the price signals on periods of network congestion but, as discussed elsewhere, such short-run signals are likely to be best addressed through increased locational pricing in the spot market.

Another drawback relates to over-signalling. The existing code requires inter-regional settlements residues to be deducted from the revenue requirements of relevant assets before allocating costs using CRNP, ensuring that to some extent at least the TUOS charges take account of signals provided through the energy market. Under the applicant's proposed changes, the adjustment for settlement residues would affect the general charges but not the usage charges, resulting in an increased risk of over-signalling. The existing approach is preferable.

Another issue relates to the achievement of consistent price signals across the market. Unless price signals are set consistently, participants in some areas may be inefficiently and inequitably disadvantaged. As a result, benefits of trade will be foregone. The existing code recognises this to the extent of allowing cost allocations to be performed over multiple regions. The code changes envisaged that allocations would normally be performed by each TNSP individually but allowed for financial transfers between NSPs. However inter-regional transfers appeared in the general charge, rather than the usage charge, thus preventing price signals from being propagated inter-regionally.

The simplest and most transparent way to remedy this would be to require a single body to compute all usage prices consistently on the basis of data submitted by the TNSPs. The body would need to be impartial, be competent to undertake the required calculations, be able to do so cost-effectively and be able to be made accountable under the code.  In its draft determination, the Commission proposed that NEMMCO take on the role, but as a submission from TransGrid commented, the IRPC or a coordinating committee of TNSPs could also be considered.

A further problem relates to the timeliness of the price signals. The proposed code changes are unclear about the timing of updating the transmission usage prices, with different clauses suggesting annual or five-yearly updates.  It is desirable for the usage prices to be updated annually so as to ensure the price signals do not attract an overly-large response, as could happen if price signals were maintained rigidly for five years regardless of what response had already occurred.

However some participants will need stability in prices.  Those who require longer-term cash-flow certainty should have the option of a usage price schedule that would be fixed for up to five years.  A schedule would apply to a nominated offtake profile at a nominated location.  The schedule would be based on projected annual prices, computed on the basis of load flow forecasts that took into account the nominated offtake profiles.  As discussed above, it would seem desirable for a single body to compute transmission usage prices for the entire market. That body could also compute the projected annual prices on the basis of load-flow and cost projections supplied by the TNSPs.

This would not expose TNSPs to revenue fluctuations, assuming the role of the general charges continued to be to recover the balance of revenue after taking all revenue from usage charges into account.  In its response to the draft determination, TransGrid noted that the Commission's proposal for universal usage pricing would enable participants to mutually hedge their price risks, as in the energy market, thus removing the need for TNSPs to offer five-year fixed prices.  However, as discussed in section 4.2 of this determination, the Commission has decided not to proceed with the requirement for a universal usage pricing scheme at this time.

Clause 6.5.5 of the code imposes a two percent cap on the annual change in transmission prices at any connection point relative to the region average.  This promotes price stability but, as Powerlink and the ACA argue, it can interfere with efficient pricing.  Its price stabilising role would become redundant if network users had an option of pre-determined five-year price schedules, or had some other means of hedging variations in the annual usage prices.  There would then be little justification for retaining the cap.

CRNP methods allocate costs on the basis of incremental load flows in the network. The question therefore arises as to whether links that provide market network services should be included in the analysis.  Broadly, inclusion would have the effect of exposing network users downstream of market links to some of the costs of upstream regulated assets.  However an MNSP is already exposed to upstream asset costs to some extent through negotiated use of system charges determined in accordance with clause 5.5A.  The MNSP is likely to reflect these costs in its offer prices, thus exposing downstream customers to them via the energy price.  Hence it could be distortionary to expose downstream customers to increased transmission usage charges as well.  On balance, it may be preferable to exclude market network links from the incremental load flow analysis[26] and instead rely on MNSPs passing through the transmission cost signals to which they are exposed.

In summary, consideration could be given to refining the modified CRNP technique as follows:

1. Apply the analysis annually to the entire NEM transmission network

2. Structure the resultant transmission usage prices at each connection point as time-of-use energy prices for peak, shoulder and off-peak hours in each season.

3. Consider operating conditions in every half-hour of the most recent calendar year.

4. For each half hour, determine the number of dollars to be allocated for each asset by (i) dividing the annual requirement by the number of half hours per year, (ii) adjusting for asset utilisation in the half hour concerned and (iii) subtracting revenue attributable to the asset in that half hour, eg from settlement residues or negotiated use of system charges.

5. Determine the price for each connection point for each time-of-use category by dividing the total costs allocated to the connection point in all half-hours falling into the time-of-use category by the total metered offtake during the same period.

6. Treat links dedicated to the provision of market network services as having infinite impedance for the purpose of applying the modified CRNP technique.

The above changes would help ensure the modified CRNP method produced effective price signals in most instances. Other changes discussed in appendix C to the draft determination might also be considered.

[26] Technically, this would mean treating them as having infinite impedance.