Decision
Application for acceptance
National Electricity Market Access Code
16 September 1998

Preface

Under Part IIIA, section 44ZZAA(3), of the *Trade Practices Act 1974* (TPA) the Commission accepts as an access code chapters 1, 2, 4, 5, 6, 7, 8, 9 and 10 of version 2.3 of the National Electricity Code as submitted to the Commission on 28 August 1998. This access code decision deals with the access regime to the electricity transmission and distribution networks that form the national grid in southern and eastern Australia for the services of conveying or controlling electricity.

This decision has been made on the basis that the access code forms an integral part of the reform of the electricity supply industry which has the potential to deliver significant benefits to diverse sectors of the Australian community. The Commission also considers that the NEM access code provides an acceptable balance of the legitimate business interests of network owners, access seekers and the broader public.

This decision follows a determination, on 10 December 1997, by the Commission to conditionally authorise the NEM code. The effect of that decision was that the NEM code would not be authorised, under Part VII of the *Trade Practices Act 1974* (TPA), until certain conditions were met and would be subject to review under subsection 91(4) of the TPA if other conditions were not fulfilled in the future.

While the National Electricity Code is a single document and many of the issues are closely related, the Commission was required to assess the access code and authorisation applications against separate criteria and to make separate decisions. The authorisation determination provides immunity from court action for specified market arrangements or conduct which would otherwise be in breach of Part IV of the TPA. The access code decision provides a mechanism for a single access regime to apply across the transmission networks in the national grid and across the distribution networks in each of the participating states and territory.

The lengthy delay between the earlier authorisation determination and this access code acceptance decision was due to the requirement that the applicant make certain code changes and to agree that certain other issues be reviewed. Unlike the authorisation determination, the Commission's acceptance of the access code is not conditional. This decision is a final decision based on a revised version of the code.

This revised version of the code has addressed many of the Commission's earlier concerns as outlined in its access code draft decision. For example, the code has been revised: to give the regulators the power to develop ring-fencing arrangements and to release otherwise confidential information; to clarify certain rights of connection applicants; and to limit non-uniform transitional arrangements until the end of 2002.

The transmission and distribution networks are now able to submit applications to the Commission for access undertakings under section 44ZZA(1). The Commission's acceptance of complying undertakings would protect the networks from a declaration recommendation (for the services of conveying or controlling electricity) under section 44F(1) of the TPA and would allow the networks to register with NEMMCO and thereby to participate in the national electricity market.

Contents

Glossary

ABARE	Australian Bureau of Agricultural Economics
ACA	Australian Cogeneration Association
BCA	Business Council of Australia
BIE	Bureau of Industry Economics
COAG	Council of Australian Governments
CRNP	Cost Reflective Network Pricing
CSO	Community Service Obligation
CT	Current Transformer
DBs	Distribution Businesses
DMS	Dispute Management System
DRP	Dispute Resolution Process
DUOS	Distribution Use of System
EI Act	*Electricity Industry Act 1993,* Victoria
ESI	Electricity Supply Industry
EUG	Energy Users Group
GBE	Government Business Enterprise
GWh	Gigawatt hour
IC	Industry Commission
IPART	Independent Pricing and Regulatory Tribunal, NSW
IPART Act	*Independent Pricing and Regulatory Tribunal Act 1992,* NSW
IRPC	Inter–Regional Planning Committee
MW	Megawatt
MWh	Megawatt hour
NCC	National Competition Council
NEC	National Electricity Code
NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market
NEM1	National Electricity Market Stage 1
NEMMCO	National Electricity Market Management Company
NFF	National Farmers Federation
NGMC	National Grid Management Council
NSP	Network Service Provider
ORG	Office of the Regulator General, Victoria
ORG Act	*Office of the Regulator General Act 1994* (Victoria)
PNV	PowerNet Victoria
SEQEB	South East Queensland Electricity Board
SMHEA	Snowy Mountains Hydro–Electric Authority
TPA	*Trade Practices Act 1974*

TUOS	Transmission Use of System
VPX	Victorian Power Exchange
VT	Voltage Transformer
WACC	Weighted Average Cost of Capital
WPC	Western Power Corporation

Overview of the NEM access code

Australian governments have initiated fundamental reforms to improve the performance of the electricity supply industry. To varying degrees, the state and territory governments have restructured, corporatised and privatised the previously vertically integrated public monopolies. In a process coordinated through COAG, the relevant jurisdictions have also moved to create the National Electricity Market (NEM) in southern and eastern Australia. The NEM will establish a single wholesale market for electricity and an access regime for the transmission and distribution networks. The arrangements have a national flavour to the extent that the state and territory governments have cooperated in developing and legislating the National Electricity Code (NEC) and the National Electricity Law which together establish the processes and institutions to administer the NEM. Nevertheless, code derogations ensure that some jurisdictional based arrangements will continue, either over a transitional period or indefinitely. The jurisdictional governments will also retain responsibility for environmental issues and electricity regulation more generally.

However, these arrangements must also comply with Commonwealth law. As a result, NECA and NEMMCO applied for, and have received from the Commission, an authorisation of the NEC. These reforms have also fallen into line with the more wide ranging competition policy reforms which, amongst other things, have created the right for third parties to gain access to the services of a facility which is uneconomic to duplicate and is nationally significant (eg electricity transmission networks). Consequently, the jurisdictions via NECA have submitted the relevant sections of the NEC to the Commission for acceptance as an access code under Part IIIA of the *Trade Practices Act 1974* (TPA). The Commission received a draft application to accept an access code from NECA on 15 November 1996 while a formal application was received on 28 April 1997. The Commission published a draft decision on 29 August 1997.

The NEM access code

The NEC is a single document which sets out the operational rules for the NEM. The NEC comprises two distinct but inter-related elements: first, the wholesale electricity market rules; and second, the access arrangements to the transmission and distribution systems.

The market arrangements govern the operation of the electricity wholesale spot market and includes rules for: bidding processes by generators; determining the wholesale prices; central dispatch; settlement; prudential requirements; market information; inter-regional hedging; ancillary services; and market intervention by NEMMCO. These arrangements are not the subject of the access code but they were examined by the Commission as part of its authorisation of the NEM code.

In contrast to the arrangements governing electricity generation and its wholesale and retail sale, the access arrangements are the rules governing connection to and use of the physical wires infrastructure for the transport of electricity. The NEM access code (see Box 1 for more detail) can be characterised as a flexible set of arrangements covering the diverse matters relating to electricity connection and pricing while being broad enough to encompass all of a network's customers (eg generators, users and retailers). This flexibility is necessary as, to a greater or lesser extent, every connection to an electricity network will impact on the performance of that network and therefore on other connected customers.

Box 1: Summary of the National Electricity Market access code

The access code describes arrangements through which generators will physically deliver electricity into the market and allows customers to avoid retailers by separately purchasing wholesale electricity and its transport on transmission and distribution networks. To the extent that the access code has not been designed to govern retail competition, it is likely to be largely irrelevant for the majority of consumers (ie households) who purchase the bundled supply of electricity through retailers.

The NEM access code is principally comprised of chapters 4 to 9 of the NEC but it also encompasses the relevant parts of the remaining NEC chapters as well as the applicable regulatory instruments of the participating jurisdictions. Reflecting the need for flexibility, NECA has proposed an access code which specifies in some detail:

- the framework for achieving and maintaining a secure power system;
- the framework for generators and users to connect to an electricity transmission or distribution network, including;
  - ⇒ a requirement to negotiate and sign a detailed connection agreement;
  - ⇒ agreeing on connection equipment design and technical standards;
  - ⇒ the inspection, testing and commissioning requirements for connected equipment; and
  - ⇒ disconnection procedures;
- investments in networks (ie augmentation) are governed either by:
  - ⇒ commercial arrangements, in the case of new or upgraded connections; or
  - ⇒ administrative planning processes, in the case of a general increase in demand either within a network or across a range of networks;
- the pricing regulatory arrangements to be followed by:
  - ⇒ the ACCC in setting a revenue cap for transmission network service providers; and
  - ⇒ the state and territory regulators in setting a revenue and/or price cap for distribution network service providers;
- the dispute resolution and enforcement mechanisms consisting of administratively created arbitrators, panels and tribunal, backed-up by the relevant courts in each jurisdiction and based on the National Electricity Law (which is to be enacted in each of the participating jurisdictions); and
- separate transitional arrangements for each of the participating jurisdictions.

While the access code generally stipulates obligations and processes, it also stipulates detailed outcomes in terms of technical standards and requirements to preserve system security. The access code envisages that the detailed terms and conditions for access will be determined on a case-by-case basis and included in a connection agreement between the network service provider and the access seeker.

In order to protect their facilities from the possibility of declaration under Part IIIA, an industry access code still requires individual facility owners to submit access undertakings. However, the access code avoids unnecessary duplication by allowing the Commission to waiver the requirement to perform separate public assessments of individual access undertakings.

Statutory assessment criteria

Part IIIA of the TPA allows an industry body to submit an access code for network industries which will consistently apply across all facility owners. The Commission's assessment of the access code is based on statutory requirements which allow the Commission to accept an access code, while having regard to the legitimate business interests of facility owners, the interests of access seekers and the public interest (including its impact on competition, the competitiveness of Australian businesses, the environment, social welfare, regional development and occupational health and safety). The Commission is also allowed to have regard to any other matters it thinks are relevant.

In assessing the access code, the Commission has had to interpret these broad criteria. Consequently, in terms of the legitimate business interests of the network service providers, the Commission expects that the electricity access code should allow network service providers to earn a commercial rate of return. However, to be in the interests of the access seekers and the public, the access code must prevent network service providers from earning monopoly rents. The access code should also allow efficiency improvements in the networks and other parts of the electricity supply industry to be passed on to network users and the wider community.

The Commission believes that it will be in the interests of all parties involved for the access code to include connection and compliance monitoring procedures which maintain the integrity of networks — especially since a poorly performing network can have serious ramifications for the health, safety and property of all parties connected to the grid and on the ability of the system to deliver network services. It will be in the interests of both the network service providers and access seekers for connection procedures to be both streamlined and transparent. Moreover, from the perspective of access seekers and the wider community, connection procedures should not unnecessarily create additional entry barriers for new generators, new customers and/or new technologies.

As the proposed duration of the access code is well into the next century, the access code should be able to cope with the dynamic changes in the market — eg the investment response to a growing demand to use network facilities and a code change process responsive to identified deficiencies.

The Commission's assessment of the NEM access code

Many of the electricity reforms follow what has been done overseas and are seen by the industry, governments and users as an integral part of any package to make the users of the Australian electricity supply industry internationally competitive. Estimates indicate that the benefits of electricity reform are likely to be substantial — eg an increase in GDP by up to $5.5 billion per annum (IC 1995). However, this work does not indicate the extent to which each of corporatisation, industry restructuring or the NEM contribute to the benefits. Nevertheless, an effective access regime for the transmission and distribution networks will generate significant benefits, complement the other reforms and will have a large bearing on whether the benefits of reform are passed on to users and the community.

In support of their application, NECA highlighted the extensive public consultations and scrutiny which accompanied the code's development between 1991 and 1996. For instance, the proposed arrangements have drawn on experience gained from overseas and state markets. The proposed arrangements have been developed in concert with COAG and have been endorsed by the participating jurisdictional governments. Moreover, various interest groups have been involved in developing the code and in the public assessment processes associated with the Commission's authorisation and access code decisions. NECA also provided an application outlining how key features of the code meets the Commission's statutory guidelines for accepting an access code.

Despite the potentially large benefits of an access regime, the Commission's public consultation process revealed that important infrastructure providers, user groups and other interested parties would only provide, at best, conditional support for the access code that was originally submitted to the Commission. In general, participants were supportive of the NEM which includes both a wholesale market and an access regime. Participants were also supportive of the broad approach and principles which will guide pricing, connection and augmentation of electricity networks in the NEM.

However, participants argued that there were a large number of deficiencies hidden in the detail of the code. That the NEM access code is regarded as imperfect is not entirely unexpected as the access code is a first attempt to create a uniform and transparent access regime for electricity networks in southern and eastern Australia. It is also a first attempt at uniformly codifying a range of engineering standards and practices from a variety of sources and network operators. Moreover, the interests of network owners and network users are often competing and it is unlikely there could ever be a consensus on the detail of the NEM access code.

Some of the problems with the code are trivial (eg typographical errors), some of which have already been addressed by code amendments. A large number of problems, identified by participants and in the Commission's draft decision, detract from the code, emphasise the interests of certain parties at the expense of others and reduce the likelihood that the full benefits of electricity reform will be realised. In addition, it could be expected that further problems will emerge once the code arrangements and the NEM is fully functioning. Nevertheless, the Commission believes that these deficiencies can be easily handled through the code change processes and are not significant enough to delay the introduction of the NEM.

However the Commission's draft decision, identified a number of deficiencies in the access code which significantly impact on the interests of access seekers and the public. Prior to making its final decision, the Commission has sought to resolve these issues with NECA and the jurisdictions. In general, the Commission's concerns related to specific code provisions which fell short of the objectives of Part IIIA of the TPA and of the stated principles contained in the NEC itself. In particular, the Commission's major concerns related to:

- establishing a better balance between regulatory flexibility and price certainty by requiring jurisdictional regulators to be independent bodies;
- improving the location incentives of transmission use of system charges by including an avoided costs test for embedded generators and by further examining the efficiency of transmission pricing in the NECA review;
- providing regulators with effective powers to impose ring-fencing arrangements, to acquire and publicly release network information and to make revenue cap determinations on the basis of known service standards;

- negotiation arrangements for network connection (ie clarify rights for access seekers to by-pass networks and to utilise the code's dispute resolution mechanisms); and
- non-uniform jurisdictional arrangements which persist beyond the year 2000.

These concerns have been resolved in a number of ways. First, non-uniform transitional arrangements have largely been restricted to the transitional period up until the end of 2002. Second, the code has been changed to give the regulators powers to develop ring-fencing arrangements, to release otherwise confidential network information (provided it is in the public interest) and to align the powers of the distribution regulators with those of the transmission regulator. Code changes have also clarified rights for network connection applicants (access seekers) to by-pass existing networks, if necessary, and to use the code's dispute resolution arrangements. Third, certain of the code's network pricing arrangements and powers of the regulator (eg in relation to network standards) are the subject of a current review by NECA. In addition, NECA has committed itself to undertake a series of reviews to address the broad range of the Commission's other, but somewhat less critical, concerns — some of these concerns are also the subject of the conditions the Commission attached to its authorisation of the NEC.

However, the issue of the independence of the network pricing regulators has not been resolved to the Commission's complete satisfaction as the applicant and the jurisdictions refused to make independence a code requirement. Nevertheless, the majority of the participating jurisdictions have already established independent regulators for electricity network pricing. Moreover, the South Australian Government has stated that it will be introducing legislation for the introduction of an independent jurisdictional electricity economic regulator within that state.

On the basis of the applicant's response to the access code draft decision, the Commission has accepted as an access code chapters 1, 2, 4, 5, 6, 7, 8, 9 and 10 of version 2.3 of the National Electricity Code as submitted to the Commission on 28 August 1998. This decision has been made on the basis that the access code forms an integral part of the reform of the electricity supply industry in southern and eastern Australia. These reforms have already delivered significant benefits to network users and the broader Australian community. Continuing reforms promise the delivery of further benefits.

In addition, the Commission considers that the NEM access code provides an acceptable balance of the legitimate business interests of network owners, access seekers and the broader public. For instance:

1. The code acts to protect the interests of network users and the public by depriving network service providers of the capacity to unilaterally exploit monopoly power by establishing a price regime to be administered by government regulators. The regulators will have the ability to determine revenue and/or price caps, to enforce accounting and functional ring-fencing arrangements and to publish network information when it is deemed to be in the public interest.
2. The code acts to protect the interests of facility owners by requiring the regulator to provide network service providers with a reasonable rate of return.
3. The code acts to promote the interests of network service providers, users and the public by including an incentive mechanism (eg a CPI–X revenue and/or price cap) to encourage network service providers to continually improve productivity and to share the benefits between their shareholders and network users.
4. The code acts to protect the interests of access seekers by requiring network owners to respond to connection applications within specified time periods. If access negotiations are unduly protracted, access seekers can utilise the code's dispute resolution procedures or, in the last resort, to by-pass existing networks.

5. The code acts to protect the interests of both network service providers and users as it retains sufficient flexibility to allow negotiated connection agreements to be tailored to the meet the demands of specific connection proposals.
6. The code acts to promote the interests of network service providers, users and the wider public by providing for network augmentation to meet continually growing demand for electricity and new connection applications. The code does not preclude the possibility that all such augmentations could be contestable and includes administrative mechanisms to allow system wide planning to occur.
7. The code acts to protect the interests of network service providers, users and the wider public by including technical requirements, review and enforcement procedures which make it possible for networks to be operated within known technical and legal boundaries in order to minimise risks to the health, safety and property of connected users.
8. The code acts to protect the interests of network service providers and users as it requires network service providers to establish their own dispute resolution procedures. Failing the successful outcome from internal procedures, the code outlines enforceable dispute resolution procedures which can forestall protracted and costly legal procedures.
9. The code recognises there are existing network connection arrangements in each of the participating jurisdictions, and it allows them to be modified in an orderly manner in the transitional phase through to the end of the year 2002.

While the Commission accepts that, on balance, the access code is in the interests of facility owners, access seekers and the general public, the Commission is also of the view that much can be done to improve the access arrangements in the NEM. Many of the deficiencies are complex and the Commission accepts the need for a number of reviews. The applicant also accepts the need for a number of reviews and, in response to the authorisation determination and access code draft decision, have:

- amended the code to require annual reviews of NEMMCO's use of its powers of direction and to report on the viability of market provision of ancillary services; and
- given commitments to review certain aspects of network pricing, firm access, metering, facility inspection and dispute resolution as well as the legal framework governing the operation of both NECA and the National Electricity Tribunal.

However, commitments to review a problem are no guarantee that a solution will be implemented. Consequently, the Commission wants to highlight its remaining concerns in the balance of the protections the code and the National Electricity Law provide to affected parties in relation to disconnections and code breaches (eg the code is silent on procedural fairness issues in relation to NECA's enforcement processes and decisions).

To the extent that it is the National Electricity Law which is deficient, then the problems fall outside the scope of the access code and the direct sphere of NECA's responsibilities. While the individual deficiencies are unlikely to bring into question the enforceability of the code, collectively they create uncertainty of procedure and outcome. For this reason, the Commission believes the participating jurisdictions and NECA should conduct a review of the interaction of the National Electricity Law, the code and jurisdictional regulations.

In a similar vein, the Commission maintains its concerns about the cost of metering and implementing practical alternatives for metering smaller customers. To a large extent these concerns have not been raised in the context of the access code and the wholesale market (ie large users), but rather the retail market and smaller users. Effective resolution of these matters will require establishing seamless metering arrangements between the code (which largely deals with the single wholesale market in the NEM) and the regulation of retail competition in each of the participating jurisdictions. Unless the jurisdictions and the NEM administrators are able to address industry and public concerns, there is a danger that the benefits of retail competition may not be passed through to smaller customers.

1. The electricity supply industry and the access code

On 28 April 1997, the Commission received an application to accept an industry access code under Part IIIA of the TPA for electricity transmission and distribution facilities in the Australian Capital Territory, New South Wales, South Australia, Queensland and Victoria. The application and supporting submission were lodged by the National Electricity Code Administrator (NECA). The access code sets out the proposed rules for access to transmission and distribution facilities in the National Electricity Market (NEM).

This report outlines the Commission's current analysis and decision on the access code application. This decision follows extensive public consultation with the applicant and interested parties, release of a draft decision and convening of a pre-decision conference.

This initial chapter provides some background information by documenting the importance attached to the successful implementation of electricity reforms (section 1.1), the recent competition policy reforms (section 1.2) and reform of the electricity industry (section 1.3). The details of the national access arrangements, as contained in chapters 1, 2, 4, 5, 6, 7, 8, 9 and 10 of the National Electricity Code, are briefly summarised in section 1.4. The Commission's statutory assessment criteria and approach are documented in chapter 2. The remaining chapters detail the Commission's assessment of the access code.

1.1 The importance of electricity reform

The importance of the continued reform of the ESI is underscored by the dominant role the industry plays in the Australian economy as well as by the size of the potential benefits that are likely to accrue from the successful implementation of the reforms.

Electricity is one of the larger infrastructure industries, contributing 2.2 per cent of GDP ($9 billion) and 18 per cent of Australia's energy needs (ABARE 1997). On average electricity comprises 3 to 5 per cent of industry costs (considerably more for energy intensive industries like smelting and ferrous metals) and 2 per cent of household expenditure. Electricity generation accounts for around 65 per cent of the Australian ESI's total costs, transmission 10 per cent and distribution 25 per cent.

The importance of continued electricity reform is emphasised by estimates which indicate that the gains from improved performance of the electricity industry could increase GDP by up to $5.5 billion (1.3 per cent of GDP) — about a quarter of all the benefits from competition reforms (IC 1995).

The successful implementation of the NEM and the associated access arrangements will play a central role in achieving these gains. For example, the Productivity Commission's (1996) international benchmarking report argues that an interconnected electricity grid, which provides opportunities for power exchanges between the states, would allow the electricity generators to make better use of capital assets and thereby to reduce excess capacity and improve productivity. In turn, these gains will play an important role in raising the living standards of Australians and in promoting the international competitiveness of Australian businesses. The proposed arrangements may also facilitate the introduction of new technologies and demand side solutions which would allow Australia to address some of the concerns relating to greenhouse gas emissions through a 'no regrets' policy.

However, this need to raise living standards and the competitiveness of businesses by continually improving the performance of the ESI is recognised not only in Australia but in a number of other countries as well. For instance, the United States of America, England and Wales, New Zealand, Spain, Norway and Sweden have introduced, or are implementing, significant reform of their electricity industries. These overseas developments place pressure on Australian policy makers to continually reform the electricity supply industry (ESI) with a view to raising its performance standards. Moreover, Australia can learn from these overseas developments as some of the reforms that are under way in Australia, have occurred in other countries. Nevertheless, it must also be recognised that in many respects the reform process in Australia is breaking new ground on the world stage.

1.2 Recent competition policy reforms

In 1991 the Council of Australian Governments (COAG) resolved to examine a national approach to competition policy as an extension of the national micro-economic reform agenda. The first step in this process was to establish the National Competition Policy Review which was chaired by Professor Fred Hilmer.

On the completion of the Hilmer Committee's report in August 1993, Commonwealth, State and Territory Governments began extensive negotiations to implement its recommendations. This process culminated in June 1995 in the *Competition Policy Reform Act 1995* which, when coupled with two inter-governmental agreements (the Competition Principles Agreement and the Competition Code Agreement), resulted in a number of wide ranging reforms including the creation of a legal framework to establish access rights to services provided by nationally significant infrastructure facilities.

The legal framework, embodied in Part IIIA of the TPA and the inter-government agreements, created three approaches to third party access, namely:

- declaration of a service;
- recognition of effective access regimes; and
- access undertakings or codes accepted by the Commission.

The ESI in Australia has followed this latter route and NECA has submitted to the Commission an application for an access code for electricity related services provided by transmission and distribution facilities in the NEM. This approach will ensure that the access regime will comprehensively cover the NEM and will provide a streamlined process for assessing and accepting individual access undertakings. Provided they conform to the access code, the access undertakings submitted by individual network service providers could be approved by the Commission without a further public consultation process.

1.3 Recent reforms in Australia's electricity supply industry

Reform of the electricity supply industry has operated in tandem with the broader competition policy reforms. In general, the electricity reforms have sought to create an environment where the contestable parts of the industry are exposed to competition in order to create pressures to achieve resource allocation and efficiency goals.

Since the mid–1980s, the ESI has undergone significant changes to improve performance. Early reforms focussed on efficiency improvements, such as increasing labour productivity. More recently, the emphasis has been on more wide ranging administrative and structural reforms of the industry.

Administrative reform of the ESI covers a broad range of policy changes such as the corporatisation of electricity utilities, the creation of a more competitively neutral operating environment (eg separation of commercial and regulatory functions and imposition of tax equivalent and dividend payments) and the establishment of independent pricing authorities. These reforms have been particularly significant in the natural monopoly sectors. Administrative arrangements have also dealt with transitional issues including the franchising of some customers to specific retailers and vesting contracts for generators.

The extent of structural reform of the ESI has differed between jurisdictions but has generally involved separating the more contestable segments of the industry (ie generation) from the natural monopoly elements of the industry (ie transmission and distribution). In some jurisdictions, structural reforms have also increased competition by splitting the various activities of the industry into separate competing companies (eg generation). In addition, a number of the generation and distribution companies have been privatised. These structural changes have often been accompanied by changes in the regulatory arrangements.

One of the major objectives of these reforms has been to improve price signals in the ESI. In most jurisdictions, tariffs have been traditionally regarded as being structured to provide cross–subsidies between business consumers and residential consumers and between city consumers and consumers in rural areas. The extent of these cross-subsidies are gradually being wound back.

These electricity industry reforms were provided a national focus at the July 1991 Special Premiers Conference, when Heads of Government agreed to establish the National Grid Management Council (NGMC). The NGMC was set the task of encouraging open access and free trade in bulk electricity and the development of the interstate electricity supply industry in eastern and southern Australia in a way which is as efficient, economical and environmentally sound as possible.

In 1993, governments represented on the NGMC agreed that a Multiple Network Corporation structure would be in place by 1 July 1995. The model requires each jurisdiction to separate the network (transmission and distribution) businesses from the other elements and subsequently to corporatise the new network businesses. These arrangements have dovetailed into the competition policy reforms and have led to developing the National Electricity Code, parts of which deal with the proposed access arrangements which are the subject of this assessment.

1.4 The National Electricity Market and the proposed access code

The final version of the code submitted to the Commission has been endorsed by all the participating jurisdictions — New South Wales, South Australia, Victoria, Queensland and the Australian Capital Territory. These jurisdictions have agreed to enact cooperative legislation to implement the regulatory arrangements, called the National Electricity Law. The legislation will give effect to the identical form and effect of the code in participating jurisdictions at all times, subject to derogations. Tasmania is expected to join the national electricity market some time in the future.

The code was prepared by the NGMC on the basis of industry wide consultations on possible systems, market mechanisms and regulatory measures. A series of working groups were also established to develop the detail of the agreed market structure, taking into account the physical limitations that exist in the system. The NEM Code is designed to set out the rules governing the operation of the national market, market trading rules, network pricing principles, systems control and access to the network, as well as the rights and obligations of the participants.

The stated objective of the code, as agreed by all Australian governments, is to provide a regime of light–handed regulation of the market to achieve the market objectives, which are stated as:

- the market should be competitive;
- customers should be able to choose which supplier (including generators, retailers and traders) they will trade with;
- there should be non–discriminatory access to the interconnected transmission and distribution network;
- there should be no discriminatory legislative or regulatory barriers to entry for new participants in generation or retail supply; and
- there should be no discriminatory legislative or regulatory barriers to the interstate and/or intrastate trading of electricity.

Trading in the wholesale electricity market will include bilateral contracts, short term forward market trading, spot trading and inter-regional hedging (for further details see

Box 1.1). The code will not cover arrangements for bilateral contracts, nor will it extend to the arrangements for retail trading. These trading roles are not the subject of the access arrangements to the wires infrastructure, although they are the subject of a separate authorisation determination.

Central to the success of the NEM is the access arrangements which will apply to the transmission and distribution systems. Changes in technology over recent years have demonstrated that the generation of electricity is not a natural monopoly. It has also been established that the retailing of electricity is also an area into which competition can be introduced. Nevertheless, establishing competition in upstream and downstream markets and acquiring the associated benefits, is dependent on those sectors (generation and retail) being able to obtain open and non–discriminatory access to the wires infrastructure.

It is generally accepted that the wires infrastructure of transmission and distribution is a natural monopoly, although this does not prevent introducing some competitive pressures. For instance, designing and constructing network augmentations can be contracted out through a transparent competitive tendering process. While such a process may serve to reduce costs, they do not alter the natural monopoly status of network owners. Indeed, network owners could use their dominant position in the market to retain any of the benefits from increased competition in generation and to crowd-out any viable alternatives to network augmentation (eg embedded generation and demand side management). Consequently, it is important that there continues to be regulation of the services provided by transmission and distribution wires.

Box 1.1: Overview of operation of the National Electricity Market

In the NEM generators will compete by lodging bids to supply electricity to a common pool for half hour periods. Bids will consist of a schedule of the price and quantity of electricity a generator is willing to dispatch. Bids will be lodged 24 hours in advance with the central grid operator — ie the National Electricity Market Management Company (NEMMCO). Nevertheless, rebidding is allowed in order to provide generators with the flexibility to respond to unforseen circumstances.

NEMMCO ranks generator bids in merit order according to their bid price. Based on expected demand, NEMMCO determines which generators will operate in a particular half hour period. Unless the system is constrained, NEMMCO will only dispatch those generators which bid at or below the spot or market clearing price. Generators will receive the market clearing price for dispatched electricity and not their final bid price.

In general, all electricity dispatched into the pool must be traded through the spot market. Nevertheless, it is envisaged that the bulk of electricity will be covered by financial contracts to manage the price and volume risks of the wholesale market (eg long term, financial hedging and short term hedging contracts).

Wholesale traders (eg licensed retail suppliers and large electricity customers) will compete to purchase electricity either from the pool or under contracts directly with the generators. Licensed retail suppliers can on-sell electricity to businesses, households and intermediaries. Where retail suppliers also own distribution networks, the two activities must be ring fenced. In addition, other retail suppliers must be able to access their network on the same terms given to their own retail supply business. Progressively, regional retail supply monopolies are being abolished and customers are increasingly able to choose their own retail supplier.

According to NECA's application, the NEM access code is principally comprised of chapters 4 to 9 of the NEC but it also encompasses the relevant parts of the remaining NEC chapters as well as the applicable regulatory instruments of the participating jurisdictions.

Reflecting the need for flexibility, NECA has proposed an access code which specifies in some detail:

- the framework for achieving and maintaining a secure power system (chapter 4 of the NEC);
- the framework for generators and users to connect to an electricity transmission or distribution network (chapter 5 of the NEC), including;
  - a requirement to negotiate and sign a detailed connection agreement;
  - agreeing on connection equipment design and technical standards;
  - the inspection, testing and commissioning requirements for connected equipment; and
  - disconnection procedures;
- investments in networks (chapter 5 of the NEC) are governed either by:
  - commercial arrangements, in the case of new or upgraded connections; or
  - administrative planning processes, in the case of a general increase in demand or either within a network or across a range of networks;
  - the pricing regulatory arrangements (chapter 6 of the NEC) to be followed by: the ACCC in setting a revenue cap for transmission network providers; and the state and territory regulators in setting a revenue and/or price cap for distribution network service providers;
- the rights and obligations of network service providers and users in measuring electrical energy and providing data for operating the market (chapter 7 of the NEC);
- the dispute resolution and enforcement mechanisms (chapter 8 of the NEC) consisting of administratively created arbitrators, panels and tribunal, backed-up by relevant courts in each jurisdiction and based on the National Electricity Law (to be enacted in each of the participating jurisdictions); and
- the derogations which outline the scope of the transitional arrangements which will apply in each of the jurisdictions for a specified period of time (chapter 9 of the NEC).

2. Assessment procedures for the access code

As this is the first occasion the Commission has been requested to assess an access code under Part IIIA of the TPA, the administrative procedures and assessment criteria are new to both the Commission and all interested parties. In this assessment of the National Electricity Market's access code, the Commission has adopted administrative procedures which are similar to those which apply to authorisation applications. On this occasion this is a pragmatic approach as the arrangements detailed in the code have been submitted to the Commission for acceptance as an access code as well as for authorisation. Nevertheless, our approach to assessing access codes and undertakings can be expected to evolve over time in response to changing circumstances and feedback from participants.

This chapter outlines the Commission's approach to assessing the access code for the National Electricity Market. The chapter begins by outlining the Commission's statutory requirements for assessing access codes under Part IIIA of the TPA (section 2.1). The chapter goes on to provide some guidance as to how the Commission has interpreted the statutory criteria for assessing access codes (section 2.2) and, in doing so, draws heavily on the Commission's guide: Access Undertakings. The chapter concludes by documenting the Commission's public consultation procedures in the course of assessing the access code (section 2.3).

2.1 The statutory test

Part IIIA of the TPA provides two mechanisms for bringing an access regime to the Commission for acceptance. The first mechanism allows an individual service provider to give an access undertaking to the Commission. The second mechanism allows a prescribed industry association to give an industry-wide access code to the Commission for acceptance and for individual service providers to make an undertaking to conform to the code. This latter mechanism is particularly designed for network facilities and ensures that the access arrangements are uniform and comprehensive. It also avoids unnecessary duplication of assessment procedures for conforming access undertakings.

NECA's application was made under section 44zzaa of the TPA. The section provides an opportunity for an industry body to give a written code to the Commission setting out the rules for access to a service as well as indicating the date at which the code will expire.

In assessing the merits of the code, the Commission is required to follow a public process by publishing the code and inviting submissions. In assessing whether to accept an access code, sub-section 44zzaa(3) of the TPA requires the Commission to have regard to:

a) the legitimate business interests of providers who might give undertakings in accordance with the code;
b) the public interest, including the public interest in having competition in markets (whether or not in Australia);
c) the interests of persons who might want access to the services covered by the code;
d) whether the service is already the subject of an access regime;
e) matters specified in regulations, in particular:
    i) government legislation and policies relating to ecologically sustainable development;
    ii) social welfare and equity considerations, including community service obligations;
    iii) government legislation and policies relating to matters such as occupational health and safety, industrial relations and access and equity;
    iv) economic and regional development, including employment and investment growth;

v) the interests of consumers generally or of a class of consumers;
vi) the competitiveness of Australian businesses;
vii) the efficient allocation of resources; and

f) any other matters the Commission thinks are relevant.

Subsequent to the Commission's final acceptance of the access code, individual network service providers will submit access undertakings which conform to the access code. The Commission cannot accept an access undertaking if the service is a declared service under sub-section 44h(1) of the TPA.

Part IIIA of the TPA does not provide a separate mechanism for parties to appeal the Commission's decision relating to an application for an access code or undertaking. More generally, however, a person can apply to the Federal Court for an order or declaration concerning the validity of any action performed under the TPA [s.163A]. Furthermore, the Commission's decisions are subject to judicial review under the *Administrative Decisions (Judicial Review) Act 1976*. Such a review would not go to the question of merit of the NEM's code but rather how the Commission's decision was made in terms of the provisions of the TPA and application of administrative law.

2.2 Application of the statutory test

The access code assessment criteria are general in nature, focusing on the interests of the various parties as well as the public interest. Moreover, they do not detail the weighting that should be given to the various criteria. As this is the Commission's first assessment of either an access code or undertaking, there is no clear direction as to how the Commission should apply each criteria nor to the balance that should be struck between the diverse interests represented by the criteria.

In assessing the interests of service providers, the Commission has relied heavily on the application submitted by NECA. The Commission's assessment of user interests has also relied heavily on the submissions received through the public consultation processes.

It is, however, more difficult to rely solely on public submissions to identify and assess the broader public interest, in particular how the access code will contribute to improving the welfare of the broader community. This is because it is sometimes difficult to disentangle the public interest arguments from the private interests of those presenting submissions. Consequently, the Commission's assessment of the public interest has, to a large extent, been guided by the statutory requirements which emphasise the need for the access code and undertakings to have beneficial competitive outcomes in other markets. Regulations also indicate that the public interest covers a broad range of other issues such as equity, consumer interests and safety.

The TPA also establishes a more general assessment criteria which allows the Commission to assess an access code and undertaking with respect to 'any other matters that the Commission thinks are relevant'. With respect to this criteria, and in the context of the National Electricity Market access code, the Commission has also taken into consideration:

1. Government preferences in relation to matters such as uniformity, transitional period, asset valuation methodologies, CSOs and service provider specific regulations. Nevertheless, the Commission will consider the extent to which such requirements are binding and whether they unnecessarily impede competition.
2. Other areas of the TPA and the *Prices Surveillance Act 1983* which are not covered by Part IIIA.
3. The likely effectiveness of the code's in-built administration, enforcement and appeal mechanisms, in particular their ability to manage unforseen contingencies and to handle disputes in according to the rules of natural justice and in a transparent manner.

In summary, the Commission's assessment and conclusions on the access code for the NEM, has weighed up the interests of providers and users, taking into account submissions as well as the access code itself. In determining the public interest the Commission has primarily relied upon an economic efficiency and its ability to enhance the welfare of Australians which includes material well being as well as equity and environmental concerns.

2.3 Public consultation process

Prior to receiving the formal application for an access code the Commission sought submissions from, and undertook discussion with, a cross–section of interested parties on the competition and access issues arising from the draft version 1.0 of the code which was circulated for public comment by the NGMC in March 1996.

The Commission released National Electricity Market — Issues Paper in March 1996. The issues paper was produced to facilitate public discussion on the competition, access and public benefit implications of the draft code. The objective was to improve the code before its formal submission to the Commission for its assessment as an access undertaking as well as for its authorisation.

Thirty two written submissions were received in response, and the key issues arising from submission and the Commission's preliminary analysis of the competition and access issues raised in the code were published in a paper the National Electricity Market Code of Conduct — Comments and Issues Arising.

On receipt of the formal application for acceptance of the NEM Code as an access code on 28 April 1997, the Commission informed the public of the receipt of the application by contacting interested parties and undertaking discussions with a cross section of interested parties on the access issues arsing from the code. Interested parties were asked to make submissions to the Commission regarding their views on the code in relation to Part IIIA criteria on which the Commission is to have regard to in making its decision. In response to the Commission's request, submissions were received from 45 different organisations and individuals, the majority of which commented on access as well as authorisation issues.

To assist the Commission's assessment of the access code, three consultants were engaged by the Commission. Western Power Corporation assessed the technical provisions in the code and Colin Taylor and Associates reviewed Western Power's findings. The National Economic Research Associates (NERA) were engaged to review Victoria's proposed derogations regarding the regulation of transmission network pricing.

On the basis of the Commission's own analysis, input from submissions and public consultations, the Commission produced a Draft Decision on 29 August 1997. In the context of the Authorisation of the code's market arrangements, the Commission is obliged to provide the opportunity for a conference of interested parties, before making a final decision whether to grant authorisation. The Commission took that opportunity to discuss with interested parties the access code before making a final decision on its acceptance.

The pre-decision conference was held in Melbourne (with video links to Sydney, Brisbane, Canberra and Hobart) on 18-19 September 1997. Around 92 interested parties attended the conference.

Interested parties were given an opportunity to submit further submissions to the Commission following the pre-decision conference. The Commission received 52 submissions addressing a range of access and authorisation issues raised at the conference or in the draft decision. This decision takes into account the issues raised at the pre-decision conference and in submissions.

3. Network pricing

Asset values, rates of return and pricing structures are generally determined by the interaction of the forces of demand and supply. In doing so, prices act as a signalling device to producers and consumers concerning the: demand for the use of a facility and alternative sources of supply; utilisation of existing assets; investment in new facilities; and redundancy of obsolete facilities.

In a competitive market, these various price signals reflect a balancing of the costs of supply and the value attached to consumption. In such circumstances, prices can lead to efficient production and consumption outcomes with consequential benefits for community well being.

Conversely, in markets which are not competitive, nor even contestable, there exists an imbalance of the relative bargaining position of producers and consumers. Consequently, prices can be distorted thereby losing many of their desirable features with a resultant adverse impact on economic efficiency and community well being. In such circumstances, governments have attempted to rectify these market failures by intervening through ownership, regulation or some combination of both.

However, finding solutions to these problems is generally complex and information intensive so perfect answers are rarely found. The pricing section of the NEM access code attempts to deal with these problems by removing from network owners a significant amount of discretion in terms of price setting. The code proposes establishing separate, but similar, mechanisms for pricing access to transmission and distribution networks whereby government appointed regulators will determine asset values, rates of return and revenue and/or price caps. The code outlines principles, objectives and cost allocation procedures to guide regulators and NSPs through this process.

This chapter commences with a summary of the pricing issues which the Commission considers are important in assessing the access code's proposed pricing regime (section 3.1). The chapter is then divided into four parts: part A examines the regulatory regime for transmission revenue (section 3.2) and the transmission pricing methodology (section 3.3); part B examines the regulatory regime for distribution pricing (section 3.4) and the distribution pricing methodology (section 3.5); part C examines asset valuation methodology (section 3.6) and issues associated with cogeneration and embedded generators (section 3.7); and part D examines the longer term transmission derogations for South Australia (section 3.8) and Victoria (section 3.9).

3.1 Network pricing issues

The requirements governing network pricing is a central part of any access code or undertaking. Consequently, the Commission would have to be satisfied that the arrangements represent an appropriate balance of the interests of the network owner, those seeking access and the general public.

The Commission is of the view that network pricing and regulation proposals should be designed to achieve the main objectives of effective network pricing, that is to:

- prevent monopoly rent-taking by network owners; and
- provide efficient market signals for the use of existing network facilities and for future investments in the network.

Ideally the pricing structure should provide price signals which reflect the extent of congestion or spare capacity at differing points of the network and so influence the pattern of demand for network services. It should also provide efficient signals for augmenting congested parts of the network.

To achieve these objectives, the Commission will have to be satisfied that the proposed access pricing arrangements are consistent with the legitimate business interests of the NSPs; in particular, that NSPs are able to earn a commercial rate of return on their investments. While NSPs should not be protected from normal commercial risks, the access regime should not require them to undertake investments which are uneconomic and should not stifle commercially sound investment opportunities. In addition, an access code should not impose obligations onto an NSP which places them at a competitive disadvantage in their contestable activities. These protections on the business interests relate to all of the access code's pricing obligations, irrespective of whether they were designed to facilitate connection for third parties or to achieve other objectives (eg CSOs).

The Commission will also have to be satisfied that the NEM access code is consistent with the interests of third party access seekers. In this context, access pricing arrangements:

- should reflect efficient costs and not monopoly profits nor cost padding including 'gold plating' of investments and excessive remuneration of staff;
- should reflect an access seeker's use of the network and not discriminate between users or technologies;
- should provide appropriate locational signals for users; and
- should not be used be used to frustrate connection or hinder access.

Other desirable features of the access pricing regime is that it should be flexible for individual circumstances and include incentives for the NSP to improve efficiency over time and to share any such efficiency improvements with network users. In a similar vein, the pricing regime should allow efficiency improvements achieved elsewhere (eg generation or retail) to be passed on to users and not to be wholly captured by the NSP.

In terms of the public interest, the Commission will have to be satisfied that the NEM's network access pricing regime is capable of promoting community welfare and that any benefits of reform and efficiency improvements are not wholly captured by the NSPs or by code participants. Again, this requirement precludes monopoly pricing of network facilities. However, the arrangements should not preclude the ability of governments to seek to achieve other objectives in relation to equity, environmental amenity and consumer protection. Moreover, as the networks have been characterised by cross-subsidies, a desirable feature of the pricing regime would be to avoid price shocks to particular consumers, or classes of consumers, and include transitional arrangements whereby the move towards more cost reflective pricing is phased-in.

In addition, the Commission would have to be satisfied that in meeting these objectives, the proposed pricing regulatory regime is not overly burdensome for NSPs and regulators in terms of time and resources; for example, a pricing regime which draws a large amount of a NSP's managerial resources away from their primary objectives of operating increasingly efficient networks is unlikely to be in the interests of the NSPs, network users or the public. Also, as the code provides for significant parts of the pricing decision to be undertaken by regulators, the code will have to establish mechanisms to overcome information asymmetry.

Part A Transmission

3.2 Regulatory regime for transmission revenue

3.2.1 What the applicant says

The applicant (sub. p. 231) indicated that the code will establish an effective 'light handed' pricing regulatory regime which safe guards consumers from the exploitation of monopoly power. To achieve this the code does not attempt to limit or prescribe the methodologies to be applied by the regulator. Rather, the code outlines a number of objectives and principles (see Box 3.1) to be followed by the regulator when determining maximum network revenues (ie the revenue cap).

In the longer term, the ACCC will be the regulator of transmission network pricing. The ACCC's pricing regulatory functions will start from 1 July 1999 in the Australian Capital Territory and New South Wales, from 1 January 2002 in Queensland and from 1 January 2003 in South Australia and Victoria, or earlier if mutually agreed by the ACCC and the jurisdictional government. In the interim, jurisdictional regulators will regulate transmission network pricing in accordance with the transitional arrangements determined by the jurisdictional derogations and the evolving jurisdictional access regimes (for details of the transmission pricing derogations see Table 3.1). Prior to the draft decision, South Australia and Victoria proposed longer term derogations which are discussed in part D of this chapter.

Table 3.1: Derogations for regulatory regime for transmission pricing

State	Expiry date	Details
Victoria	31/12/2002	• transitional transmission pricing arrangements will be regulated by the EI Act, ORG Act and the Tariff Order;
	30/6/2020	• Tariff Order equalisation adjustments apply;
New South Wales	1/7/1999	• transitional transmission pricing arrangements will be regulated by the IPART Act and any subsequent IPART determinations;
Queensland	31/12/2001	• transitional transmission pricing arrangements will be regulated by the QCA Act and Electricity Act;
South Australia	31/12/2002	• transitional transmission pricing arrangements will be determined by the South Australian Government;

Box 3.1: Overview of transmission pricing objectives and principles

The code establishes that:

1. the transmission pricing regulatory regime must achieve outcomes which:
   a) are efficient and cost effective;
   b) are incentive based and provide a reasonable rate of return (without monopoly rents) to network owners;
   c) foster efficient investment, operation and use of network assets;
   d) recognise pre-existing government policies on asset values, revenue paths and prices;
   e) promote competition; and
   f) are reasonably accountable, transparent and consistent over time.
2. the regulation of aggregate revenue of transmission networks must:
   a) be consistent with the regulatory objectives (see 1 above);
   b) address monopoly pricing concerns, wherever possible, through the competitive supply of network services but otherwise through a revenue cap;
   c) promote efficiency gains and a reasonable balance between supply and demand side options;
   d) promote a reasonable rate of return to network owners on an efficient asset base where:
      i) the value of new assets are consistent with take-or-pay contracts or NEMMCO augmentation determinations;
      ii) the value of existing assets are determined by jurisdictional regulators and must be lower than their deprival value;
      iii) any asset revaluations undertaken by the ACCC are consistent with COAG decisions;
3. the form of the economic regulation shall:
   a) be a CPI–X revenue cap, or an incentive based variant, for each network owner;
   b) have a regulatory control period of at least 5 years;
   c) take into account expected demand growth, service standards, cost of capital, potential efficiency gains, risk and on-going commercial viability;
   d) only apply to those assets the ACCC does not expect to be offered on a contestable basis;
4. the transmission NSPs must provide the ACCC with annual financial statements, and other information as required, so the ACCC can monitor compliance with the revenue cap and assess cost allocation;

Source: NGMC 1996, National Electricity Code.

In addition to protecting consumers from the abuse of monopoly power, the applicant (sub. p. 232) characterised the transmission revenue regulatory regime as an incentive based regime which:

- equitably allocates the anticipated efficiency gains between transmission network users and transmission network service providers; and

- provides for a sustainable commercial revenue stream to the transmission network service providers.

The applicant indicated that in opting for a pricing regulatory regime based on a revenue cap, they had considered but rejected as inappropriate alternative options. For example, the applicant (sub. pp. 240–1) argued that given the monopoly characteristics of the transmission sector:

- commercial negotiation of terms and conditions for access to existing facilities is unlikely to lead to timely and efficient outcomes; and
- prices surveillance is inappropriate where the service is founded on an essential facility with substantial monopoly characteristics in an immature market with powerful incumbents.

The applicant (sub. pp. 232–3) indicated that given the cost structure of transmission activities (ie capital intensive and assets with long lives), the pricing regulatory regime must protect the industry's investments as transmission assets have little or no value in an alternative use. Without such protections, the applicant argues that capital markets could not be confident that new network investments would earn an appropriate return which would thereby increase the costs to users of any network expansions.

The applicant went on to argue that the code protects the NSPs' interests by requiring the ACCC to administer a regulatory regime which provides NSPs a reasonable rate of return on efficient investments, operating and maintenance practices as well as allowing them to retain a proportion of any efficiency gains.

The applicant argued that the transmission revenue regulatory regime protected the public interest in a number of different ways. First, the applicant (sub. p. 234) stated that the code allows for the periodic revaluation of an NSP's assets (based on the deprival value approach) so prices reflect efficient costs and NSPs make efficient investment decisions — see section 3.5 for a detailed discussion of asset valuation issues.

Second, the applicant (sub. p. 236) argued that the regulatory regime provides the regulator (ie the ACCC) with reasonably well defined regulatory discretion to balance the interests of service providers, users and the public; in particular, as the code provides the ACCC with the flexibility to 'develop and apply its own working definition of 'public interest'.'

Third, the applicant argued that by allowing new network services to be contestable 'the 'natural monopoly' status of incumbent regional network owners' is diminished. However, as the applicant (sub. p. 237) recognised, other issues dealing with competitive neutrality and further structural reform of public monopolies is at the discretion of the various jurisdictions.

Fourth, the incentive based revenue cap allows the NSP to retain the benefits of reducing costs below the assumptions used to determine the cap. Consequently, the applicant argued that (sub. pp. 237–8) the regulatory regime creates clear incentives for NSPs to maximise efficiency in both operations and capital expenditure which are required to be equitably shared between the NSP and the service users.

The applicant argued (sub. pp. 238–9) that the interests of NSPs and users are adequately balanced as the code: provides the ACCC with pricing regulatory powers; permits bypass to occur; and prohibits double charging by ensuring that any capital contributions are taken into account when setting charges.

In response to the Commission's earlier concerns that the code did not adequately reflect emerging experience on network pricing in Australia and overseas, the code establishes a NECA review of the pricing requirements applying to transmission networks and associated connection assets. This review has commenced, is anticipated to be completed in September 1998 and may make recommendations to alter the code.

3.2.2 What the participants say

In submissions to the Commission, participants identified two major concerns with the code's proposed transmission pricing regime. First, participants were concerned that the code's proposal to use the deprival methodology to value assets would lead to higher network charges. Given their importance, these issues are examined separately in section 3.5. Second, participants expressed doubts on whether the proposed transmission pricing regime, which is based on a cost of service revenue cap with a CPI–X incentive mechanism, is likely to result in transmission charges which are low by international standards. For example, while the Energy Users Group (EUG) supported the inclusion of the regulatory objectives in the code, they argued that the transmission pricing principles should place greater emphasis on the need for users to have access to internationally competitive transmission charges. The EUG (sub. p. 62) argued that, in contrast to the proposed arrangements, end users preferred some of the alternative approaches to incentive-based regulation that are used overseas (eg the California Public Utilities Commission's approach to the regulation of gas pipelines which relies on yardstick competition to determine price targets).

3.2.3 The Commission's considerations

The approach adopted for charging for access to the NEM's transmission networks is based on a set of principles and objectives which attempt to reflect the competing needs of NSPs, network users and the wider Australian community. The central feature of the arrangements is that a government regulator will undertake periodic reviews of network costs and sales forecasts to determine a revenue cap for the NSP. Based on the revenue cap, the NSP is responsible for allocating costs amongst different services and thereby deriving a range of access prices. The NSP is encouraged to operate efficiently through the application of a CPI–X incentive mechanism on the revenue cap. In addition, the code requires the regulator to assess the revenue cap on the basis of efficient operating and maintenance costs and on an asset base which is capped at the deprival value. This asset valuation methodology allows the regulator to choose a current cost valuation but also allows it to 'strand' assets which are in excess of forecast needs or which have been 'gold plated'. In the longer term, the code provides for a single regulator (ie the ACCC) of transmission pricing to ensure a degree of consistency in the application of the transmission pricing principles.

The Commission accepts the applicant's broad arguments that the NEM access code's pricing principles for transmission networks contain many aspects which act to protect the legitimate business interests of NSPs, access seekers and the public more generally. Of particular significance is that the access code:

- acts to protect the interests of the facility owner by requiring the regulator to provide NSPs with a revenue which is sufficient to recover efficient costs and earn a reasonable return on efficient investments;
- acts to protect the interests of network users and the public by depriving NSPs of the power to unilaterally exploit monopoly power by establishing a price regime to be administered by a single regulator (ie the ACCC);
- acts to protect the interests of NSPs, network users and the public by including incentive mechanisms which encourage NSPs to continually improve productivity and to share the benefits between their shareholders and network users; and
- acts to protect the interests of NSPs, network users and the public by providing the regulator with the flexibility to periodically reassess the determinants of network prices (ie every 5 years) and, in doing so, to respond to changing circumstances.

Despite these generally positive features of the transmission regulatory regime, the Commission's draft decision drew attention to a number of outstanding issues associated with the proposed regulatory processes and with certain aspects of the regulatory mechanism itself.

Regulatory processes

The flexibility inherent in the transmission regulatory regime involves a trade-off as the outcomes of the processes will remain unknown for some time. This is exemplified in the situation whereby the code provides significant scope for the regulator to benchmark operating costs against world best practice and to strand 'gold plated' facilities when revaluing assets. In addition, the code includes incentive mechanisms to encourage NSPs to achieve on-going productivity improvements. Despite these arrangements, participants were critical of the code because there is no guarantee that the NEM will generate internationally competitive electricity prices. Similarly, participants were concerned that the deprival methodology could be used to systematically inflate asset values, thereby providing NSPs with monopoly style returns on funds outlaid (see section 3.6 for a discussion of this issue).

In essence, the question posed by participants was whether the access code provides the appropriate balance between regulatory flexibility and certainty of outcomes for NSPs, network users and the wider community. However, to provide a greater certainty of outcomes, the Commission has not sought changes to the code which would significantly limit the ability of regulators to periodically respond to new or changed circumstances. Consequently, the answer to the concerns posed by the participants depends on the effectiveness of the regulator.

As with all regulatory regimes, the performance of the regulator and the regulatory process depends on a combination of factors including: transparent, impartial and accountable decision making; access to relevant information; adequate resourcing; and effective sanctions for non-compliance with the code requirements or with regulatory directions.

In this context, the Commission places considerable weight on those code provisions (clause 6.2.5) which provide the regulator with the necessary powers to: determine the form in which an NSP will submit their annual financial statements; and verify or independently audit the information sought. Non-compliance with these requirements may result in both a breach of an NSP's access undertaking as well as a breach of the NEC. Consequently, an NSP may be required to comply with a Federal Court order and to pay a penalty for a breach of the NEC.

In line with the information disclosure requirements of the jurisdictional regulators in Victoria and New South Wales, the code recognises that the regulatory regime must balance the need for the processes to be transparent, for the regulator to be accountable and for the legitimate business interests of the transmission NSPs to be protected. For instance, in determining the revenue cap, the code requires the regulator to publish full and reasonable details of the basis and rationale of the decision. However, the code adds the restriction that the regulator treats all submitted information as confidential unless the regulator has the written approval of the transmission NSP.

In its draft decision, the Commission argued that, on balance, the code requirements are biased towards the interests of the transmission NSPs as it would provide them with an effective veto over the disclosure of information. As such, the code arrangements are inconsistent with the powers of other regulators such as the Office of the Regulator General (ORG) in Victoria which has the ability to release confidential information if it determines it would be in the public interest to do so — this power is also constrained by an appeal right (ORG Act s. 27C & 27D). Releasing information is important in ensuring the regulatory processes are transparent and subject to public scrutiny. However, it is equally important that an appropriate balance is maintained such as that achieved by the ORG Act which ensures that the regulator is accountable for its decisions and does not possess unlimited powers in this regard. Indeed, the regulator would not want to release all information supplied to it, in particular detailed information relating to unregulated activities which are subject to competition and market disciplines.

Consequently, in the draft decision the Commission stated:

> **The Commission believes the code should be altered to provide the transmission regulator with an ability to independently disclose information received. As with the ORG Act, these powers should be of a limited nature and subject to appeal.**

In addition, the Commission argued that the code should provide the regulator with the power to specify a date by which certified annual financial statements or requested information is to be provided by the NSP. The Commission's concern is that this oversight may result in an unreasonable delay in the NSP providing required and requested information to the regulator. If this was to occur, the revenue cap setting processes and enforcement procedures may become ineffective. Consequently, in the draft decision the Commission stated:

> **The Commission believes that clause 6.2.5 should include dates by which certified annual statements are to be provided by transmission NSPs to the regulator. Clause 6.2.5 should also provide the regulator with the ability to specify a reasonable period within which transmission NSPs are to respond to the regulator's requests for information.**

Issues arising in response to the draft decision

In response to the draft decision, the New South Wales distribution NSPs (sub. p. 4) and TransGrid (sub. p. 10) expressed concerns that the regulator should not attempt to run the network businesses. The New South Wales distribution NSPs acknowledge that the regulator should have reasonable information gathering powers while TransGrid argues that the standard financial reporting requirements would be sufficient. However, the distribution NSPs (sub. p. 4) stress that if the regulator has power to independently disclose information, then the networks should have appeal rights to a court of law in the event of a dispute.

Regulatory mechanism

The regulatory mechanism established by the code is a CPI–X revenue cap (or an incentive based variant) which applies to an NSP's non-contestable services where the regulator is expected to take into account a number of factors including expected demand growth, potential for efficiency gains and on-going commercial viability. In general, the Commission believes that this range of factors provides the regulator with significant flexibility to encourage efficiency improvements in the operation of transmission networks.

In determining the revenue cap the regulator is also required to take into account the service standards as specified elsewhere in the code or as determined between NSPs and network users. This requirement is important as the revenue cap should be determined on the basis of known service standards, otherwise once the revenue cap has been set, the NSP has an incentive to lower service standards in order to reduce costs and increase profits. In general, the Commission is supportive of this code requirement as it emphasises the need for service standards to be determined on a commercial basis between NSPs and network users.

However, some of the code's performance requirements on NSPs were not fully specified in recognition that levels of service will vary depending on the location of a connection point in a network. In such circumstances, the code requires an NSP to fully describe the quantity and quality of network services which it agrees to provide to a person under a connection agreement. This issue was raised in the context of connection agreements by a number of participants that argued the code does not provide them with sufficient protection from an NSP which has little regard to meeting a minimum level of service (for more details see chapter 4 of this report).

It is apparent, therefore, that the code does not, and perhaps cannot, fully specify minimum level of service standards which are applicable to all NSPs covered by the code. Consequently, the Commission shares a number of the participants' concerns that NSPs could use the flexibility in the code to reduce service standards to a level below that envisaged when operating and maintenance costs are determined at the time of the rate review. Consequently, the Commission's draft decision stated:

> **The Commission believes the code must be altered to provide the transmission regulator with the power to request that a transmission NSP to submit a service charter which fully specifies the service standards which will be met for the duration of a revenue cap period. The code must also provide the transmission regulator with the power to acquire the necessary information to monitor compliance with a network's service charter and to revoke or revise a revenue cap during a regulatory control period for any breaches of a service charter.**

The Commission argued that while the service standards should be driven by commercial considerations, such a service charter could serve two purposes. First, they would provide the basis upon which connection agreements would be negotiated. Second, they would form the basis on which the regulated revenue cap would be set thereby avoiding incentives for NSPs to reduce service standards within a rate period.

3.2.4 The applicant's response

The applicant argued that a service charter may not be the most appropriate mechanism to monitor compliance with a revenue cap and a set of consistent service standards. Consequently, the applicant argued that NECA's review of network prices would re-examine the issue of maintaining consistency between a regulator's revenue cap determination and a network's service standards. Specifically, these issues are addressed in item 5 of NECA's Terms of Reference for its Transmission and Distribution Pricing Review which states, amongst other matters, that the review will consider:

- the appropriate powers of transmission and distribution regulators in particular in relation to the development and monitoring of service charters drawn up by transmission network service providers.

In response to the Commission's requirement that the code allow the regulator to determine the timing of a network's responses to a regulator's request for information, IN amended clause 6.2.5(a) and (c) of the code to state that:

> (a) The *Transmission Network Owner* and/or *Transmission Network Service Provider* (as appropriate) must submit certified annual financial statements to the *ACCC* (in a form <u>and by a date</u> to be determined by the ACCC) which provides a true and fair statement of the financial and operating performance of the *Transmission Network Owner* and/or *Transmission Network Service Provider* (as appropriate) in a reporting period.
>
> (c) In addition to the certified financial statements referred to in clauses 6.2.5(a) and (b), the ACCC may require a *Transmission Network Owner* and/or *Transmission Network Service Provider* (as appropriate) to provide any other information the ACCC reasonably requires to perform its regulatory functions in a manner <u>and by a date</u> it considers to be consistent with the requirements of clauses 6.2.2, 6.2.3 and 6.2.4.

In relation to the public release of information, the applicant agreed to the Commission's request and has amended the code to provide the transmission pricing regulator with the ability to release information but subject to certain constraints. In particular, clause 6.2.5(e) has been amended so it now states that:

(e) Information provided to the *ACCC* by a *Transmission Network Owner* and/or *Transmission Network Service Provider* (as appropriate) pursuant to this clause 6.2.5 must be treated as confidential by the ACCC and must not be disclosed to any other party without the prior written consent of the *Transmission Network Owner* and/or *Transmission Network Service Provider* (as appropriate) which provided that information unless the procedures set out in clauses 6.2.6 (b)-(e) have been followed.

Clauses 6.2.6 (b)-(f) have also been inserted:

(b) The *ACCC* in discharging its functions under the *Code* may publicly release information or the contents of documents provided to it by a *Transmission Network Owner* and/or *Transmission Network Service Provider* (as appropriate) for the purposes of performing its functions under the *Code* in circumstances where the *Transmission Network Owner* or *Transmission Network Service Provider* has declined to give written consent to its release in accordance with clause 6.2.5(e) if the ACCC:

(1) is of the opinion that:

(A) the disclosure of the information or the contents of the documents would not cause detriment to the *Transmission Network Owner* and/or *Transmission Network Service Provider* who supplied it; or

(B) although the disclosure of the information or the contents of the documents would cause detriment to the *Transmission Network Owner* and/or *Transmission Network Service Provider* who supplied it, the public benefit in disclosing it outweighs that detriment; and

(2) is of the opinion, in relation to any other person who has provided the *Transmission Network Owner* and/or *Transmission Network Service Provider* with information or documents that form part of the information or documents provided by the *Transmission Network Owner* and/or *Transmission Network Service Provider* to the *ACCC*, that:

(A) the disclosure of the information or the contents of the documents would not cause detriment to that person; or

(B) although the disclosure of the information or contents of the documents would cause detriment to that person, the public benefit in disclosing it outweighs the detriment,

and the procedures set out in clauses 6.2.6(d)-(f) have been followed.

(c) The *ACCC* must not publicly release any information or the contents of any documents under clause 6.2.6(b) until the expiration of 28 days from the date of receipt of a written notice sent by the *ACCC* to:

(1) the *Transmission Network Owner* and/or *Transmission Network Service Provider* who supplied the information or documents; or

(2) any person whom the ACCC is aware supplied the *Transmission Network Owner* and/or *Transmission Network Service Provider* with information or documents that form part of the information or documents provided to the *ACCC* by the *Transmission Network Owner* and/or *Transmission Network Service Provider*,

of the *ACCC*'s intention to disclose.

(d) The notice referred to in clause 6.2.6(c) must:

(1) state that the *ACCC* wishes to disclose the information or contents of the documents, specifying the nature of the intended disclosure and setting out detailed reasons why the *ACCC* wishes to make the disclosure;

(2) state that the *ACCC* is of the opinion required by clause 6.2.6(b) and setting out detailed reasons why it is of that opinion; and

(3) state that the *ACCC*'s decision to disclose the information or contents of the document can be reviewed under the *ADJR Act* upon application to the Federal Court.

(e) Where as a result of a review under the *ADJR Act* of its decision to publicly release information or documents the *ACCC* is not allowed to disclose particular information or documents provided to it for the purpose of performing its functions under the *Code*, the *ACCC* may nonetheless use the information or document for the purposes of performing its functions under the *Code*.

(f) Nothing in clauses 6.2.6(c) and (d) is intended to affect a *Code Participant's* rights to seek a review under general principles of administrative law of the *ACCC*'s decision to publicly release any information or the contents of any documents under clause 6.2.6(b).

The definitions in chapter 10 of the Code were supplemented whereby the *ADJR Act* is defined as "The Administrative Decisions (Judicial Review) Act 1977 (Cth)".

Similar code changes have also been made with respect to the powers of, and procedures to be followed by, the jurisdictional regulators in relation to the public release of information in the context of establishing revenue and/or price caps for distribution network owners (for more details see section 3.4.4).

3.2.5 The Commission's findings

The Commission believes that the access code's proposed regulatory regime broadly acts in the interests of NSP's, network users and the general public. While outcomes from the process cannot be guaranteed, this flexibility is necessary to ensure that transmission network prices periodically respond to changing circumstances. In coming to this conclusion, the Commission has placed significant reliance on the transmission pricing regulator's independence as well as the sanctions for non-compliance with the code and undertaking. Moreover, the regulator's access to relevant information in the required format is central to ensuring appropriately balanced pricing outcomes.

However, the Commission's draft decision on the NEM access code argued that the code's transmission pricing regime includes a number of deficiencies which will have to be rectified in order for the Commission to be satisfied that the code will effectively constrain the monopoly pricing tendencies of NSPs. The Commission believes that the applicant's code changes relating to the public release of regulatory information has met the Commission's concerns as outlined in the draft decision. The Commission has also accepted the applicant's undertaking to address, in the NECA review, the Commission's concerns over a number of the powers of the transmission network pricing regulator.

3.3 Transmission pricing methodology

The previous section (3.2) outlined the principles the regulator should apply when determining the overall revenue cap for a transmission network. In addition, the code proposes procedures whereby the regulator's overall revenue cap is translated into transmission network prices. The pricing methodology is flexible as it also provides considerable scope for the parties to negotiate network access prices.

3.3.1 What the applicant says

The applicant (sub. p. 60) stated that, in general, the fees for accessing a transmission network consist of:

- connection charges which will be determined through commercial negotiation, but should be directly related to the connection facilities requested; and

- maximum prices for using transmission facilities — ie transmission use of system (TUOS) charges.

The code proposes that NSPs must follow a three step procedure for deriving transmission network charges from the overall revenue cap established by the regulator, namely:

1. Allocate the overall revenue cap between regulated and contestable (non-regulated) services and between classes of network services (eg TUOS, entry and exit services).
2. Allocate the transmission network costs between the various classes of network services.
3. Recover the costs of the various network services through a series of usage prices.

This pricing methodology (for further details see Box 3.2) gives the NSP considerable flexibility to determine prices for individual services. Even more flexibility is introduced by allowing the NSP and the network users to negotiate price outcomes, for example:

- As the code's transmission pricing methodology establishes maximum prices for the revenue capped services, lower prices can be negotiated. Any such negotiated prices have to be agreed to by both parties but they do not have to be developed according to the code's proposed pricing formulae.
- The code's pricing formulae relate to standardised services (as defined in the code). Consequently, if a network user requires a service of a higher standard than prescribed in the code the price for such a service has to be negotiated by the relevant parties.

Box 3.2: Transmission network access pricing methodology

The price determination methodologies for the five classes of transmission network services can be summarised as follows.

1. **Entry services** — these are the services provided to *generators* at a single connection point;
   a) a generator's connection service charges may be specifically allocated in a contract;
   b) if not, a generator's entry service charges are recovered by:
      i) 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 which jointly provide entry and exit services);
      ii) a fixed annual charge;
2. **Exit services** — these are the services provided to transmission network *customers* at a single connection point;
   a) a customer's connection service charges may be specifically allocated in a contract;
   b) if not, a customer's exit service charges are recovered by
      i) 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);
      ii) a fixed annual charge;
3. **Transmission use of system services** — these are the services provided to either generators or customers which can be allocated on a locational basis;
   a) in a connection agreement, generators may consent to pay some of the use of system costs (if a dispute between a generator and an NSP arises the parties may seek recourse to the ACCC);
   b) 50 per cent of the use of system service costs are allocated to customer connection points;
      i) the revenue requirement is generated by cost reflective network prices;
      ii) the variable price is determined at the discretion of the NSP but must reflect the investment conditions in the network and may include any combination of: demand based charges; energy based charges; or fixed charge.
      iii) the charge may relate to either the actual (metered) use or an agreed use.
      iv) the demand based charge is to be calculated on a customer's maximum demand as averaged over a metered half hour period;

c) 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** — these are the services provided to *customers* which cannot be allocated on a location basis (eg services to maintain power system security);

   a) all of the revenue needed to provide such services is allocated to connection points and customers are charged on a postage stamp basis;

   b) 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** — relates to the risk premium for generators with connection agreements that include firm access compensation arrangements where the revenue is recovered from each generator (or any code participant) in accordance with the connection agreement.

Source: NGMC 1996, National Electricity Code.

However, an NSP's pricing discretion is not unlimited as a reallocation of costs between regulatory periods cannot increase a customer's TUOS charges by more than 2 per cent per annum over the average for that region.

The NSP may also require a network user to establish prudential requirements (eg capital contribution, pre-payment or financial guarantees), the terms of which are to be negotiated between the two parties. Moreover, where a transmission network service provider has to construct specific assets to provide connection or use of system services, the user may be required to make a capital contribution or pre-payment for all or part of the cost of the new assets. Any such contributions must be taken into account when determining that user's transmission service prices.

The applicant (sub. p. 249) argued that the interests of the transmission sector is protected through the regulatory regime's principles and objectives as discussed in section 3.3.

The public interest and that of network users is promoted through the non-discriminatory access to the transmission network. The applicant (sub. p. 251) added that while prices may differ, these differences will be justified either because of differences in the costs of using the network or because the demands placed on critical parts of the transmission system at different times.

The applicant (sub. pp. 250–1) argued that transmission pricing is cost reflective which is consistent with the COAG agreement. Moreover, cost reflectivity ensures that 'economic use is made of the existing network taking into account the long term costs of any augmentation necessary to meet continued growth.'

The applicant (sub. p. 163) claimed that other desirable features of the transmission pricing arrangements are that:

- energy markets will not be distorted as transmission pricing will reflect network use;
- hedging in the electricity market will be unaffected by transmission prices as they will be independent of a participant's contractual or spot market arrangements; and
- pricing arrangements will be transparent as transmission NSPs must publish their tariffs annually.

In summarising the transmission pricing regime, the applicant (sub. p. 60) concluded that as the prices will be published in advance and will reflect long run marginal costs, participants can assess their impact on the network and thereby make appropriate economic decisions.

3.3.2 What the participants say

In general, participants supported the broad thrust of the proposed approach to setting transmission prices. For instance, TransGrid (sub. p. 8) supported the network pricing arrangements and argued that prices 'should lead to appropriate decision making by participants' as they would: reflect efficient costs; be allocated to connection points; and be recovered through prices with a variable component thereby encouraging appropriate investment signals in the network or in alternatives (eg demand management).

The EUG (sub. p. 66) expressed its support for the code's adoption of a 'non-complex, relatively straightforward and transparent approach' to cost reflective network pricing.

However, despite this general support, a number of participants claimed the proposed pricing regime contained a number of serious deficiencies which needed to be rectified in order for the Commission to accept the access code. Principal amongst these concerns was that the pricing arrangements did not provide adequate locational signals to generators, in particular to co-generation vis a vis traditional coal fired technologies. As this issue also involves the code's distribution pricing arrangements, it is discussed in detail at the end of this chapter in section 3.7.

Apart from the locational signals, the other major concerns with the proposed transmission pricing regime were raised by the EUG and the BCA. As indicated above, while the EUG was supportive of cost reflective network pricing (CRNP), it was concerned that only 50 per cent of the TUOS charges would be collected in this manner, with the remainder being collected on a 'postage stamp' basis. The EUG (sub. p. 67) stated that:

> Users accept that some degree of averaging in TUOS charges is inevitable given the provision of 'common services' to network users and difficulty in apportioning some costs, but believe that the proposal to 'postage stamp' half of the TUOS charge appears quite arbitrary. It may lead to significant distortions in transmission use and also masks the provision of ancillary services by NEMMCO.

The EUG concluded that TUOS charges should either be a more precisely split between CRNPs and postage stamp prices, or that this should be part of the NECA review.

Concerns over the incentive effects of averaging network prices was also raised by Macquarie Generation (sub. p. 40) which argued that:

> Charges for network usage should not result in high costs for minimal usage of the system, such as load adjacent to a Power Station. Similarly new loads that will create only a marginal change in network energy transfer should not bear the full average costs of the entire network, but rather only the increased costs associated with the additional development.

A number of participants, including the BCA, BHP and Capral Aluminium, raised an additional concern that the proposed arrangements are penalising users with high load factors and high voltage needs. The BCA argued that in the past, published tariffs incorporated a reasonable reflection of the cost of taking power at various voltage levels — eg the Tariff H in Victoria provided customers with discounts of up to 17 per cent for electricity purchases from 66kV to 220kV. As a result, the BCA (sub. p. 23) argued that:

> Customers taking supply at EHV levels thus were shielded from bearing the cost of lower voltage transmission networks whose facilities they did not use and saw a reasonable reflection of the cost saving to a utility of taking power at a higher voltage level (and providing their own facilities).

However, the BCA argued that this 'distinction is now lost, and customers taking supply from the 'transmission system' all share a common and averaged pool of costs and are asked to pay the same transmission price.'

The EUG's concerns on transmission pricing also extends to connection charges which are to be negotiated as part of the connection agreements. The EUG (sub. p. 67) argued that while negotiation of such charges was the appropriate approach, the bargaining between transmission grid operators and end-users is quite uneven given the monopoly position of the former. The BCA (sub. p. 21) indicated that this monopoly position was already being used as NSPs:

> ... are taking a 'take it or leave it' attitude to network prices under the new regime and are generally refusing to negotiate.

The EUG (sub. p. 68) was particularly concerned in the context of negotiating prudential requirements for connection (eg capital contributions, pre-payments or financial guarantees). The EUG's concern was that the NSP could use these negotiations to frustrate connection. In the case of the connection charges and the prudential requirements, the EUG argued for establishing negotiation principles (such as those being developed by IPART) and clearer dispute resolution procedures.

3.3.3 The Commission's considerations

Traditionally electricity prices have been used to meet a number of objectives. As with any good or service, electricity prices are used to cover costs and to earn a return on the assets employed in the industry. They are also used to provide a signal to influence the pattern of demand and investment. Apart from these general efficiency objectives, electricity pricing has also been used to achieve a number of equity objectives. The most obvious example has been uniform pricing policies which involve cross-subsidising rural and remote communities at the expense of major urban areas. These cross-subsidies have usually been provided on the grounds of state development and to ensure that all sectors of the community have equal access to publicly provided services. However, it is generally recognised that attempting to achieve both efficiency and equity objectives through a single pricing policy involves a trade-off. An efficient pricing regime will generally have undesirable equity consequences while an equitable pricing regime will generally have undesirable efficiency consequences.

In recent times this trade-off has been well recognised, and some jurisdictions have moved to more efficient pricing structures and have attempted to meet equity objectives using other mechanisms not involving cross-subsidies. This change in the mood of governments is reflected in the access code's transmission pricing regime, whereby the code's transmission pricing objectives emphasise efficiency criteria. However, this does not mean that the code has been written in a way which ignores the equity concerns, nor does it mean that the Commission should disregard equity issues when assessing the proposed access code's transmission pricing regime.

An efficient pricing regime will generally reflect the interaction between an industry's costs and consumer demand. In the case of electricity, transmission networks are dominated by fixed capital costs. Moreover, as these assets are task and location specific they have a limited use in alternative activities, in particular those costs associated with planning and constructing network capacity. Therefore, once installed, many of the transmission assets can be viewed as being sunk.

An efficient pricing regime would have to recognise these various characteristics of transmission networks. In this respect, a nodal pricing regime received some support but was rejected in the early development of the NEC as being too complex. For example, in response to network constraints, such a regime could lead to widely fluctuating network prices both at different locations on the network and over time. Consequently, the regulator would be faced with a complex task of providing equitable outcomes for network users as well as preventing NSPs from exploiting their monopoly power in circumstances where profits and losses would vary from year to year.

As indicated in the previous section, the over-riding objective of the transmission pricing regime has been to ensure that NSPs can consistently earn a reasonable rate of return and that electricity consumers are protected against exploitation by monopoly NSPs. As a result, transmission prices are based on a cost of service model which emphasises cost allocation principles rather than balancing demand with available capacity.

The inevitable consequence of this emphasis is that it down plays the interaction between an industry's costs and consumer demand so that pricing signals for using transmission networks will be blunted, particularly in the short run. As a result, network pricing signals will not be encouraging an increased use of transmission assets with excess capacity, nor will they be used to ration demand where network constraints exist. However, the code is not silent on these issues as incentives to balance demand and supply are contained in the broader NEC. For instance, the wholesale electricity market arrangements include a proposal to auction capacity on inter-regional constraints. While the exact nature of these auction contracts has yet to be finalised, this addition to the wholesale market arrangements ensures that the network pricing regime is responsive to demand characteristics.

The advantage of this approach is that the revenue raised from auctioning inter-regional constraints does not accrue to the NSP. Rather it is separately collected and returned annually to the NSP which is required to pass it on to its customers. Consequently, the NSP would receive no benefit by acting like a monopolist by 'sitting on' an inter-regional constraint. Despite these advantages, by only operating between regions, this arrangement falls well short of a full nodal pricing regime. As a result the access code relies on a number of supplementary arrangements to manage constraints within regions (ie global planning and payments to embedded generators for avoided network augmentations).

In order to recover transmission network costs, the access code identifies five separate transmission services, namely: entry services for generators; exit services for transmission customers; common services; transmission use of system services for allocatable costs; and services to generators with firm access arrangements. The costs recovery and pricing regime for each of these services is addressed in turn.

Entry and exit services

The code adopts a strict or 'shallow' definition of entry and exit assets thereby avoiding complex analysis to determine the sharing of any common assets between users. Nevertheless, radial transmission lines for generators but owned by the NSP will be treated as connection assets as will some station establishment and building costs.

To the extent that connection assets, whether they are for entry or exit services, are fixed costs linked to meet a customer's demand requirements, a fixed annual charge will yield an economically efficient outcome. Moreover, as the required connection assets will differ on a case-by-case basis, it is reasonable that the charges for the assets are also determined on a case-by-case basis — in particular, as the NSP is restricted to only earning a reasonable rate of return on assets at an individual connection point. To the extent that an NSP is obliged to process connection applications, it is also reasonable for the NSP to impose up-front charges and prudential requirements to cover themselves for installing any connection specific assets. Otherwise, the NSP would be vulnerable to incurring losses in the event of an unforseen or premature disconnection.

Common services

Although consumers will be connected to different parts of the network, many will receive their electricity through shared facilities (eg dynamic and static reactive plant). In the case of common transmission network facilities, the code's approach is to allocate the required revenue on a postage stamp basis and to recover this through the common services charge which is levied on the basis of the quantity of energy consumed.

Economic theory does not provide a definitive rule about efficient mechanisms for recovering common costs other than it should be performed in a way which minimises distortions in consumption patterns. For example, an efficient cost recovery mechanism could involve price discrimination whereby price sensitive customers are charged a relatively low price but price insensitive customers are charged a relatively high price. However, in practice it has been more common to use administratively simple and equitable rules to allocate the common costs of shared facilities between customer classes.

On this basis, the transmission network common services charge may not be the most efficient approach available. However, the code's approach is pragmatic. The transmission common services charge is both administratively simple and a relatively equitable mechanism for recovering transmission network common service costs.

Transmission use of system services

The recovery of the costs of providing TUOS services is a complicated formula which allocates the revenue requirement on both a cost reflective and postage stamp basis. These revenue requirements can be allocated between customers on the basis of fixed, demand or energy related charges.

To the extent that the CRNP component reflects assets used, the TUOS charges are cost reflective. However, as TUOS costs are also allocated on a postage stamp basis, they will not be cost reflective for every consumer. TUOS charges will only be cost reflective on average as the NSP can only earn a normal rate of return on TUOS assets.

In part this reflects network characteristics that many facilities are shared and cannot be attributed to particular users. Moreover, some degree of averaging costs amongst users is inevitable in the supply of any good or service. In these cases, the benefits of having fully cost reflective prices is outweighed by the administrative complexity of having finely tuned prices. However, as the postage stamp allocation occurs across a complete transmission network, it is also likely to retain some cross-subsidies from major metropolitan centres to the rural and remote communities.

The access code and the application asserted that empirical studies indicated that the proposed balance between the CRNP and postage stamp cost allocations provides approximately correct locational signals. However, participants questioned whether the current balance between CRNP and postage stamp cost allocations was efficient. This issue is also closely linked to the incidence of the TUOS charges which cogenerators have argued represents a major disincentive to the entry and competitiveness of embedded generation.

While the incidence of TUOS charges is addressed more fully in section 6.7, it is evident that uncertainty surrounding the efficiency of the TUOS charges is linked to how well they reflect underlying costs. Based on the evidence presented, the Commission is not in a position to be definitive on the efficiency or otherwise of the proposed TUOS charges. Consequently, in the draft decision, the Commission stated:

> **The Commission believes that NECA's review of the transmission pricing regime should re-examine and justify the appropriate balance between the CRNP and postage stamp allocation of costs for TUOS charges.**

In developing the proposed structure of TUOS charges, it is evident that the code's authors have had to make a number of compromises. In part, this is because not all network costs can be attributed to individual customers. Moreover, to the extent that the postage stamp methodology includes cross-subsidies, this approach avoids the likelihood of a price shock and the possibility of depressing economic conditions in rural and remote communities. It also avoids the transmission network owners facing a significant decline in their revenue earning ability and therefore the underlying value of their asset base.

These compromises will adversely affect the likely efficiency of the proposed TUOS charges. Consequently, the presence of shared facilities and the inclusion of cross subsidies on the transmission network makes it difficult to release customers from an obligation to contribute to TUOS assets. For instance, it would appear to be inequitable if some customers (eg embedded generators) in metropolitan regions could avoid contributing to the cross-subsidies yet others are still required to contribute to the cross-subsidies. Indeed, if large contestable electricity consumers can avoid contributing to cross-subsidies, an increased burden will be placed on those customers which are unable to avoid paying the TUOS charges. However, the Commission is unclear on the extent of this problem as the relative size of the various components of TUOS charges are unknown. Consequently, in its draft decision the Commission argued that the NECA review of transmission pricing should examine the extent of any cross-subsidies involved in TUOS pricing. In particular, the Commission stated:

> **The Commission believes that NECA's review of the transmission pricing regime should identify the extent of any cross subsidies in the postage stamp component of the TUOS charges.**

In addition, participants also expressed concerns that transmission prices will not reflect the costs and needs of customers with high load factors and high voltage demands. In part, this concern is again related to the averaging of TUOS costs and the resultant move away from cost reflective prices. For instance, TUOS charges will reflect the assets and costs involved in supplying high voltage demands to the extent that transmission charges in general will be cost reflective. While the code specifically allows voltage based price discrimination for distribution prices, the code is silent on this for transmission prices. Clearly, the code's silence on this issue does not prohibit the levying of discounts for high voltage transmission customers. Rather, the code relies upon negotiation and that prices, on average, will be cost reflective.

Finding an appropriate balance between efficiency objectives and equity concerns is a fundamental part of designing and implementing any reform package. However, the Commission is concerned that the presence of cross-subsidies in TUOS charges may significantly detract from the likely benefits from the NEM. This concern is supported by a large number of users which have provided submissions to this review. Consequently, the Commission urges jurisdictional governments to adopt more cost reflective allocation of TUOS costs. In order to ensure that the benefits of reform are spread across the whole community, jurisdictional governments could seek to achieve equity objectives, not by postage stamping costs and blunting efficiency incentives, but through other more efficient mechanisms such as contracts to pay transmission NSPs to subsidise the provision networks in rural and remote communities (see Box 3.3 for more details).

The efficiency impacts of the TUOS charges are not solely related to the cost reflectivity of their allocation between transmission customers. The form of the price signal also influences consumers' demand for using the assets. In general, transmission networks are dominated by fixed costs where the consumption (or depreciation) of the assets and other non-capital costs are not particularly related to the amount of electricity transported. Consequently, the marginal costs of using an unconstrained network are likely to be very low.

Reflecting this, the code provides for the CRNP component of the TUOS charges to be recovered through a combination of fixed, demand and energy related charges. Moreover, the code requires NSPs to adopt pricing structures which reflects the network's investment conditions (ie long run marginal costs). Therefore, to the extent that transmission NSPs opt for a pricing regime which emphasises access charges related to peak demand with a lesser reliance placed on energy related charges (ie a two part tariff) the price mechanism will be efficient. However, there is no guarantee that an NSP will establish an efficient structure of prices.

Box 3.3: Overview of CSO policies, practices and alternatives

Traditionally CSOs have been provided by GBEs employing uniform pricing policies involving cross-subsidies between differing classes or groups of consumers. This approach has tended to distort consumption, production and investment decisions. Providing CSOs through cross-subsidies has also usually required governments to maintain GBEs as the monopoly supplier which has limited competition and further detracted from dynamic efficiency gains.

The Industry Commission (1997) recently summarised the current approach to handling CSOs by noting that all governments now have initiated programs to review CSO policies as part of broader GBE reform. The IC found that significant changes have been made:

- Australian governments have adopted a commonly agreed definition of CSOs;
- several governments have established programs to identify CSOs systematically;
- in principle, most governments accept that CSOs should be costed at avoidable cost and should be funded directly from consolidated revenue;
- several CSOs are now provided under contract, in some cases by private sector firms; and
- some jurisdictions have adopted, or are in the process of adopting, programs for monitoring their CSOs.

In a paper on infrastructure pricing, the BIE (1995) advocated a number of alternative more transparent and sometimes less distorting mechanisms of delivering CSOs. For example, by establishing contracts which directly fund enterprises to provide subsidised services to the targeted communities. This approach makes the extent of the subsidy transparent and avoids the distortions created by having to charge higher prices to other users. This approach also allows competition to be introduced by putting the delivery of additional services in the targeted communities up for competitive tender (ie additional capacity could be provided either through network augmentation, embedded generation or demand side options). Other alternatives canvassed in the BIE paper include levies on users, direct cash payments to targeted users and accepting lower rates of return.

Source: Industry Commission 1997, *Community Service Obligations: Policies and Practices of Australian Governments*, Information Paper, AGPS, Canberra, February.

Bureau of Industry Economics 1995, *Issues in Infrastructure Pricing*, AGPS, Canberra, August.

As a result, the Commission has argued in the past, and reiterated this view in its draft decision, that the transmission pricing regulator should have powers to approve an NSP's pricing structure, similar to those held by the jurisdictional regulators with respect to distribution prices. Specifically, the Commission stated that:

> **The Commission believes that the transmission pricing regulator should have powers to approve an NSP's pricing structure, similar to those held by the jurisdictional regulators with respect to distribution prices.**

The pricing methodology for the postage stamp element of the TUOS charges is the same as for common services. Consequently, the prices to recover the postage stamp component of TUOS charges may not be the most efficient approach available, but it is both administratively simple and a relatively equitable.

3.3.4 The applicant's response

The applicant accepted the Commission's recommendations in the draft decision and indicated that the appropriateness of the balance between cost reflective and postage stamp pricing and an examination of the extent of any cross subsidies in the postage stamp element of TUOS charges will be examined as part of NECA's review of transmission network pricing. In addition, the applicant indicated that the NECA review will also address the Commission's request that the code be amended so the transmission pricing regulator would have similar powers as the distribution pricing regulators with respect to the power to approve a transmission NSP's pricing structure.

Specifically, these issues are addressed in item 5 of NECA's Terms of Reference for its Transmission and Distribution Pricing Review which states, amongst other matters, that the review will consider:

- the locational signals resulting from the transmission and distribution pricing regimes, including the appropriate balance between cost reflective and postage stamp elements of charges and the incidence and treatment of cross subsidies; and
- the appropriate powers of transmission and distribution regulators in particular in relation to the development and monitoring of service charters drawn up by transmission network service providers.

3.3.5 The Commission's findings

The proposed transmission pricing regime involves a number of compromises between efficiency and equity concerns as well as between desirable and practical considerations. Consequently, it is evident that such a pricing regime will not completely satisfy the competing needs of all of the relevant parties.

Nevertheless, the Commission believes the code acts to promote the interests of network service providers, network users and the wider community:

- by allowing entry and exit service costs to be negotiated on a case by case basis;
- by allowing the network service provider to earn a reasonable rate of return on the costs of providing entry and exit services through fixed annual charges;
- by using an administratively simple and relatively equitable mechanism for recovering transmission network common service costs, including their allocation on a postage stamp basis;
- by ensuring that network service providers can earn no more than a reasonable rate of return on transmission use of system services; and
- by providing the network service providers with an opportunity to use a combination of relatively efficient and equitable prices to recover the allocated costs of providing transmission use of system services.

The code acts to promote the interests of the wider community by avoiding cost allocation procedures for transmission use of system services which may otherwise have resulted in substantial price rises for electricity users in rural and remote communities.

However, the Commission is not convinced that the cost allocation provisions for transmission use of system services are efficient and that this deficiency will significantly reduce the long term benefits of the electricity access code. The Commission accepts the applicant's undertaking to re-examine these issues as part of the NECA review of the transmission pricing regime.

This also provides an opportunity for jurisdictional governments to clearly identify their policies towards any cross-subsidies which may be included in the TUOS charges. As any such cross-subsidies have the potential to significantly reduce the benefits which derive from the NEM, the jurisdictional governments should also develop longer term strategies for removing them from the transmission network pricing regime and replacing them with alternative policies.

Part B Distribution

3.4 Regulatory regime for distribution pricing

3.4.1 What the applicant says

The regulatory regime for distribution revenues and prices is similar to the proposed regime for transmission revenues. For instance, the applicant (sub. p. 253) argued that the code's approach to distribution pricing allows NSPs 'to develop innovative pricing solutions within a 'light handed' regulatory oversight of monopoly network activities.' Moreover, the proposed distribution pricing regime also consists of a number of objectives and principles for determining maximum network revenues and/or prices (for more details see Box 3.4). However, the applicant (sub. p. 60) stated that the proposed distribution pricing regime allows for a much greater level of averaging by voltage level and geographic location. In addition, rather than simply setting a revenue cap, a distribution NSP's charges will be controlled on two levels:

a) on the overall revenue or average price for network services; and
b) on the individual tariffs applied to individuals or groups of customers.

Regulation of distribution network pricing will be the responsibility of the relevant state or territory regulator, although these duties can be passed over to the ACCC. As with other parts of the code, these regulators will perform their distribution pricing functions in accordance with the transitional arrangements determined by the jurisdictional derogations and access regimes (for details of the distribution pricing derogations see Table 3.2).

Box 3.4: Overview of distribution pricing objectives and principles

The code establishes, amongst other things, that:

1. the regulatory regime must seek to achieve outcomes which:
   a) are efficient and cost effective;
   b) are incentive based and provide a reasonable rate of return (without monopoly rents) to network owners;
   c) foster efficient investment, operation and use of network assets;
   d) recognise pre-existing government policies on asset values, revenue paths and prices;
   e) promote competition; and
   f) are reasonably accountable, transparent and consistent over time;
2. the regulation of a revenue and/or a price cap for distribution services must:
   a) be consistent with the regulatory objectives (see 1 above);
   b) address monopoly pricing concerns primarily through the competitive supply of network services but otherwise through an explicit revenue or price cap;
   c) promote efficiency gains and a reasonable balance between supply and demand side options;
   d) promote a reasonable rate of return to network owners on an efficient asset base where the value of:
      i) new assets are consistent with take-or-pay contracts;
      ii) existing assets are determined by jurisdictional regulators or are consistent with the jurisdictional regulatory asset base;
      iii) revalued assets, undertaken by the jurisdictional regulator, are consistent with COAG decisions;
3. the form and mechanisms of economic regulation must:
   a) be specified by the jurisdictional regulator to be a CPI–X price and/or revenue cap, or an incentive based variant, for each network owner;
   b) have a regulatory control period of at least 3 years;
   c) take into account expected demand growth, service standards, price stability, potential efficiency gains, cost of capital, risk, on-going commercial viability and changes in energy losses;
   d) when establishing the revenue requirement and/or price cap:
      i) take into account growth in the demand for, and costs of, the distribution service;
      ii) allow for the correction in later years for any over or under recovery of revenues;
4. distribution NSPs must provide the jurisdictional regulator with annual financial statements, indicating economic performance and asset values, so the regulator can monitor compliance with the regulatory caps and determine caps in future periods;

Source: NGMC 1996, National Electricity Code.

Table 3.2: Derogations for regulatory regime for distribution pricing

State	Expiry date	Details
Victoria	31/12/2000	• transitional distribution pricing arrangements will be regulated by the EI Act, ORG Act and the Tariff Order;
	indefinite	• national guidelines and regulatory regime for distribution pricing must be consistent with clause 5.10 of the Tariff Order;
New South Wales	1/1/2001	• transitional distribution pricing arrangements will be regulated by the IPART Act and any subsequent IPART determinations;
ACT	31/12/2000	• transitional distribution pricing arrangements will be regulated under the ACT Energy and Water Act;
South Australia	31/12/2000	• transitional distribution pricing arrangements will be governed by the code's general principles but according to criteria and methodologies determined by the South Australian Government.
Queensland	18/12/2000	• transitional distribution pricing arrangements will be regulated under the Electricity Act and the QCA Act;

In general, the code sets out principles which *may* be applied:

- to the economic regulation of distribution service pricing; and
- to the formulation of national guidelines.

Any national guidelines for the regulation of distribution pricing can only be developed with the consent of each participating jurisdiction and must not duplicate, or be inconsistent with, features of the jurisdictional regulatory regime. The code does not require jurisdictional guidelines for the regulation of distribution pricing. However, if such guidelines exist, they must not be inconsistent with the code's principles and they must not be inconsistent with any national guidelines.

Even though the code provides for national guidelines, the applicant (sub. p. 252) argued that distribution pricing is specific to a distribution region and there is 'no economic benefit in the rigid application of a prescriptive national regime.' Despite the potentially diverse approaches to distribution pricing in the national electricity market, the applicant (sub. p. 252) anticipates that:

> To the extent that distribution networks have common characteristics and cost drivers, the regulation in each jurisdiction are likely to be similar. However, where different cost drivers or different industry characteristics exist, specific Network Service Provider regulation may evolve.

The applicant (sub. p. 253) justified the need for jurisdictional regulators on the basis that they are required to take account of state based distribution pricing issues, in particular:

- the existing arrangements (ie long term transitional arrangements to avoid price shocks and the privatisation of some distributors); and
- the jurisdictionally determined customer service standards and supply quality requirements.

The applicant (sub. p. 253) concluded that:

> ... there is no loss of economic efficiency associated with having jurisdictional regulators of network prices for distribution services, provided that those regulators operate to a common set of principles and prices are presented to customers in a similar form. Given the monopoly nature of distribution networks, the fact that prices are calculated under different regimes on either side of a jurisdictional border is considered to be highly unlikely to have any impact on competition.

Consistent with the approach adopted for transmission pricing, the code provides for a NECA review of the pricing methodologies and principles applying to distribution networks. The review will examine the net benefit of modifying the proposed pricing regime in light of relevant international experience and will be completed by 1 January 1999.

In commenting on the benefits of the proposed distribution pricing regime, the applicant (sub. p. 253) argued that the published tariffs serve two functions. First, they provide a clear and simple access regime for all customers. Second, they establish maximum prices which facilitates commercially driven tariff negotiations. In addition, the objectives of the pricing regime's incentive arrangements are to improve efficiency and performance by encouraging profit maximisation.

3.4.2 What the participants say

Many of the participants' comments on the proposed distribution pricing regime mirrored their views on transmission pricing. For instance, the EUG's concerns relating to the deprival approach to asset valuation, achieving internationally competitive prices and preferring an alternative incentive mechanism are also applicable to the proposed distribution pricing regime.

Apart from these more general concerns, the EUG (sub. p. 70) indicated that their major additional concern about distribution pricing is the 'considerable scope for jurisdictional inconsistencies' as a result of price averaging associated with cross-subsidies and asset issues. The EUG agreed that the code should avoid rigid or prescriptive regulatory regimes. Nevertheless the EUG (sub. p. 71) supported a national approach including either having a single regulator or, if that was not possible, ensuring that the jurisdictional regulators have 'independent charters and transparent processes, as in New South Wales and Victoria.'

Moreover, while generally supportive of the access arrangements, BHP (sub. pp. 1–2) expressed concerns that distribution use of system pricing could undermine the benefits of competition and:

> ... the structure of electricity charges might distort choices between buying electricity from distributors and generators and building new generation capacity for our own use.

3.4.3 The Commission's considerations

The proposed regulatory regime for distribution pricing is conceptually the same as that which applies to transmission pricing. The views expressed by the applicant and participants on the distribution pricing regime were generally consistent with the arguments presented on the transmission pricing regime. Consequently, the Commission's assessment of the beneficial and detrimental aspects of the distribution pricing regime are consistent with the comments in section 3.2.3.

Despite the consistencies in the regulatory frameworks, the importance of ensuring both efficient and equitable distribution prices is accentuated by its economic significance and complexity. For instance, distribution prices represent around 25 per cent of the delivered price of electricity in contrast to transmission's 9 per cent. Moreover, the integrated nature of the networks means that a larger proportion of the facilities will be shared between groups of customers. Consequently, it could be expected that distribution prices may reflect a high degree of cost averaging. Alternatively, the diversity in the demand for electricity at the retail level provides distribution networks with a greater opportunity to differentiate prices on the basis of voltage levels and load classes.

To address these concerns, the NEM's distribution pricing regime is based on a set of principles and objectives which attempt to reflect the competing needs of NSPs, network users and the wider Australian community. Jurisdictional regulators will undertake periodic reviews to determine revenue and/or price caps. The proposed regime has the flexibility to allow distribution prices to vary, with the agreement of the jurisdictional regulator, depending on location, voltage level and load profile. The distribution NSP is encouraged to operate efficiently through a CPI–X incentive mechanism. Moreover, the code requires the jurisdictional regulators to assess the revenue and/or price caps on the basis of efficient operating and maintenance costs and on an asset base which is capped at the deprival value. This asset valuation methodology allows the regulator to choose a current cost valuation but also allows it to 'strand' assets which are in excess of forecast needs or which have been 'gold plated'.

The Commission accepts the applicant's broad arguments that the NEM access code's pricing principles for distribution networks contain many aspects which act to protect the legitimate business interests of NSPs, access seekers and the public more generally. Of particular significance is that the access code:

- acts to protect the interests of the facility owner by requiring the jurisdictional regulator to provide NSPs with a revenue which is sufficient to recover efficient costs and earn a reasonable return on efficient investments;
- acts to protect the interests of network users and the public by depriving NSPs of the power to unilaterally exploit monopoly power by establishing a price regime to be administered the jurisdictional regulator;
- acts to protect the interests of NSPs, network users and the public by including incentive mechanisms which encourage NSPs to continually improve productivity and to share the benefits between their shareholders and network users; and
- acts to protect the interests of NSPs, network users and the public by providing the jurisdictional regulator with the flexibility to periodically reassess the determinants of network prices (ie every 3 years) and, in doing so, to respond to changing circumstances.

However, the flexibility inherent in these arrangements involves a trade-off as there can be no guarantee of the outcomes of the distribution price regulatory processes. Without limiting the flexibility of jurisdictional regulators, the concerns of participants that the distribution pricing regime will not generate internationally competitive electricity prices depends on the effectiveness of the jurisdictional regulator.

As with the transmission regulatory regime, the performance of the jurisdictional regulator and the regulatory process depends on a combination of factors including: transparent, impartial and accountable decision making; access to relevant information; adequate resourcing; and effective sanctions for non-compliance with the code requirements or with regulatory directions.

In this context, the Commission believes that it will be important for the jurisdictional regulators to be independent and at arms length from the other policy development processes of government. By doing so, the regulator will be seen to be an independent umpire capable of making decisions in the public interest and without a vested interest in the outcome.

Of particular concern to the Commission is that without an independent regulator, the price regulatory process may be used to justify and disguise the charging of monopoly prices which are returned to governments in the guise of excessively large stream of dividend payments. Similarly, the Commission is also concerned that the risks of inappropriately determining the parameters for distribution pricing will be heightened if regulators are required to juggle a number of competing duties including their regulatory roles *vis a vis* issues of state development, infrastructure ownership and public utility dividend policies.

Clearly, these are all legitimate objectives of government. However, the regulatory outcomes are likely to suffer if electricity price regulation becomes a mechanism for implicitly implementing other government policies. Indeed, it is possible that the benefits of introducing increased competitive pressures into the electricity supply industry may be limited if governments attempt to cling to traditional mechanisms of delivering policy objectives. Rather, the Commission would prefer governments to use more transparent mechanisms to achieve a range of objectives such as ensuring the integrity of jurisdictional budgets and ensuring all residents gain a share in the benefits of reform.

To reduce the likelihood, and perception, that the electricity pricing regime will be used to inflate access prices, in its draft decision, the Commission argued that in order to accept the access code the Commission would have to be satisfied that the jurisdictional regulators are statutorily independent of government. Preferably, the code should explicitly require jurisdictional regulators to be independent bodies. Specifically, the Commission stated that:

> **The Commission believes the access code must explicitly require the jurisdictional regulators to be statutorily independent of executive government by the commencement of the NEM's network pricing regimes in 1999.**

In addition to these concerns, it will also be important for regulators to demonstrate their independence in making decisions which can have a significant material impact on network service providers, network users and others in the community. Otherwise, it is likely that a regulator's price setting processes will be protracted and expensive and therefore move away from the 'light handed' regulation as envisaged by the access code.

Moreover, to ensure that the regulatory decision making processes are accountable, the Commission believes that the decisions of the regulators should be appealable. Currently such appeal rights already exist with a number of the jurisdictional regulators. Unnecessarily protracted decision making processes may result if the grounds for the appeal goes to the merit of a regulator's decisions. To avoid this, yet to introduce accountable decision making processes, it may be sufficient to allow appeals on the basis of issues such as natural justice and the application of administrative law principles.

The Commission also places considerable weight on those code provisions which provide the jurisdictional regulator with the necessary powers to: determine the form in which an NSP will submit their annual financial statements; and verify or independently audit the information sought. Non-compliance with these requirements may result in both a breach of an NSP's access undertaking as well as a breach of the NEC.

In assessing the powers of the transmission regulator, the Commission identified a number of short comings which also limit the powers of the distribution regulator. First, while it may be included in the jurisdictional regulator's empowering act, the access code does not separately provide the jurisdictional regulator with the power to specify a date by which certified annual financial statements or requested information is to be provided by the NSP. This oversight may result in an unreasonable delay in the NSP providing required and requested information to the regulator. If this was to occur, the distribution price setting processes and enforcement procedures may become ineffective.

Second, in the context of the transmission regulatory regime, the Commission sought and achieved changes to the code to remove an NSP's effective power of veto over the release of information provided in the context of the rate reviews. In its draft decision, the Commission also expressed its concerns that the code may provide distribution NSPs with a similar power of veto. However, in its draft decision the Commission did not actively seek a code change as the code already provided scope for jurisdictional laws to allow regulators to release confidential information.

In addition to these deficiencies, there are a number of inconsistencies between the powers of the transmission and distribution regulators which further constrain the powers of the distribution regulator and brings into question the likely effectiveness of the distribution regulatory regime.

First, the transmission regulator can seek both certified annual financial statements and any other information the ACCC reasonably requires to perform its regulatory function. In contrast, the distribution regulator can only seek annual financial statements.

Second, the transmission regulator can seek information from both the transmission network owner and/or transmission network service provider. In contrast, the distribution regulator can only seek information from the distribution network owner. This may unduly restrict the regulator in circumstances where there is a distinction between the distribution network owner and service provider.

Third, the annual statements of the transmitter must provide a true and fair statement of the financial and operating performance in a form determined by the ACCC. In contrast, the distributors are required to provide a true and fair statement of their economic performance and the value of their assets in any reasonable form determined by the distribution regulator. The impact of these differences are unclear, but they may well restrict the effectiveness of the distribution regulator when they come to impose price and/or revenue caps.

Fourth, the transmission regulator can use the information to assess the allocation of costs and identify cross subsidies. In contrast, the distribution regulators do not have this power and some of its other powers are worded differently. In both circumstances it is unclear why these limitations apply.

As a result of these concerns, in its draft decision, the Commission stated:

> **The Commission believes that NECA's review of the distribution pricing regime should review the powers of the distribution regulator, in particular in respect of:**
>
> **a) being able to request data other than annual financial statements;**
>
> **b) being able to specify reporting dates;**
>
> **c) being able to request information from only the distribution network owner;**
>
> **d) the limitations on which the regulator can use the information; and**
>
> **e) the limitations on which the form in which the regulator can seek information.**

3.4.4 The applicant's response

Discussions with the applicant and the jurisdictions indicated that they were unwilling to insert into the code a requirement that the jurisdictional regulators be statutorily independent of government. It was argued that the level of independence of jurisdictional regulators is a matter of state government policy which must be kept separate from the code which is an instrument for defining rules for the participants in the NEM.

However, the applicant noted that the jurisdictional regulators in New South Wales (and the Australian Capital Territory) and Victoria are already statutorily independent. Moreover, Queensland has established the Queensland Competition Authority as a separate regulatory authority in that state. The South Australian government indicated that it is presently implementing a series of reforms that will establish network pricing arrangements with a level of regulatory independence to ensure the effective operation of the NEM. These arrangements will consist of, in the short term, an electricity pricing order:

- setting distribution and transmission prices until 30 June 1999; and
- defining regulatory principles until 2002 — the end of South Australia's network pricing derogations.

The pricing order is currently being reviewed by an independent consultant to ensure it is consistent with the code's regulatory principles. In addition, South Australia's arrangements will also provide for a pricing regulator with powers to set maximum prices. Initially, the pricing regulator will be the relevant Minister, although this could also be an independent regulator. The South Australian government indicated it will review these arrangements within the next twelve months and noted that it has already committed to establishing an independent regulator for gas distribution pipelines.

In response to the Commission's concerns about the powers of the distribution pricing regulators, the applicant accepted the Commission's recommendation. In addition, the applicant also addressed the Commission's concerns over a distribution network owner's effective power of veto over the release of information provided in the context of rate reviews. In particular, clause 6.10.6 and 6.10.7 have been amended to state that:

6.10.6 Monitoring of Distribution Network Owner and/or Distribution Network Service Provider (as appropriate) performance and compliance with regulatory determinations

(a) The *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) must use reasonable endeavours to ensure that it complies with ~~the~~ any regulatory cap in respect of *distribution services* in any year.

(b) The *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) must submit certified annual financial statements to the *Jurisdictional Regulator* (in ~~any reasonable~~ a form and by a date ~~which may~~ to be determined by the *Jurisdictional Regulator*) which provide a true and fair statement of the financial and operating performance of the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) in a reporting period.~~:~~

~~(1) the economic performance of the *Distribution Network Owner* in a reporting period; and~~

~~(2) the value of the *distribution network* assets and *connection assets* for the purpose of determining the *distribution service* prices.~~

(c) The certified annual financial statements submitted by the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) to the *Jurisdictional Regulator* may be used by the *Jurisdictional Regulator* to:

(1) monitor the compliance of the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) with the *regulatory caps*; ~~and~~

(2) assess the allocation of costs between services which are subject to regulation under the *regulatory caps* and services or activities which are not subject to regulation under the *regulatory caps*, and to identify any cross-subsidy between these different types of services or activities; and

(3) collate data regarding the financial, economic and operational performance of the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) to be used as input by the *Jurisdictional Regulator's* decision-making regarding the setting ~~in respect of the determination~~ of *regulatory caps* or the regulatory controls to apply in future *regulatory control periods*.

(d) In addition to the certified financial statements referred to in clauses 6.10.6(b) the *Jurisdictional Regulator* may require a *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) to provide any other information the *Jurisdictional Regulator* reasonably requires to perform its regulatory functions in a manner and by a date it considers to be consistent with the requirements of clauses 6.10.2, 6. 10.3, 6. 10.4 and 6. 10.5.

(e) The *Jurisdictional Regulator* may request or undertake verification and/or independent audit of any information sought by it, or provided to it under this clause 6.10.6.

(f) Information provided to the *Jurisdictional Regulator* by a *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) pursuant to this clause~~s~~ 6.10.6 ~~and 6.10.7~~ must be treated as confidential by the *Jurisdictional Regulator* and must not be disclosed to any other party without the prior written consent of the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) which provided the information unless the procedures set out in clause 6.10.7(c)-(e) have been followed. ~~except in accordance with legislation governing the treatment of confidential information applicable to the *Jurisdictional Regulator* in the relevant *participating jurisdiction*~~

6.10.7 Information disclosure by the Jurisdictional Regulator

~~(a) This clause 6.10.7 is subject to clause 6.10.6(e).~~

(a) In making a determination or any other decision under this clause 6.10, the *Jurisdictional Regulator* must publish full and reasonable details of the basis and rationale of ~~its~~ the decision ~~and the information to be disclosed publicly by the *Jurisdictional Regulator* is to include,~~ including but not ~~be~~ limited to the following:

(1) reasonable details of qualitative and quantitative methodologies applied including any calculations and formulae; and

(2) full reasons for all material judgments and qualitative decisions made and options considered and all discretions exercised which have a material bearing on the outcome of the *Jurisdictional Regulator's* decision;

(b) Notwithstanding clause 6.10.7(a), the *Jurisdictional Regulator* must also disclose relevant information to the relevant *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) only on request by the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) and such information is to include, but not be limited to the following:

(1) the values adopted by the *Jurisdictional Regulator* for each of the input variables in any calculation and formulae, including a full description of the rationale for adoption of those values; and

(2) full and reasonable details of other assumptions made by the *Jurisdictional Regulator* in the conduct of all material qualitative and quantitative analyses undertaken in relation to the setting of a regulatory cap or related manner.

(c) Each *Jurisdictional Regulator* in discharging its functions under the *Code* may publicly release information or the contents of documents provided to it by a *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) for the purposes of performing its functions under the *Code* in circumstances where the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) has declined to give written consent to its release in accordance with clause 6.10.6(f) if the *Jurisdictional Regulator*:

(1) is of the opinion that:

(A) the disclosure of the information or the contents of the documents would not cause detriment to the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) who supplied it; or

(B) although the disclosure of the information or the contents of the documents would cause detriment to the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) who supplied it, the public benefit in disclosing it outweighs that detriment; and

(2) is of the opinion, in relation to any other person who has provided the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) with information or documents that form part of the information or documents provided by the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) to the *Jurisdictional Regulator*, that:

(A) the disclosure of the information or the contents of the documents would not cause detriment to that person; or

(B) although the disclosure of the information or contents of the documents would cause detriment to that person, the public benefit in disclosing it outweighs the detriment,

and the procedures set out in clauses 6.10.7(c)-(e) have been followed.

(d) The *Jurisdictional Regulator* must not publicly release any information or the contents of any documents under clause 6.10.7(c) until the expiration of 28 days from the date of receipt of a written notice sent by the *Jurisdictional Regulator* to:

(1) the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) who supplied the information or documents; or

(2) any person whom the *Jurisdictional Regulator* is aware supplied the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate) with information or documents that form part of the information or documents provided to the *Jurisdictional Regulator* by the *Distribution Network Owner* and/or *Distribution Network Service Provider* (as appropriate),

of the *Jurisdictional Regulator*'s intention to disclose.

(e) The notice referred to in clause 6.10.7(d) must:

(1) state that the *Jurisdictional Regulator* wishes to disclose the information or contents of the documents, specifying the nature of the intended disclosure and setting out detailed reasons why the *Jurisdictional Regulator* wishes to make the disclosure;

(2) state that the *Jurisdictional Regulator* is of the opinion required by clause 6.10.7(c) and setting out detailed reasons why it is of that opinion; and

(3) identify the legislation (if any) governing the review of decisions by the *Jurisdictional Regulator* to release information in the relevant *participating jurisdiction*.

(f) Where as a result of a review under the legislation (if any) referred to in clause 6.10.7(e)(3) of its decision to publicly release information or documents the *Jurisdictional Regulator* is not allowed to disclose particular information or documents provided to it for the purpose of performing its functions under the *Code*, the *Jurisdictional Regulator* may nonetheless use the information or document for the purposes of performing its functions under the *Code*.

(g) Nothing in clauses 6.10.7(d) and (e) is intended to affect a *Code Participant's* rights to seek a review under general principles of administrative law of the *Jurisdictional Regulator*'s decision to publicly release any information or the contents of any documents under clause 6.10.7(c).

3.4.5 The Commission's findings

The Commission believes that in general, the access code's proposed regulatory regime for distribution pricing acts in the interests of NSP's, network users and the general public. While outcomes from the process cannot be guaranteed, this flexibility is necessary to ensure that distribution network prices periodically respond to changing circumstances. In coming to this conclusion, the Commission has placed significant reliance on the jurisdictional regulator's independence as well as the sanctions for non-compliance with the code and undertaking.

Already the majority of the participating jurisdictions have established, or have indicated that they will establish, independent regulators for electricity network pricing. These decisions will increase the likelihood that electricity distribution prices will equitably balance of the interests of NSPs, network users and the general public. However, these decisions have not be fully implemented in all of the participating jurisdictions.

Moreover, the Commission's draft decision on the NEM access code questioned the likely effectiveness of the distribution pricing regime. In particular, the Commission noted that the jurisdictional regulator's access to relevant information in the required format is central to ensuring appropriately balanced pricing outcomes but that the code appeared to unnecessarily restrict the powers of the distribution pricing regulator. The Commission believes that the applicant's code changes relating to the powers of the jurisdictional regulators, in particular to their ability to publicly release regulatory information, has met the Commission's concerns as outlined in the draft decision.

3.5 Distribution pricing methodology

The previous section (3.4) outlined the principles the jurisdictional regulator should apply when determining the overall revenue or price cap for a distribution network. In addition, the code proposes a procedure whereby the regulator's overall revenue or price cap is translated into distribution network prices. The pricing methodology is flexible as it also provides considerable scope for the parties to negotiate network access prices.

3.5.1 What the applicant says

While differences exist, the distribution pricing methodology is broadly consistent with the transmission pricing methodology outlined above (section 3.3). For example, distribution pricing also involves a three step procedure to identify and allocate costs in order to determine distribution prices, namely;

1. Obtain a determination on the overall revenue requirement from the jurisdictional regulator.
2. Allocate the distribution network revenue requirement between the various classes of network services and then to different cost pools.
3. Recover the costs of the various network services through a series of usage prices.

The applicant (sub. p. 61) reiterated its view that the distribution pricing regime allows NSPs to develop innovative pricing solutions within a light handed regulatory oversight of monopoly network activities. While prices for regulated distribution assets will be largely based on average distribution costs, prices for distribution customers may vary depending on location, voltage level and load characteristics.

This pricing methodology (for further details see Box 3.5) gives the NSP considerable flexibility to determine prices for individual services. Even more flexibility is introduced by allowing the NSP and the network users to negotiate price outcomes, for example:

- As the code's distribution pricing methodology establishes maximum prices for the prescribed distribution services, lower prices can be negotiated. Any such negotiated prices have to be agreed to by both parties.
- The code's pricing formulae relate to standardised services (as defined in the code). Consequently, if a network user requires a service of a higher standard than prescribed in the code the price for such a service has to be negotiated by the relevant parties.
- The distribution NSP may require a network user to negotiate the terms of a prudential requirements (eg financial and non-cash capital contributions; certain pre-payments; guaranteed minimum service charges and/or quantities; or financial guarantees).

Moreover, where a distribution NSP has to construct a new connection, modify an existing connection or augment the network, the user may be required to make a capital contribution, pre-payment or financial guarantee. The NSP is not permitted to 'double-up' and recover such contributions through its network prices.

Box 3.5: Distribution network access pricing methodology

The price determination methodologies for the five classes of distribution network services can be summarised as:

1. **Entry services** — provided to *embedded generators* at a connection point;
   a) the connection agreement may specify an embedded generator's connection service costs;
   b) if not, an embedded generator's entry service costs are recovered by:
      i) creating cost pools which may differ on the basis of voltage levels and, in turn, load classes. The NSP can also divide the region into geographical areas to establish locational prices. However, the basis of the cost pools, geographical boundaries, use of locational prices and allocation of assets can only be done with the agreement of the jurisdictional regulator;
      ii) allocating the cost pools to embedded generators at the network coupling point (plus an amount for assets which jointly provide entry and exit services);
      iii) a fixed annual charge;
2. **Exit services** — provided to distribution network *customers* at coupling and connection points;
   a) the connection agreement may specify a customer's exit service costs;
   b) if not, a customer's exit service costs are recovered by:
      i) creating cost pools which may differ on the basis of voltage levels and, in turn, load classes. The NSP can also divide the region into geographical areas to establish locational prices. However, the basis of the cost pools, geographical boundaries, use of locational prices and allocation of assets can only be done with the agreement of the jurisdictional regulator;
      ii) allocating cost pools to customers at the network coupling point (plus amounts for assets jointly providing exit and entry services);
      iii) a fixed annual charge;
3. **Distribution use of system services** — provided to either embedded generators or customers but exclude exit and common services;
   a) use of system service costs are determined by creating cost pools which may differ on the basis of voltage levels and, in turn, load classes. The NSP can also divide the region into geographical areas to establish locational prices. However, the basis of the cost pools, geographical boundaries, use of locational prices and allocation of assets can only be done with the agreement of the jurisdictional regulator;

b) the portion of the cost pools allocated to the embedded generators:

i) must not exceed the long run marginal cost of network augmentation;

ii) are recovered by using the negotiated prices in the connection agreement (the jurisdictional regulator is to resolve any disputes) where the quantity is the nominated capacity;

c) the portion of the cost pools allocated to the distribution customers:

i) must be done on a cost reflective or other basis agreed with the jurisdictional regulator;

ii) the prices used to recover the costs can include a combination of demand, energy and fixed charges where the quantities may be either minimum, actual or agreed quantities;

4. **Common Services** — provided to ensure the integrity of the network to benefit all *customers* but cannot be allocated on a voltage or location basis;

a) cost pools are allocated to customers on a cost reflective or other basis agreed with the jurisdictional regulator;

b) the prices used to recover the costs can include a combination of demand, energy and fixed charges where the quantities may be either minimum quantities, actual quantities or agreed quantities;

5. **Firm access services** — relates to the risk premium for generators with connection agreements that include firm access compensation arrangements. The agreement will specify the amount of revenue to be recovered.

Source: NGMC 1996, National Electricity Code.

However, the code does not provide distribution NSPs with unlimited discretion in setting network prices. For instance, the code requires NSPs to seek the prior approval of the jurisdictional regulator if they are to establish prices which differentiate between zones and voltages. Moreover, the jurisdictional regulator may place limits on annual variations in published distribution service prices provided such limits are not inconsistent with any jurisdictional requirements or price caps.

The applicant (sub. p. 255) argued that the principles underlining distribution pricing protect the interests of the distribution NSPs by requiring the jurisdictional regulator to provide for a normal rate of return. The applicant also argued that this was also in the public interest ‘as it provides a signal to capital markets that there is a reasonable prospect of earning appropriate returns on future investments in the network.’

In terms of the interests of network users, the applicant (sub. p. 256) argued that the national guidelines will ensure that distribution network prices are consistent and will be in an easily understood format. Consequently, network users ‘will have full, easily understandable and comparable information of the services provided and the costs of each service.’ In addition, the applicant claimed that the code also promotes user interests by:

- requiring distribution NSPs to produce tariffs and the associated conditions for access to, and use of, the network;
- including incentive mechanisms which mimic market based prices; and
- not allowing NSPs to ‘double charge’ for any capital contributions made by users.

The applicant (sub. p. 256) argued that the access code promotes the public interest by emphasising contestability and the multi-tiered approach to regulation. While contestability has been enhanced by structural reform, the code offers further encouragement by the jurisdictional regulator's approach to the type and form of the regulation applied (ie regulatory effort is concentrated on the monopoly services not subject to any competition). The applicant's (sub. p. 256) assessment was that:

> The effectiveness of this regime in fostering efficiency and promoting cost savings will depend largely on the cost pressures applied by the regulators. It is contingent on access to reliable and detailed cost and operational information from the regulated entities.

The applicant concluded that the code adequately provides for the necessary information disclosure.

3.5.2 What the participants say

While the Victorian Distributors supported the flexibility of the distribution pricing regulatory regime, they argued that this flexibility was not matched by the distribution cost allocation and pricing methodology. For instance, the Victorian Distributors (sub. p. 22) stated that the code:

> ... details only one specific cost allocation and pricing approach. This approach is not necessarily the preferred cost allocation method and the price structure which will evolve from this approach will not necessarily promote economic efficiency or provide effective pricing signals to customers.

Consistent with their concerns relating to transmission pricing, a large number of participants argued that the distribution network pricing arrangements could also inhibit competition between existing and new generators. For example, Boral argued that the distribution pricing regulatory regime will not fully reflect locational benefits attributed to cogeneration.

While a number of participants commented on the level of averaging of distribution charges, there was no clear consensus view. On the one hand participants such as Boral were concerned about the level of averaging of distribution charges because of its likely impact on efficiency. Conversely, other participants, such as Integral Energy, supported averaging of network prices for reasons of equity and fairness.

Boral also raised concerns relating to the relative negotiating position of generators and distributors and the potential to abuse monopoly power; transparency of network charges when assessing locational choices for generation; and rights to bypass.

3.5.3 The Commission's considerations

In some respects, the diversity in the demand for electricity at the retail level provides greater opportunities to vary prices on the basis of the cost of delivering electricity at different voltage levels or different load classes in different parts of the distribution network. However, in other respects the nature of distribution networks point to a greater degree of averaging. For instance, distribution networks are highly integrated so a large proportion of assets and costs will be common to a large group of customers. Attempting to allocate such costs to individual customers on a cost reflective basis may often be arbitrary with little to be gained in terms of efficiency benefits. In addition, given past policies to cross-subsidise to provide uniform electricity tariffs, averaging network costs may be a necessary part of a transitional arrangement to avoid the possibility of price shocks for certain customer classes.

In order to balance these sometimes competing objectives, the code proposes a very flexible cost allocation and pricing structure which will be oversighted by the jurisdictional regulators. The proposed arrangements allows distribution network prices to vary on the basis of voltage levels, load classes and between geographical regions within a network. Network prices will also differ between the various network services.

Distribution network entry and exit services costs are determined either through a negotiated connection agreement or on the basis of cost pools which can differentiate between voltage levels, load classes and geographical boundaries. If the latter approach is adopted, the distribution NSP has to obtain the jurisdictional regulator's agreement on the nature of the cost pools including any differentiation of the basis of voltage levels, load classes and geographical boundaries. Entry and exit services costs are recovered through a fixed annual charge.

Distribution use of system service costs are determined on the basis of cost pools which have been approved by the jurisdictional regulator. The cost pools can differentiate between voltage levels, load classes and geographical boundaries. The cost pools allocated to embedded generators must not exceed the long run marginal cost of network augmentation and are recovered through negotiated prices. The cost pools allocated to distribution customers can be done on either a cost reflective or some other basis. The cost pools can be recovered through a combination of demand, energy or fixed prices and on the basis of either minimum, actual or agreed quantities.

Common services are also allocated to customers through cost pools which have been approved by the jurisdictional regulator. The cost pools can be recovered through a combination of demand, energy or fixed prices and on the basis of either minimum, actual or agreed quantities.

Given the flexibility of the proposed arrangements, the Commission believes that the distribution pricing methodology has the capacity to act in the interests of facility owners, network users and the wider Australian community. The Commission has reached this conclusion on the basis that the code allows the network service provider to develop, in conjunction with the jurisdictional regulator, distribution network prices which are tailored to meet the individual circumstances which exist in their networks. In addition, the jurisdictional regulators are responsible for ensuring that the distribution prices reflect an appropriate balance between efficiency and equity considerations.

However, this flexibility comes at the cost of the certainty of the distribution price outcomes. Consequently, the Commission is not in a position to categorically state what the likely impact distribution pricing will have for the interests of facility owners, network users and the wider Australian community. While greater certainty in the price outcomes may be desirable, including additional guidelines into the access code would be counter productive if it limited the NSPs' and jurisdictional regulators' ability to develop efficient and equitable pricing solutions designed to suit individual circumstances. Clearly, and as the applicant stated, the effectiveness of the distribution pricing regime depends on the jurisdictional regulators.

Part C General access pricing issues

3.6 Asset valuation

3.6.1 What the applicant says

Broadly consistent principles govern the valuation of transmission and distribution network assets. In general, the code proposes that, where applicable, network assets will be valued in a manner consistent with either a take or pay contract or a NEMMCO augmentation determination. After 1 July 1999, existing assets can be revalued, and new assets valued, on a basis determined by the regulator (ie the ACCC for transmission and jurisdictional regulators for distribution networks). In determining the basis on which assets will be valued, the regulator must have regard to:

- the COAG agreement that deprival value is the preferred approach for network assets;
- any subsequent COAG decisions; and
- any other matters to achieve consistency with code objectives — eg NSPs can earn a reasonable rate of return but not extract monopoly rents and there must be reasonable recognition of pre-existing government policies regarding asset values, revenue paths and prices.

In the interim period up to 1 July 1999, asset values will be determined either by the jurisdictional regulator or in a manner consistent with the jurisdiction's regulatory asset base. For transmission networks, any such asset values must not exceed their deprival value and can be independently verified by the ACCC through a process agreed to by the NCC.

While the code does not define the deprival valuation methodology, the definition used by the applicant is more consistent with an optimised deprival value definition rather than the deprival value definition used by the Steering Committee on National Performance Monitoring of GTEs (1994 p. 73). For instance the applicant (sub. schedule 18 p. 3) states that the:

> ... Deprival Value is the lower of the optimised replacement cost of an asset and its economic value to the business. Under the Deprival Value method, assets are valued at replacement cost and then adjusted for any over-capacity and lower consumer value.

The applicant (sub. pp. 242–3, 247) defended their choice of the deprival approach to asset values on the basis that:

- empirical studies in Victoria indicate that current cost asset values would not lead to inflated asset values;
- COAG supported its adoption because of its desirable equity and efficiency characteristics;
- it is to be used as a ceiling and owner governments may elect to adopt lower asset values to avoid any price shocks; and
- it is neutral between existing and new assets.

The applicant indicated that this approach to asset revaluation protects the public interest because it encourages prices to reflect efficient costs and NSPs to make efficient investment decisions. For instance, the applicant (sub. p. 234) stated that:

> ... the basic purpose of undertaking periodic deprival value revaluation is:
>
> - to ensure that prices for monopoly services reflect the cost of efficient new entrants to the market (thus ensuring efficient and equitable prices); and
> - to provide incentives to monopolists to undertake adequate analysis of the uncertainty associated with future changes in technology, and electricity supply and demand before making an investment decision (thus ensuring that the grid company faces incentives to invest in an optimum manner).

For similar reasons, the applicant (sub. p. 242) argued that deprival valuation would also protect users from monopoly profits by 'gold plating' capacity; an outcome which is possible through historic cost valuation. Moreover, past monopoly profits could not be capitalised as the ACCC has the right to verify the opening values of transmission network assets.

The applicant (sub. pp. 239–40) also argued that deprival valuation will ensure the efficient utilisation of existing network resources as:

> A key objective of the deprival value methodology is to ensure that the impacts of new technologies (in the network sector and in substitute sectors such as distributed generation) are taken into account in the valuation of assets for revenue purposes. The 'economic value test' provides a cross-check of network asset values against the cost of bypass options. Where the cost of the bypass option is cheaper, the existing network asset value and its associated revenue requirement are reduced accordingly.

While the applicant (sub. p. 234) recognised that asset revaluations can increase the uncertainty of investment returns to service providers, they argued that:

> ... provided the estimated cost of capital reflects the risks inherent in such arrangements, the arrangements should not pose an undue threat to the legitimate business interests or investments of the service provider.

The applicant argued that the NSPs are so protected as the code:

- requires the regulator to have regard to pre-existing government policies with respect to asset values, revenue paths and prices as well as for the need to provide a fair and reasonable risk adjusted cash flow rate of return to the transmission NSP; and
- quarantines the NSP from stranded asset risk where other parties were involved in the investment decision (eg existing take-or-pay contracts or network augmentation resulting from a NEMMCO determination).

Moreover, in those circumstances where assets values have some protection from revaluation (eg when NEMMCO requires the augmentation of a network), the applicant (sub. p. 240) argued that network users are protected from stranded asset risk as NEMMCO is required to make any such determinations in a transparent and publicly accountable manner based on a 'net benefits to customers' criteria.

3.6.2 What the participants say

A number of participants were highly critical of the code's reference to the deprival methodology for asset valuation. For example, Australian Paper (sub. p. 2) strongly disagreed with the deprival system of asset valuation:

> ... as it effectively writes off all depreciation contributed over the years and even allows the asset owner to increase the notional value above its actual cost. Further it permits any contribution to future depreciation also to be written off, to the benefit of the owner. Perhaps as an alternative the regulator should either use the deprival system but eliminating depreciation as a cost, or use the actual cost but allowing depreciation as an operating cost. We have already seen governments use the deprival system to maximise assets for subsequent sale.

The EUG and the BCA were also both highly critical of the deprival asset valuation methodology. For example, the EUG (sub. p. 65) stated that deprival valuation 'will inevitably lead to inflated asset valuations which will find their way into transmission charges.'

This view was also reflected in the concerns (BCA sub. p. 19) of 'Business Council companies that government owned networks are seeking to capture the benefits of competition through network pricing.' For example, the BCA (sub. pp. 19 & 21) argued that this is reflected in excessive profit levels and that:

> ... under the new regime, network prices being quoted or applied are much higher than experienced previously in contracts and tariffs — sometimes by a factor of between two and three;

In addition, the BCA (sub. p. 24) indicated its objections to the code's particular application of the weighted average cost of capital and depreciation provisions. BHP argued that a consistent approach has to be adopted in determining the relationship between benchmark returns and asset valuation methodologies. For instance, BHP (sub. p. 3) observed that:

> The appropriate WACC depends on many factors including whether the capital base on which the rate of return is to be applied is or has been valued with inflation included. Typically a nominal rate of return is used against a non-inflating capital base. If the asset is to be inflated year by year, a real rate of return should be applied. Similarly, if the capital base is to be inflated on an interim basis, a real rate of return should also apply.

Australian Paper's concerns about the deprival system of asset valuation were closely linked to their call for the transmission and distribution regulator to be fully independent of executive government. In a similar vein, the remedy proposed by the EUG involved adopting, at least initially, IPART's approach which builds in reductions in asset values ranging from over 40 per cent for the rural distributors, 17 per cent for EnergyAustralia and around 35 per cent for TransGrid.

3.6.3 The Commission's considerations

The code adopts a flexible approach to asset valuation and allows regulators to use any methodology to value assets (see Box 3.6 for a discussion of a number alternative asset valuation methodologies). However, the code does not provide regulators with unlimited discretion in this matter and stipulates that the regulators have regard to the COAG decision that the deprival methodology is the preferred approach to valuing network assets.

The applicant argued that the deprival methodology possesses a number of advantages in that existing network assets could be made equivalent to the costs of new entrants and new technologies. The deprival methodology also allows the regulator to write down gold plated investments thereby providing an incentive for network operators to invest efficiently.

In order to achieve these advantages, the asset valuation methodology has to incorporate an optimisation process. While the application and the NGMC's earlier documents makes it clear that an optimisation process is intended, the code refers to deprival valuation which usually incorporates replacement costs without an optimisation process. Consequently, in its draft decision the Commission stated that:

> **In order to avoid any unnecessary confusion, the Commission believes the code should incorporate a definition of the deprival valuation methodology which includes a reference to optimised replacement costs.**

However, despite its theoretical attractions, a number of business users were highly critical of the deprival methodology as it can be used to inflate asset values over historical cost. Participants argued that this has already resulted in a two- or threefold increase in network prices. This view tends to be supported by simulations conducted by IPART in New South Wales which found that using the deprival value approach, without regard to other market and financial indicators of asset values, may overvalue existing assets considerably, resulting in excessive rates of return and an initial rate shock for users.

In addition to participants' concerns, from a regulator's perspective assessing asset values using a deprival approach is likely to be information intensive. It may also involve seemingly arbitrary decisions on the part of the regulator. For instance, in practice, it may be difficult to distinguish between:

- a stranded asset and an asset with a reduced economic life; and
- network augmentations which reflect 'gold plating' and augmentations which reflect the lumpy nature of network investments or a network operator's commitment to providing a reliable and safe network.

Given these practical considerations, it could be expected that the pricing regulatory reviews will be hotly contested by both the network service providers and by network users. Consequently, the Commission believes that, in contrast to the applicant's view, it will be difficult to characterise the access code's pricing regime as 'light handed' if asset values are determined by the deprival approach.

Nevertheless, the Commission accepts the applicant's arguments that the deprival methodology possesses a number of attractive features. The Commission also recognises that the strict adherence to the deprival asset valuation approach may tend to over value network assets, and so result in excessive prices and rates of return. However, there is no guarantee that one or the other of these outcomes will occur.

The flexibility of the code's pricing regime means that outcomes can be achieved which are superior to those based on other asset valuation methodologies. The Commission does not want changes in the code which would preclude this possibility. However, it is equally important that network users are not exposed to prices whereby monopoly rents are capitalised into assets values.

These issues of balancing regulatory flexibility with certainty of outcomes was addressed earlier in this chapter (section 3.4.3) when the Commission commented on the proposed regulatory regime for distribution pricing. The Commission believes that these comments are particularly pertinent to addressing participants' concerns over asset valuation methodologies and outcomes. In particular, the Commission believes that it is important for the regulators to be independent from the other policy development processes of government. Moreover, the asset valuation processes should be transparent to ensure the regulator and its decisions are accountable to all parties. By doing so, the regulator will be seen to be an independent umpire capable of making decisions in the public interest and without a vested interest in the outcome.

For its part, the Commission's over-riding objective as the regulator of transmission pricing will be to ensure that transmission prices do not reflect monopoly pricing practices. In this context, asset values will have a significant bearing on the nature of the pricing outcomes. Accordingly, the Commission emphasises that the code provides the transmission pricing regulator with the right to independently verify the opening asset values.

Similarly, given the concerns expressed by participants about the deprival methodology, the Commission intends to exercise its code power to determine the basis on which transmission assets will be valued. Consequently, the Commission's acceptance of the access code is on the basis of the flexibility in the choice of asset valuation approaches and should not be seen as an endorsement of a particular valuation methodology. The Commission's choice of asset valuation methodology will be made at the time it performs its role as the regulator of transmission network prices. Moreover, any future decision by the Commission to move away from the deprival approach will be consistent with the code's other guidelines; in particular that any such determination by the Commission will give transmission NSPs a fair and reasonable rate of return, will have regard to COAG's preference for the deprival approach and will give reasonable recognition to pre-existing government policies regarding asset values, revenue paths and prices.

The code provides guidance concerning the preferred asset valuation methodology and discusses at some length the determination of the weighted average cost of capital. However, in practice, the determination of asset values and rate of return are related matters (eg the approach the regulator takes to optimising network assets will impact on the risk of the NSP's business). In this context it is significant that the code does not fully specify the approach the regulator should adopt. As a result a number of participants expressed concerns about inflated asset values and the potential for double counting. In order to address this concern, the Commission intends to use the flexibility provided for in the code to avoid any double counting by ensuring that the asset valuation methodology is fully consistent with the rate of return. For example, where the asset values reflect current costs (eg the deprival approach) the effect of inflation has already been taken into account so the appropriate rate of

Box 3.6: Overview of alternative asset valuation methodologies

There is no single approach to asset valuation that is appropriate in all circumstances. Consideration needs to be given to the purpose of the valuation and the availability of data. While the Steering Committee on National Performance Monitoring of GTEs recommended using deprival value as the best asset valuation methodology for performance monitoring purposes, it does not follow that it is necessarily the best method for the purpose of price regulation. In this case, consideration should also be given to the rate of return and the pricing objectives.

The **historical cost** method values assets at their original purchase price. It has the advantages that it is administratively efficient and can be easily audited because the data should be available from financial statements; it is relatively inexpensive since it does not require experts to determine costs; and it is objective because it relies on actual data rather than judgement.

The disadvantages of this valuation method are that it may understate asset prices in times of inflation and overstate asset prices in times of technological change; it may lead to unstable prices (eg prices may rise when new more expensive assets replace existing assets); and data may not be available or may be inadequate (eg if the asset was purchased several periods prior to the valuation). However, some of these deficiencies can be overcome through adjustments to asset lives, depreciation schedules and rates of return.

Reproduction cost method values assets at the current cost of reproducing the existing assets. A disadvantage with this approach is that does not give consideration to whether the current asset is the most efficient means of meeting current requirements.

The **replacement cost** methodology calculates the cost of replacing an asset with another asset (not necessarily the same) that will provide the same services and capacity as the existing asset. Advantages of this method are that: assets are valued in current prices; and it may provide an incentive for efficient investment decisions as it allows the regulator to reduce the value of the asset once it becomes aware that a more efficient low cost alternative asset was available.

The disadvantages of replacement cost valuation are that it involves estimation and judgement, which is open to legal challenge; the information is more expensive to collect than historical cost data because it requires expert advice (eg from engineers); assets may be overvalued; and it may lead to price instability if the technology and input prices are unpredictable.

Optimised replacement cost is a variant of the replacement cost valuation methodology which measures the cost of the most efficient method of providing the services of the current asset.

Optimised replacement cost has the advantage that asset values can be adjusted where, for example, the service capacity of current assets is excess to requirements as a result of changes in demand or over investment in the past (eg from gold plating or inefficient decisions). A disadvantage of this method is that it involves a greater degree of judgement and expert advice than replacement cost approach.

Deprival value approach is the minimum loss that would result if the business were deprived of the asset. For example, where the asset can and should be replaced, the deprival value is the replacement cost. If the asset would not be replaced, then the deprival value is the greater of the net present value of expected cash flows from continued use of the asset or the net realisable value of disposing the asset. In other words, it is the minimum of an asset's replacement cost or its economic value.

Optimised deprival value is a variant of the deprival value approach by taking into account the most efficient method of providing the asset's services if the asset is to be replaced. An advantage of this approach is that it discourages inefficient investment because regulators will revalue inefficient assets down to their optimised replacement cost.

A disadvantage of any valuation method that involves optimisation is that it requires expert engineering opinion, which increases the complexity and cost of the valuation. It is also likely that the valuations would be subject to legal challenge.

Both deprival value and optimised deprival value are criticised as introducing a circularity problem. That is, these techniques require an estimation of the future returns on the asset, which is what the access prices set by the regulator are suppose to determine.

The **scrap value** approach attaches to an asset the value of the asset in its next best alternative use. The scrap value of sunk assets, which have no alternative use, will be close to zero. If an asset is valued below scrap value, it will be economic to transfer the asset to this alternative use.

Scrap value provides a useful lower limit to asset valuation. However, it may be considered unfair as the return on the investment may be below the opportunity cost of capital. Another disadvantage of this approach is that it may not provide incentives for future investment.

Source: Bonbright, J. et al 1988, *Principles of Public Utility Rates*, Public utilities reports Inc, Virginia.

Choy, E. 1996, *Asset Valuation by GTEs: an Evaluation of Pricing Issues*, Australian Society of CPAs' Public Sector Accounting Centre of Excellence, Melbourne.

Steering Committee on National Performance Monitoring of GTEs, 1994, *Overview: Guidelines on Accounting Policy for Valuation Assets of GTEs*, Industry Commission, Melbourne.

return is the real rate and not the nominal rate. Similarly, where a regulator adopts a vigorous application of the deprival methodology to strand assets, the additional risk should be reflected in the rate of return.

3.6.4 Applicant's response

Chapter 10 of the Code includes a definition which states that deprival value is:

> A value ascribed to assets which is the lower of economic value or optimised depreciated replacement costs.

3.6.5 The Commission's findings

The Commission believes that the code acts to promote the interests of:

- network users and the wider community by allowing the regulators flexibility in assessing asset values in order to limit the ability of network service providers from exploiting their monopoly powers; and
- facility owners by providing guidelines which constrain regulators from arbitrarily determining asset values.

However, these attributes of the code are insufficient to guarantee that regulators will not determine asset values which are incompatible with efficient pricing and therefore are contrary to the interests of network users. Therefore, to reduce the likelihood, and perception, that the electricity pricing regime will be used to inflate access prices, the Commission believes that the jurisdictional regulators should be statutorily independent of government. Already the majority of the participating jurisdictions have established, or have indicated that they will establish, independent regulators for electricity network pricing. The Commission has also received assurances from the South Australian government that this issue will be addressed within the next twelve months and noted that South Australia is already committed to an independent regulator for gas distribution pipelines.

3.7 Cogeneration and embedded generators

3.7.1 What the applicant says

Cogeneration and embedded generation more generally provides a number of benefits to electricity networks in terms of network support and, as they are usually located close to load, they can reduce the demand for network augmentation. Embedded generation also provides a number of benefits to the broader electricity market. This was recognised by the applicant (sub. p. 92) when, addressing the benefits of the market arrangements, it argued that in:

> ... the longer term, competitive sourcing of generation and third party network access enables new entrants to build more efficient (less expensive) generation plant ...[which is] more and more likely to be high efficiency gas fired, with an increasing emphasis on cogeneration.

The applicant (sub. p. 248) stressed the importance of the pricing arrangements for the NEM as they provide the commercial basis for open access to transmission networks and they allow participants to trade freely in the energy sub-market. In particular, the applicant argued that:

- network pricing that improperly allocates costs could lead to significant distortions as power stations and major load could be encouraged to locate without regards to costs on existing users and the availability of spare capacity elsewhere on the network; and
- while no pricing methodology can exactly reflect costs to individual participants, greater cost reflectivity can reduce the level of cross-subsidy — eg uniform pricing has tended to encourage the development of central power generation facilities to supply remote areas when local generation may well have provided a more efficient lower cost solution.

As outlined in the previous sections of this chapter, the transmission and distribution use of system and common service charges largely fall on electricity users. Generators pay network charges for connection assets they use, for the use of system assets they agree to and for the firm access arrangements they can negotiate. On the basis of this network pricing structure, the applicant argued (sub. p. 251) that the price for each participant is:

> ... influenced by the location of that participant in the network relative to generation injection points, and the assets employed in providing network service.

However, the code also incudes specific provisions to take account of the network benefits that generators can provide. First, when considering network augmentation, the code allows NSPs to implement a generation option as an alternative. To the extent that such a generator provides a network support function, the costs of that service can be included into the transmission or distribution NSP's asset base for price determination purposes.

Second, the code allows a distributor to make payments to an embedded generator. Any such payments are to be capped at the long run marginal cost of augmenting the distribution network and will be added to the distributor's annual revenue requirement. The code (section 4.5 of schedule 6.6) adds that as a general principle any such arrangements between an NSP and a generator should be commercial and may include a competitive tendering process to 'ensure equal opportunity' for all generators.

3.7.2 What the participants say

A significant number of participants expressed concerns that the pricing arrangements did not provide adequate locational signals to generators, in particular to co-generation vis a vis traditional coal fired technologies.

VPX (sub. p. 10) stated that the 'provision of locational signals for new generators is the most important objective of the transmission pricing arrangements.' However, VPX argued that the absence of detailed pricing arrangements for generators, with transmission prices allocated to customers, would result in

> ... distortions in the provision of new generation since it would not allow the transmission costs of new generators to be considered in the generators investment decision.

Boral Energy (sub. p. 6) stated that:

> ... locational benefits (eg for cogenerators) must be fully reflected in network charges as it is these which, for the short term at least, will be the main competitive threat to incumbent generators. Cogeneration also provides a key competitive pressure on Network Service Providers (NSPs) by effectively enabling bypass of certain assets.

Similarly, the Australian Cogeneration Association (sub. p. 6) argued that the NEM arrangements encourages competition between generators on the basis of a wholesale price:

> ... with no allowance for the cost of transmitting the power to consumers. Cogeneration competes on a delivered cost basis and thus is disadvantaged. ... The signals that the current market structure sends industry participants encourages large scale power plants, located close to the lowest cost fuel source with negligible recognition of locational benefits or environmental costs (eg greenhouse gas emissions).

The ACA (sub. p. 7) stated that its biggest concern is that the 'historical bias against cogeneration is not institutionalised or legitimised by way of the NEM'. The ACA (sub.

pp. 11–2) complained that the absence of efficient locational incentives for generation reflected that, during the code's development, 'very little if any consultation was undertaken with cogenerators as the potential new entrants'. However, the ACA stated that this was not surprising as the NGMC drew heavily on the resources from the existing electricity authorities, whether it be as members or in an advisory capacity.

The ACA's concern that the code's pricing arrangements would have a detrimental impact on the environment was echoed by both Environment Australia and Greenpeace. However, these two bodies argued that the absence of efficient locational incentives would not only impact on the cogeneration but on demand side management (ie energy efficiency services and load management) as well.

To rectify this situation a number of participant suggested alternative strategies. For instance, Sithe Energies and the ACA suggested two alternative strategies. Sithe Energies' (sub. p. 2) preferred approach was to levy TUOS charges on generators using a load flow methodology analogous to the current approach whereby TUOS costs are allocated to distributors. Alternatively, Sithe Energies (sub. p. 3) argued that in the absence of any changes to the incidence of TUOS charges, then the presence of an embedded generator in a distribution network should reduce the allocated TUOS costs in line with the distributors' lower peak demand and energy consumption. Sithe Energies argued that the distributor should then pass on to the embedded generator the resultant lower transmission charges.

These views were echoed by the ACA which argued that TUOS charges should be borne by generators but added (sub. pp. 18–9) that the avoided transmission use of system charges should be passed on to the cogenerator which would, in turn, be passed onto the cogenerator's customers. In addition, the ACA argued that in order to have transparent pricing which retains incentives for efficient behaviour, the TUOS charges should be unbundled from the DUOS charges (ie the code currently levies TUOS charges on distributors which are then passed on to the distributors' customers on the basis of their DUOS charges). In a supplementary submission the ACA (sub. p. 4) argued that:

> Access cannot be obtained to the distribution and transmission networks separately. The prices for these services are bundled and in Victoria and New South Wales applied to 'end use' customers on a highly averaged basis that does not reflect the cost of supplying or using the network.

The ACA argued (sub. p. 6) that as all contestable sites are required to install the appropriate metering, then it would be easy to levy the TUOS charges at each connection point based on that customer's demand and energy requirements. The ACA argued that this approach would encourage electricity retailers to assist their customers to undertake demand side responses.

Rather than having embedded generators capture the benefits of avoided transmission charges, Integral Energy (sub. p. 6) argued that 'the correct price signals should flow from an appropriate transmission use of system charge, ie that generators should pay an appropriate component of transmission.'

In a similar vein, Australian Paper (sub. p. 2) argued that:

> ... currently TUOS is levied on DB's, but it should be levied on generators remote from their load centres as TUOS is a cost to deliver electricity from the fuel source to the user. Embedded generators should have the recognition that they have paid for the transport of fuel to the user rather than the transport of electricity.

Alternatively, VPX (sub. p. 10) supported:

> ... the concept of firm access for generators as one way of providing the necessary signals. This approach, which is basically a limited application of a nodal spot pricing methodology overlaid with transmission hedging contracts provides appropriate long term investment signals while allowing utilisation of any short term capacity at a lower price.

Despite these concerns, other participants warned against providing embedded generation with preferential treatment, in particular in relation to stand-by charges. For instance, Delta Electricity (sub. p. 2) argued that the owners of embedded generation:

> ... are typically consumers of electricity from the network during periods when the embedded generator is out of service for routine maintenance or forced outages. Accordingly, they require the capacity (and therefore the capital investment in the infrastructure) to exist for such periods. If an embedded generator was not to pay the same network charges as other generators then they should be required to pay an additional levy for availability ie. a fee to cover the use of network assets when the embedded generation is not available.

Issues arising from the draft decision

In the draft decision, the Commission sought to have the issues of the incidence of TUOS charges addressed by the NECA review of transmission charges. As an interim step, the Commission also sought to have inserted into the code an IPART style 'with and without' test which would provide embedded generators some recognition of avoided network costs and a reduction in network charges. The Commission also sought the applicant to unbundle TUOS and DUOS charges and to insert into the code powers for the regulator to impose accounting and functional separation of a network's contestable activities from its non-contestable activities.

Rather than imposing an IPART style 'with and without' test, a number of participants (eg Ampol, the ACA, Australian Paper and the EUG) argued that the Commission's interim position should be to levy TUOS charges on generators. For example, the EUG argued that, notwithstanding the NECA review, the Commission should provide a more concrete direction on network pricing. The EUG and Cadia Mines sought the unbundling of transmission (TUOS) and distribution (DUOS) use of system charges, and the EUG added that at least 50 per cent of TUOS charges should be levied on generators.

To the extent that generators commented on network pricing issues, their concerns were focussed on firm access issues which are discussed elsewhere in this decision on the NEM Access Code.

The BCA supports the Commission's condition for the interim application of an IPART type test, but does not support the proposed prices methodology and allocation of costs to customers.

Networks' response

The incumbent New South Wales distribution NSPs argue that the regulatory arrangements for network pricing for generators should provide efficient locational signals across transmission and distribution networks. The New South Wales distribution NSPs, United Energy and TransGrid agree that this is an issue for the NECA review.

The distribution NSPs question whether the IPART guidelines are workable, adding that they have never been tested or used on any embedded generation scheme in New South Wales. Similarly, Powercor supports the general thrust of the Commission's recommendation but argues that the IPART guidelines do not provide sufficient detail for specific projects and may lead to sub-optimal outcomes if the regulatory environment is not fully considered. SEQEB argues that the IPART guidelines were just one approach and it proposed a number of code consistent alternatives.

CitiPower and Powercor indicate that they see merit in having ring fencing guidelines relating to the accounting separation for regulated and non-regulated activities. Beyond this, Powercor does not support full functional separation arguing that it would increase costs to end customers by requiring the businesses to duplicate corporate overhead, billing and settlement functions. Solaris and United Energy support the Victorian approach where functional separation involves accounting separation and information control rather than corporate disaggregation.

3.7.3 The Commission's considerations

The code's treatment, and the participants' discussion, of embedded generation raises two separate but related concerns. The first relates to the efficiency incentives from levying the majority of network use of system and common service charges onto network customers. The second concern relates to the code's mechanisms to introduce locational incentives for embedded generation and the implications they may have for the relationship between NSPs and generators.

The code provides some scope for generators to contribute to TUOS charges. However, any such contribution is by the mutual agreement of the generator and the NSP and, as a result, this arrangement is not well defined. Conversely, the code documents, in much greater detail, the arrangements by which network use of system and common service charges will be levied on network customers. While the exact impact of this arrangement is unclear, it is likely that the majority of network charges will be paid by network customers. Consequently, network charges are unlikely to systematically influence generators' location decisions. Moreover, as generators will be dispatched into the wholesale market largely on the basis of generation and connection asset costs, the incidence of network charges appears to disadvantage embedded generation which competes on a delivered cost basis.

Conversely, the beneficiaries of this arrangement are likely to be those generators which are located at quite some distance from the load. As a result, this arrangement will encourage the transport of electricity across state boundaries and will thereby promote the development of a more integrated national electricity market with the potential for consequential benefits for electricity users.

On the balance of the arguments presented, the Commission recognises the strengths of the criticisms which have been directed towards the proposed incidence of network use of system charges. However, determining the appropriate division of network charges between the various network users is a complex task of identifying the directly attributable costs of each user as well as finding efficient and equitable mechanisms for allocating any common costs or cross-subsidies. For this reason, the Commission is not in a position to reject the code's proposed incidence of TUOS charges. Rather, the Commission maintains the view that the incidence of TUOS charges should be re-examined as part of NECA's review of transmission pricing.

As the Commission does not want to pre-judge the outcome of the NECA review, in its draft decision the Commission argued that the code should, in the interim, encompass some remedy to introduce additional locational signals. As advocated by participants, mechanisms similar to those adopted by IPART in New South Wales appear to provide some relief for embedded generators while maintaining the proposed incidence of network use of system charges. For instance, IPART's approach allows distributors to negotiate the pass through to embedded generators the benefits of reductions in the variable components of the transmission charge. In this context, the Commission acknowledges the merits of the participants' arguments for unbundling TUOS and DUOS charges. Consequently, in its draft decision the Commission stated that:

> **The Commission is seeking a commitment from NECA that their forthcoming review of transmission pricing includes an assessment of the desirability of allowing transmission NSPs to financially compensate generators for the avoided costs of augmenting their network. The Commission will also encourage NECA to reassess the desirability of shifting some of the incidence of network use of system charges from consumers and on to generators.**

In the interim, the Commission believes that mechanisms, similar to those adopted by IPART in New South Wales, should be included into the code to allows distributors to negotiate the pass through to embedded generators the benefits of reductions in the components of the transmission charges. In this context, the Commission encourages NECA to alter the code so that customers are separately levied the TUOS and DUOS charges.

In terms of the savings to a distribution network, the code goes somewhat further and allows a distributor to make payments to an embedded generator for amounts up to the long run marginal cost of augmenting the distribution network. All such payments will be added to the distributor's annual revenue requirement. Consequently, this approach allows embedded generators to be rewarded not only for savings in the variable components of distribution charges but also allows them to be compensated for the capital costs avoided by having to augment a distribution network. This approach goes some way to addressing the participants' concerns that embedded generation will not be appropriately rewarded for avoided network costs.

In addition, this approach addresses another potential deficiency with the current network pricing regime. As the code has not fully adopted a nodal pricing regime, differences in the wholesale price of electricity will only occur between transmission regions. Therefore, the wholesale electricity price will not signal the need for additional network augmentation, embedded generation or demand side options within a transmission or distribution region. The payment arrangement between distribution NSPs and embedded generation goes some way to resolving this deficiency.

Despite the attractiveness of this approach, the incentives it provides are limited in scope and are not entirely consistent with a number of other parts of the code. First, large generators have a similar relationship with intra-regional connections. While the code's augmentation procedures require that the viability of all such options be assessed prior to a new investment occurring, there is no specific provision for payments to base load generation to be added to a transmitters regulated revenue base. Although the code does allow those generator assets which provide network support functions to be included in an NSP's regulated asset base. Second, and as was discussed above, embedded generators can also lead to avoiding augmentations to a transmission network. Yet despite this similarity, there is no provision in the code to allow, or even require, transmitters to make payments to embedded generators. Consequently, it is evident that the code only provides very limited incentives for the efficient location of generators and, therefore, can distort generators' demand for network facilities.

Arising from the code's attempts to introduce appropriate financial incentives for investments in generators and network facilities, in its draft decision the Commission identified a supplementary concern that there are no detailed guidelines governing the relationship between the NSP and the generator. This applies whether the arrangement is to include some generation assets into an NSP's regulatory asset base or whether a distributor's payments to an embedded generator are included in its regulated revenue requirement.

Without detailed guidelines, the Commission argued that it might be possible that, in either set of circumstances, an NSP could use the arrangements to discriminate in favour of a generator in which it has an equity involvement and to penalise a wholly independent generator. If such an outcome were to arise it would reverse the policy decisions of the participating jurisdictions to structurally separate network activities from generation. These decisions were implemented to avoid the circumstances whereby the operators of networks could use their market power to influence outcomes in contestable markets such as generation.

While issues of structural reform and the separation of network and contestable activities (eg generation and retail) may be beyond the scope of an access code, administrative arrangements to deal with residual concerns relating to cross-ownership linkages are clearly within the bounds of an access code as evidenced by the proposed gas code. Consequently, in its draft decision the Commission argued that it is important that the access code provides clear scope for regulators or jurisdictional governments to develop ring fencing guidelines for the accounting and functional separation of the contestable and non-contestable activities of the network service providers. Specifically, the Commission stated that:

> **The Commission is seeking NECA to include clauses into the access code which provides clear scope for regulators or jurisdictional governments to develop ring fencing guidelines for the accounting and functional separation of the contestable and non-contestable activities of network service providers. In order to achieve consistency in the arrangements, the code should also incorporate provisions which would allow the ACCC to coordinate the development of the ring fencing guidelines.**

The Commission added that the ring fencing guidelines would be in the public interest and in the interest of access seekers as they would serve to reinforce the effectiveness of the regulatory process and would help in avoiding discrimination between generators in the circumstances where cross-ownership may exist. This would be achieved both by ensuring that regulated activities do not cross subsidise contestable activities and by restricting information flows between regulated and contestable activities.

3.7.4 Applicant's response

The applicant has accepted the Commission's interim and longer term proposals to insert into the code an IPART style "with and without" test for avoided network costs as well as to reconsider the incidence of TUOS charges as part of its review of transmission network pricing. The IPART style "with and without" test has been inserted into clause 5.5 of the code which deals with access arrangements for generators and states:

> (f) The *Network Service Provider* and the *Generator* shall negotiate in good faith to reach agreement as appropriate on the:
>
> <u>(3) amount to be passed through to the *Generator* (where the *Generator* is an *Embedded Generator*) for avoided *transmission use of system charges* that would otherwise have been payable by the *Network Service Provider* as a result of the *Generator* not being connected to its *distribution network*;</u>
>
> <u>(h) Any payments to *Embedded Generators* under clause 5.5(f)(3) are to be included as part of the *aggregate annual revenue requirement* of the *Network Service Provider* and are to be recovered in the same manner as payments to *Embedded Generators* under clause 6.13.3(d).</u>

In addition, item 5 of the terms of reference state that NECA's review of transmission and distribution pricing should specifically consider, amongst other things:

- appropriate guidelines for negotiations between distribution network service providers and embedded generators on the pass-through of the effects of bringing those generators into the network on the components of transmission charges; and
- the appropriate incidence of TUOS charges, and the pros and cons of unbundling transmission and distribution use of system charges.

NECA has also accepted the Commission's recommendations giving the regulators the power to develop ring-fencing guidelines. The code changes require the ACCC, as the regulator of transmission networks, to develop ring fencing guidelines for the accounting and functional separation of regulated and non-regulated services of the transmission NSPs. These ring fencing guidelines are to be developed in consultation with the jurisdictional regulators and each participating jurisdiction. Similarly, the jurisdictional regulators are required to develop ring fencing guidelines for the distribution NSPs in their jurisdiction. To ensure consistency, the jurisdictional regulators are required to consult with the other regulators and to take into account the ring fencing requirements for other utility businesses.

Reflecting these objectives, NECA has inserted clause 6.20 into the code which states:

6.20 RING FENCING GUIDELINES

6.20.1 Compliance with Ring Fencing Guidelines

All *Transmission Network Service Providers* and *Distribution Network Service Providers* must comply with the *Transmission Ring-Fencing Guidelines* and the *Distribution Ring-Fencing Guidelines* prepared in accordance with clause 6.20.2 as from the time that any derogation from this clause 6.20 contained in Chapter 9 ceases to apply in respect of the *participating jurisdiction* in which the *Transmission Network Service Provider* or *Distribution Network Service Provider* is located.

6.20.2 Development of Ring Fencing Guidelines

(a) Ring-fencing guidelines must be developed by the *ACCC* in consultation with the *Jurisdictional Regulators* and each *participating jurisdiction* for the accounting and functional separation of the provision of *prescribed services* by *Transmission Network Service Providers* from the provision of other services by *Transmission Network Service Providers* (the "**Transmission Ring-Fencing Guidelines**").

(b) Ring-fencing guidelines must be developed by each *Jurisdictional Regulator* in consultation with the *ACCC* and each other *Jurisdictional Regulator* for the accounting and functional separation of the provision of *prescribed distribution services* by *Distribution Network Service Providers* located in that *Jurisdictional Regulator's participating jurisdiction* from the provision of other services by such *Distribution Network Service Providers* (the "**Transmission Ring-Fencing Guidelines**").

(c) The *Transmission Ring-Fencing Guidelines* and the *Distribution Ring-Fencing Guidelines* may include, but not be limited to:

(1) provisions defining the need for and extent of:

(A) legal separation of the entity through which a *Network Service Provider* provides *network services* from any other entity through which it conducts business;

(B) the establishment and maintenance of:

(i) consolidated and separate accounts for *prescribed services* and other services provided by the *Transmission Network Service Provider;* and

(ii) consolidated and separate accounts for *prescribed distribution services* and other services provided by the D*istribution Network Service Provider*;

(C) allocation of costs:

(i) between *prescribed services* and other services provided by the *Transmission Network Service Provider;* and

(ii) between *prescribed distribution services* and other services provided by the D*istribution Network Service Provider*;

(D) limitations on the flow of information between the *Network Service Provider* and any other person; and

(E) limitations on the flow of information where there is the potential for a competitive disadvantage:

(i) between those parts of the *Network Service Provider's* business which provide *prescribed services* and parts of the *Network Service Provider's* business which provide any other services; and

(ii) between those parts of the *Network Service Provider's* business which provide *prescribed distribution services* and parts of the *Network Service Provider's* business which provide any other services; and

(2) provisions allowing the *ACCC* or the *Jurisdictional Regulator* to add to or to waive a *Network Service Provider's* obligations under the *Transmission Ring-Fencing Guidelines* or the *Distribution Ring-Fencing Guidelines.*

(d) In developing the *Transmission* and *Distribution Ring-Fencing Guidelines* the *ACCC* and each *Jurisdictional Regulator* respectively is to consider, but not be limited to, the following matters:

(1) the need, so far as practicable, for consistency in the *Distribution Ring-Fencing Guidelines* between each *participating jurisdiction*;

(2) the need, so far as practicable, for consistency with Federal and State regulation in each *participating jurisdiction* of ring-fencing requirements of other utility businesses;

(3) the need, so far as practicable, for consistency between the *Transmission* and *Distribution Ring-Fencing Guidelines*; and

(4) the need, so far as practicable, for the *Distribution Ring-Fencing Guidelines* in each *participating jurisdiction* to be consistent with the arrangements for the *retailer of last resort* in that jurisdiction;

(e) In developing:

(1) the *Transmission Ring-Fencing Guidelines,* the *ACCC*; and

(2) the *Distribution Ring-Fencing Guidelines*, each *Jurisdictional Regulator*:

must consult with *participating jurisdictions*, *Code Participants* and other *interested parties*, and such consultation must be at least as extensive as the consultation prescribed by the *Code consultation procedures*.

(f) The:

(1) *Transmission Ring-Fencing Guidelines,* must be developed and *published* by the *ACCC*; and

(2) *Distribution Ring-Fencing Guidelines* must be developed and *published* by each *Jurisdictional Regulator.*

by no later than 1 January 1999.

6.20.3 Nominated Jurisdictional Regulators for development of guidelines

For the purposes of clause 6.20.2(a) the *Jurisdictional Regulator* for:

(a) New South Wales is *IPART* or any other person or body appointed for this purpose from time to time by New South Wales;

(b) Victoria is the *Regulator-General* or any other person or body appointed for this purpose from time to time by Victoria;

(c) South Australia will be the person appointed from time to time by South Australia;

(d) the Australian Capital Territory is the *Independent Pricing and Regulatory Commission* or any other person or body appointed for this purpose from time to time by the Australian Capital Territory; and

(e) Queensland is the *Queensland Competition Authority* or any other person or body appointed for this purpose from time to time by Queensland.

3.7.5 The Commission's findings

The current proposal whereby the great proportion of network charges will be levied on customers provides little incentive for the efficient location of investment in network or generation options. As it competes on a delivered cost basis, the incidence of network charges disadvantages embedded generation options. Nevertheless, the code recognises this deficiency and encompasses limited options to overcome this and other deficiencies in the network pricing regime (ie payments from distributors to embedded generators).

Clearly, the Commission is concerned that these deficiencies in the code may be contrary to the interests of embedded generators and the wider Australian community. However, the issues are complex. The Commission accepts the applicant's response to these concerns by inserting into the code an IPART style "with and without" test for avoided network costs.

The Commission also accepts the applicant's commitment to examine, as part of its review of transmission network pricing, negotiation guidelines, the incidence of TUOS charges and the unbundling of transmission and distribution use of system charges.

The Commission also accepts the applicant's code changes which provide the regulators of the transmission and distribution networks with the powers to develop ring-fencing guidelines for the accounting and functional separation of the NSPs. As part of developing its Statement of Regulatory Intent, the Commission has already sought public comment on the ring-fencing guidelines for the transmission networks. The Commission will use the Regulators' Forum to consult with the jurisdictional regulators in an attempt to get ring-fencing guidelines which are consistent between the electricity transmission and distribution networks in the NEM and between the other utility businesses (eg telecommunications and gas). Similarly, the Commission will also consult with the participating jurisdictions.

Part D Derogations

3.8 South Australia's network pricing derogations

3.8.1 What the applicant says

In the initial application, South Australia's transmission network pricing derogations apply for the transitional period up until 31 December 2000. The South Australian Government also sought longer term derogations which were intended to last for the duration of the access code up until 31 December 2010. The stated objectives of the transitional derogations were to allow the South Australian Government:

- to make decisions in applying the code's general principles; and
- to ensure the detailed transmission pricing arrangements are consistent with its policy for customer electricity prices.

More specifically, the transitional derogations would allow the state government to: determine the initial detailed pricing structure for the transmission network; use various measures to manage the network revenue requirements in accordance with its own transition policies; and apply their own specific criteria and methodologies (including the code's general principles for asset valuation and weighted average cost of capital) to determine a maximum aggregate annual revenue requirement. The derogations also provide for dividing the state into a number of zones, with the government determining average TUOS prices for each zone.

In the longer term, the proposed derogations would provide for uniform transmission pricing in each of a number of zones instead of the individual connection point pricing otherwise required by the code. Accordingly, an average TUOS charge within each transmission zone would be calculated, based on an aggregate of the:

- relevant revenue for all the transmission network connection points within that transmission zone; and

- related electricity quantities transmitted to all the transmission network connection points within that transmission zone.

The applicant stated that these amendments were introduced to manage the impact of cost reflective transmission pricing on customers at the extremity of the network. The applicant stated that South Australia's aim is to avoid substantial electricity price increases for these customers, as such increases would have substantial adverse economic and social impacts without any offsetting competitive benefits.

The applicant noted that while it would be possible to achieve similar outcomes through arrangements for explicit payments, the administrative costs of such a system would be significant and the payments would vary depending on location and customer details. They stated that the amended derogation provides the desired outcomes in a pragmatic, cost-effective way and is similar to the distribution pricing arrangements. While South Australia proposed to continue this approach after the transition period, there is no provision for the continued use of other mechanisms such as equalisation payments. The applicant stated that the impact of the proposed amendment is intended to apply only to the allocation of costs for the existing network and not to costs where new loads involve network augmentation.

3.8.2 What the participants say

While South Australia's transitional derogations drew little comment from participants, the proposed longer term transmission pricing derogation operating from December 2000 to December 2010 were opposed by a number of participants.

The general thrust of participant's concerns was summarised by BHP (sub. p. 8) which argued that cross-subsidies should be transparent and funded under a consistent methodology across jurisdictions. BHP also indicated that it is unclear why direct funding by government would not provide a far simpler and better-targeted approach, particularly given the small number of customers involved.

The EUG (supp. sub. pp. 2–3) also strongly opposed the derogation on the basis that it would be inconsistent with the NEM's cost reflective network pricing objectives, other jurisdictions' transmission pricing derogations and the Competition Principles Agreement of the National Competition Policy. The EUG argued that the derogation prolongs inefficient cross subsidies and further weakens locational signals for electricity producers and end users. The EUG indicated that its concerns were magnified both by the duration of the derogation, which continues well beyond the normally accepted transition period, and by the recent 're-balancing' of ETSA's asset values. The EUG claimed that this re-balancing will allow South Australian generation to compete on overly favourable terms with inter-state rivals and that it must create pressure to increase network charges on the monopoly transmission and distribution functions.

The EUG concluded that electricity users need access to efficient transmission prices and would be severely disadvantaged by this derogation and its long period of application. Consequently, the EUG argued that a better approach would be for the South Australian Government to provide transparent assistance through Community Service Obligations. In doing so, the EUG rejected the applicant's claim that the administration costs would be significant as only be a small number of customers would be affected.

In a similar vein, the ACA (supp. sub. pp. 2 & 10) considers it is outrageous for the South Australian Government to withhold its transmission arrangements until 2010, particularly given the asset revaluation undertaken by ETSA. The ACA argues that postage stamping of transmission pricing distorts economic signals and creates a barrier to entry for cogeneration and embedded generation. Further, they say this will lead to incorrect and inappropriate investment which will result in higher electricity prices than would otherwise be the case.

They argue that derogations beyond 2000 reduce the validity of NECA's transmission review and would defeat the objectives of competition policy.

The ACA recommended that the derogations should end by December 2000, and full details of the proposed pricing and access arrangements should be provided to affected parties. Without seeing such detail, the ACA is concerned that they may include bundled tariffs, constraints on bypass, network augmentation issues and other barriers to entry.

The Commonwealth Department of Primary Industries and Energy (supp. sub pp. 1–2) also argued that the transmission zones could have undesirable outcomes such as uniform transmission pricing across large areas, distorted locational signals and a misallocated resources. Consequently, DPIE suggested that the derogation should include a minimum number of zones.

3.8.3 The Commission's considerations

In assessing the NEM's proposed transmission network pricing regime, the Commission identified a number of concerns with the efficiency and locational signals associated with TUOS pricing. In part, this is due to an efficiency and welfare trade-off which allows a significant proportion (up to 50 per cent) of TUOS charges to be recovered through a postage stamp methodology which is likely to cross-subsidise rural and remote communities. In general, the Commission has accepted the merit of such a trade-off. Nevertheless, the Commission has strongly advocated exploring the use of more efficient pricing mechanisms while using alternative arrangements to meet social welfare objectives.

In its draft decision, the Commission argued that these issues are also pertinent to the proposed South Australian derogations which seek to extend the balancing of efficiency and welfare concerns in two ways. First, in terms of scope, by eliminating cost reflective network pricing methodologies and relying on average pricing for their transmission network. Second, in terms of duration, by applying this methodology for the life of the access code.

Consistent with its assessment of the NEM's transmission pricing regime, the Commission's draft decision accepted the merits of pricing approaches which attempt to balance the competing efficiency and equity objectives; in particular in the context of avoiding a price shock to certain consumers and thereby allowing a broad range of consumers to share in the benefits of reform. Consequently, in its draft decision the Commission indicated that it would be prepared to accept as part of the access code the short term South Australian pricing derogations on the basis that they attempt to balance the interests of users and the wider public over a transitional period.

However, the Commission's draft decision outlined a number of concerns with South Australia's proposed network pricing derogations which run from 2000 to 2010. In particular, the proposed derogation's use of average network prices is a further move away from cost reflective network prices which, in the case of the uniform NEM arrangements, the Commission argued are already significantly flawed in terms of the likely efficiency signals it will provide.

Moreover, in its draft decision, the Commission argued that the longer term derogations cannot reasonably be described as transitional as they institute a non-uniform approach to transmission network pricing for the duration of the access code. In this sense the proposed derogation appears to be a deviation from the various commitments made during the 1990s where COAG (1994a p.8):

> Agreed to the principles for a national competitive electricity industry of a uniform approach to network pricing …[where] this applies to such things as cost reflective and uniform pricing methodologies.

Indeed, the later COAG (1994b p.7) commitments emphasised the cost reflective and uniform recovery of the transmission networks' fixed costs whereas 'distribution system pricing could be calculated using a greater degree of averaging'.

Consequently, in its draft decision the Commission indicated that it is unwilling to accept the proposed South Australian derogation as it is a move away from a cost reflective and uniform approach to transmission network pricing. More significantly, however, the Commission argued that it does not accept that the proposed derogation is transitional and is concerned that long term derogations may establish a precedence and encourage other jurisdictions to develop non-uniform and long term derogations. The Commission believes that if such an eventuality were to occur, it would erode many of the benefits of having a single wholesale electricity market in southern and eastern Australia.

In reaching this conclusion, the Commission acknowledged the benefit in avoiding a sudden price shock for rural and remote consumers. Consequently, the Commission argued that while it favoured a transparent CSO, it would be prepared to consider the arrangements further if they terminated in 2002. Specifically, in its draft decision, the Commission stated:

> **The Commission is not prepared to accept as part of the access code those aspects of South Australia's transmission pricing regulation derogations which extend beyond 31 December 2002.**

In response to the Commission's draft decision, the BCA/EWG supported the Commission's position. In addition, the BCA/EWG argued that a new $2 per MWh levy had already been imposed on transmission prices in South Australia and that the level and distribution of network prices will blur appropriate pricing signals.

3.8.4 The applicant's response

In a letter dated 12 November 1997, the Chief Executive of the South Australian Department of the Premier and Cabinet, indicated that the Government had reconsidered its proposed derogation and had agreed to amend its derogation in relation to transmission pricing to provide a sunset clause of 31 December 2002. The Commission was also advised that South Australia is currently developing an Electricity Pricing Order (EPO) to implement the principles contained in South Australia's transmission pricing derogation. The EPO will apply from the commencement of the market until 2002. Reflecting this advice, South Australia's derogations have been changed by amending clause 2.29.2(h) and by inserting clauses 2.29.2(i) and (j).

(h) ~~clause 9.29.2 is to apply until 31 December 2000 but any requirements for specific provisions to apply after 2000 for consideration by the ACCC in the Code authorisation process will be submitted for inclusion in chapter 9 before 31 December 1996~~ Clauses 9.292(a) to (g) inclusive will cease to apply to *transmission service pricing* after 31 December 2000;

(i) after 31 December 2000 *transmission service pricing* for each *transmission network connection point* situated within a *Transmission Zone* will be determined by:

(1) aggregating the relevant revenue requirements, determined in accordance with the provisions of Chapter 6, for all the *transmission network connection points* within that *Transmission Zone*; and

(2) aggregating the related electricity quantities transmitted to all the *transmission network connection point* within that *Transmission Zone,*

and calculating an average *transmission use of system charge*. In this way, the *transmission use of system charges* for each *transmission network connection point* situated within a *Transmission Zone* will be the same*; and*

(j) clause 9.29.2(I) will cease to apply in respect of *transmission service pricing* for electricity transmitted through a *transmission network* situated in South Australia on 31 December 2002.

3.8.5 The Commission's findings

Consistent with its assessment of the NEM's transmission pricing regime, the Commission accepts the merits of pricing approaches which attempt to balance the competing efficiency and equity objectives; in particular in the context of avoiding a price shock to certain consumers and thereby allowing a broad range of consumers to share in the benefits of reform. In contrast to the earlier proposal, the South Australian derogations will only apply for the transitional period, to the end of 2002. From 2003 onwards the transmission pricing arrangements will be consistent across the NEM. Consequently, the Commission is prepared to accept as part of the access code the South Australian pricing derogations on the basis that they attempt to balance the interests of users and the wider public over a transitional period.

3.9 Victoria's network pricing derogations

3.9.1 What the applicant says

While the initial application contained Victoria's derogations, further amendments to these derogations were received by the Commission on 23 July 1997. These amendments were proposed against the background of the Victorian Government's decision to privatise PowerNet Victoria (PNV), the owner and operator of Victoria's transmission network. PNV was subsequently sold to GPU Inc, with the decision being announced on 12 October 1997.

The proposed amendments to the Victorian derogations require the regulator of transmission networks (the Commission from 1 January 2001), to continue to apply the relevant provisions of the Victorian regulatory arrangements (ie those governed by the *Electricity Industry Act 1993*, Victoria (EI Act), the ORG Act and the Tariff Order), for so long as any part of those provisions continues to apply. The Commission, as regulator, could only perform its functions under the code to the extent that they are not inconsistent with the Victorian regulatory arrangements.

The amendments to the Tariff Order extend the current regulatory methodology for PNV to the year 2002, 5 years after the expected sale of PNV. The current efficiency 'X' factor (of 1.79 per cent) is left unchanged until 1 January 2001, there is no revaluing of the PNV assets, and the specified augmentation regime is left in place until its expiry in the year 2000. For the period 1 January 2001 to 31 December 2002, a new X factor (of 11 per cent) is applied. The Victorian Government would also impose licence fees for the years 1998 to 2002, which will recoup a total of $190m.

The amended derogation also proposed that, at the end of 2002, a regulatory review would set the price path for PNV for the following five years. Under the Tariff Order, this would involve the regulator: applying CPI–X regulation; applying a single X factor for the five year regulatory period; allowing PNV to retain a portion of excess revenues achieved; limiting the value of X to ensure the regulator cannot recoup excess returns achieved in the current regulatory period in the next regulatory period; using the capital asset pricing model to estimate the weighted average cost of capital; using the 1994 Optimised Depreciated Replacement Cost (ODRC) asset valuation; prohibiting re-optimisation of the asset base; and setting out a range of matters the regulator must have regard to in future revenue determinations. The Tariff Order would also impose some limitations upon the regulator for regulatory reviews after 1 January 2008.

In support of the proposed arrangements, the applicant claimed the regulatory regime was not designed to enhance the value of PowerNet. Rather, Victoria's view was that introducing private ownership is the best driver towards efficiency and a consumer focus. For example, the changes to the Tariff Order would result in a 2 per cent reduction in electricity prices to consumers over the period 2001 to 2002. The changes do not alter the competitive elements of the transmission sector (eg the contestable nature of augmentations to the transmission system in Victoria) but would enhance the contestable nature of the transmission sector (through the abolition of the list of prescribed augmentations).

In addition, it was argued that these changes do not purport to extend the period for which the ORG would regulate transmission pricing as the Commission would regulate transmission pricing from 1 January 2000, in accordance with the present version of the code. However, the Commission will be required to apply the Tariff Order's principles rather than chapter 6 of the code, in its price determination which will have effect up until 2007.

The applicant claimed that the principles and methodologies for regulating transmission pricing specified in the Tariff Order would not be inconsistent with the principles set out in the code but rather would specify in more detail how the principles in the code would be applied in Victoria and deal with certain other matters not addressed in the code.

The applicant stated that the arrangements would limit the ability of PNV to extract monopoly rent, through the imposition of an X factor of 11 per cent in 2001 and 2002, and the extraction of $190m in licence fees for the years from 1998 to 2001. The Victorian Government's advisers have determined that the arrangements should provide PNV with a return on assets which is approximately equal to the return being earned by TransGrid in New South Wales and is comparable with IPART's recent determination of AGL's return on assets. In this context, whilst PNV's return on assets will be similar to TransGrid's, PNV is in fact exposed to higher risks as it has no control over network investment and planning functions — this is a VPX function.

Beyond 2002, the criteria for determining transmission pricing would allow PNV to earn a reasonable rate of return, based on a weighted average cost of capital formulation and having regard to levels of risk assumed by PNV and international and interstate benchmarks.

The applicant also argued that the 'CPI–X' approach to regulation provides an incentive for the regulated business to be efficient (including optimising between asset investment and operating expenditure) and requires any such gains to be shared with consumers in the long run. The proposed Tariff Order amendments set out the 'belts and braces' of implementing this approach and are designed to reduce doubt and avoid ambiguity.

The applicant stated that to maximise the incentives to achieve efficiencies it is necessary to define how the regulator will share the benefits from efficiency gains between PNV and its customers. To achieve this, the proposed amendments to the Tariff Order expressly provides for a sharing of efficiency benefits between PNV and its customers on a basis similar to the 'glide path' method used in the UK. They stated that this methodology has the greatest potential to maximise the level of efficiency gains and the speed at which such gains are achieved, thereby delivering sustained benefits to consumers over time.

3.9.2 What the participants say

The Commission received 8 submissions which were largely critical of the proposed derogations on the basis that they may encourage derogations by other jurisdictions and because they restrict the ability of the regulator to react to changing circumstances.

Precedent effect

SMHEA raised concerns over the possible precedent effect of the derogation, stating that it may induce other jurisdictions may also make similar derogations. It pointed out that the management of transmission assets will impact across borders, and such a derogation can distort the energy market. SMHEA also noted that the derogation will prolong the 'rail gauge' problems within the NEM beyond the agreed transition period.

Colin Taylor questioned the legality and degree of public interest in regulating the transmission assets in Victoria on a different basis to other states, and noted that 'it must be anticipated that accepting the proposal is likely to set a precedence for different regulatory criteria to be applied on a State by State basis.' Colin Taylor also noted that the impact of the proposals cannot be quarantined to Victoria, as the cost reflective component of transmission pricing impacts on all NEM participants to some degree. He stated that it would be preferable for a common transmission network regulation approach, with a common end date, to apply to all states in the NEM.

The South Australian Government argued that the PNV derogations would distort Victoria's transmission prices relative to other jurisdictions. It added that the effect of the Victorian derogations would be to extend the period that transmission prices in jurisdictions would remain subject to jurisdictional policies rather than being set according to a national approach. The South Australian Government considered that as long as transmission prices in different jurisdictions are subject to separate jurisdictional policies, there should be a requirement that there be no cross border cash flows for transmission pricing.

The Queensland Government stated that it was concerned over the possible interstate effects, the implications for investment and the precedent which would be established by the PNV derogations. It argued that the extension of the transition period to 2007 failed to meet either the letter of the COAG agreements or the spirit of them. The Queensland Government was also concerned that the costs of this initiative be quarantined to Victorian customers. It stated that any transfer into other states would have implications for generation investment and energy sourcing decisions. The Queensland Government had concerns over the Victorian Government's reluctance to apply the ODV asset valuation, arguing that it is unclear why revaluing the assets should be delayed until well into the next decade as this may introduce distortions between TUOS charges and generation investment.

The Queensland Government concluded that the PNV derogation should include a shorter sunset, a revaluation of assets to establish a more market oriented price for transmission to ensure investment decisions are not distorted, and a quarantining of the effects to Victoria if neither of these elements were accommodated.

The EUG stated it was most concerned that significant long term derogations in the area of transmission pricing would undermine the national market. It argued that other jurisdictions could use the derogation to detract from the NEM and National Competition Policy.

CitiPower expressed reservations regarding the derogations extending 'well beyond what might reasonably be described as a transition period'.

Capral Aluminium agreed that a transition period may be necessary, but stated it should be kept as short as possible, and that derogations should not extend beyond five years. It also raised concerns over the precedent effect of this derogation.

While not objecting to a derogation which sought to set in place well specified regulatory arrangements that deliver fair pricing outcomes, BHP noted that there was little consultation regarding the derogation and was concerned that it may set a precedent for other jurisdictions.

Regulatory flexibility

ACTEW was concerned that the Victorian proposals would impinge on the regulator's ability to improve network pricing methods, for the period up to 2012. SMHEA pointed out the derogation pre-empts the NECA review, undermining the value of the review, and prevents the regulator from applying improved transmission pricing arrangements, for the purpose of immediate windfall gain.

BHP stated that in conflict with the code provisions, the decision on transmission tariffs has been made by the Victorian Government, rather than a regulatory body, and has been made with no customer involvement and only limited consultation. BHP asked that the ACCC ensures the derogation is not incorporated into the code unless it provides for full consultation processes and information disclosure requirements, for the present period and future reviews. BHP also stressed that a review period should be no more than five years.

Capral noted the undesirability of the Victorian derogations pre-empting the Commission's processes of reviewing the transmission network pricing proposals in the code, and the NECA review to be conducted in 1998.

TransGrid asked the Commission to ensure that the asset valuation methodology, depreciation rules and other revenue determining parameters adopted in the Victorian derogation be readily developed into a uniform set of national parameters. TransGrid noted that the assertion that PNV would be provided with a return on its assets approximately equal to the return earned by TransGrid is difficult to substantiate without full disclosure of both entities financial parameters, and further points out that IPART applied a degree of judgement to the valuation of TransGrid's assets, as well as relying on other financial indicators in its pricing determination.

CitiPower, while supporting the overall objectives of the derogations, had reservations about the highly mechanistic and prescriptive approach proposed. It noted that while the proposals are not inconsistent with the code, it was concerned about the extent which the regulator would be precluded from applying alternative models of regulation which may emerge in the future. In particular CitiPower suggested that transmission networks could be better regulated by reference to general economic indicators with a reliance on bypass to ensure economic efficiency. While CitiPower supported the objective of 'fair sharing of efficiency gains' and the concept of incentive based regulation, it did not support the locking in of the mechanism, as proposed in the derogation.

The EUG argued the derogation provides for too long a period before PNV's assets are revalued. It claims that the Commission should have an opportunity to review PNV's asset valuation when it assumes regulatory responsibility, particularly bearing in mind concerns that PNV's revenue cap is already too high.

Australian Paper argued that it is 'at a loss' to understand the extent and duration of the derogations and was concerned by the request to lock in this new tariff structure for 10 to 15 years as this may lock in errors. Australian Paper was strongly of the view that regulatory reviews should not exceed five years. It further argued that the decision to have a longer period between reviews has no validity unless designed to give revenue stability for a prospective asset purchaser. Australian Paper stated that this was clearly inappropriate.

Other issues

BHP noted the licence fee arrangements, in place to prevent windfall gains of $190m to PNV, implied substantial scope for estimation error in the setting of transmission prices in the period up to 2002. It stated that there is a failure in the regulatory system whereby customers are required to pay charges based on pre-existing costings, although revised costings have been used to devise the new charging arrangements, including the extraction of the licence fee. Arrangements should be included to pass through the $190m in cost saving to end users. Given that the Maximum Uniform Tariff does not apply to a large portion of the Victorian market, BHP argued the Tariff Order should be amended to allow a reduction in transmission charges and for the distribution businesses to immediately pass through the cost savings to end users.

Boral Energy raised concerns over the imposition of a flat licence fee, stating that such a fee does not equitably meet the objective of limiting PNV's ability to extract monopoly rents from the market. Boral Energy stated that the licence fees are not cost reflective, and would distort price signals to the market, in particular disadvantaging projects such as embedded generation. BHP also had concerns regarding the treatment of embedded generation in the Tariff Order, and suggested it needed to be amended, along similar lines to the IPART proposals for the treatment of embedded generation, to address the need to share the benefits of embedded generation and establish guidelines for this process.

BHP reiterated earlier comments regarding information disclosure, and the need for the code to provide for a review of information disclosure provisions in the light of experience. In particular, a reassessment would be required where customer participation in the revenue capping process is ineffective. BHP requested the ACCC to review PNV's asset base, given its importance and as it would be locked in until 2007.

A further concern raised by BHP was the return on capital allowed to PNV, and benchmarking the return to the AGL level in New South Wales. BHP was concerned that access charging in the gas industry limits the extent to which competition will develop in that industry, but also established a poor precedent for other infrastructure sectors. BHP suggested that the ACCC should review the return implicit in the PNV pricing arrangements, and use international benchmarks as a guide.

CitiPower argued that there was no strong reason evident for protecting the asset values from review until 2007, and noted the proposed approach will extend the complications and disadvantages faced by co-generation in relation to transmission charges.

Hazelwood Power argued that the combination of the code and the Tariff Order would provide no commercial drivers to enable proper allocation of risk on a negotiated basis. It noted that unless the accountability of PNV for the performance of its assets in delivering competitive energy to the market is strongly emphasised immediately, the privatisation of PNV is likely to make the development of a firm access regime difficult or impossible in the future.

Australian Paper supported the concept of a CPI–X approach, but argued that as the proposed X is a large figure, this implies the current revenue cap is too high and should be reduced now. It added that the original asset valuation for PNV was obviously incorrect, a point supported by the Victorian Government decision to reduce the asset value but claim the resulting revenue surplus as a licence fee. Australian Paper claimed that PNV charges are high as a reality test has not been undertaken. It recommended the code should require benchmarking against international equivalents.

3.9.3 The consultant's view

With funding from the Victorian Government, the Commission contracted the National Economics Research Associate (NERA) to evaluate and provide commentary on the proposed regulatory framework for Victoria's electricity transmission network. This summary is taken from NERA's report which was publicly available on the Commission's web site during the course of the Commission's assessment of the access code.

Precedent effect

Consistent with many of the participants, NERA observed that Victoria's proposals would impose state based regulatory arrangements until at least 2007, thereby delaying the introduction of nationally uniform transmission regulation. Further, the proposed Victorian regime would effectively operate in perpetuity, unless the code specifically rules out the mechanisms used in the Victorian instruments (eg ODRC valuation and the glide path), which would leave little prospect of a truly uniform national transmission regulation.

NERA indicated that the Victorian proposals would pre-empt the NECA pricing review and NERA also stated that other jurisdictions are unlikely to accept proposals from the NECA review which would lead to customers in one state paying for transmission services in another state, unless the basis for regulation is the same. NERA concluded that the likely effect of the Victorian proposals is abandonment of a national transmission pricing regulation regime.

Regulatory flexibility

In its report, NERA stated the proposed Victorian methodology prescribes certain elements which limits the regulator's flexibility. The proposed amendments specify the glide path methodology. NERA states that in using this methodology it will be important to distinguish between the extent to which future determinations of allowed revenue will be influenced by efficiencies achieved, as opposed to exogenous influences or to decisions which belong to the regulator. Where above normal returns are due to good fortune or any other exogenous parameters, it would be more efficient for price to be allowed to reflect costs more quickly (ie P_0 adjustment). Therefore the case for mandating the use of a pure glide path needs to establish that the likelihood of the good fortune/exogenous factors occurring is small and/or their impact is inconsequential. NERA states that a more mainstream view is that while a perfect analysis is never possible, the potential magnitude of these factors may make them too important to ignore by mandating a specific form of glide path. This position is reflected in submissions received from Capral, SMHEA, CitiPower and Australian Paper.

A further consideration is that the main opportunities for 'gaming' in reporting of past costs is: in relation to whether expenditure is reported as either operating or capital; the extent to which costs are taken into account in one year as opposed to the next; and cost allocation/transfer pricing between regulated and unregulated parts of the business. The BHP submission strongly emphasised the likelihood of information inaccuracies impacting on any determination made by a regulator. While NERA recognised the practical limitations to the extent and longevity of 'gaming' by these means, the existence of a glide path increases the risk and inevitability of making incorrect judgements which are part of the price-cap determination process. Based on UK empirical evidence, NERA also observed out that the greatest risk of getting a price determination wrong is at the time of privatisation.

NERA also noted that the recontracting risk must be considered in the political environment and a mandated glide path may increase the regulatory re-contracting risk, if locked in profits were publicly perceived to be too high.

With regard to asset valuation, NERA echoed many of the participants' concerns when it stated that it is important to recognise just how crucial the capital cost-related assumptions are. Aside from whether or not the proposals will deliver higher prices than desirable from an economic efficiency perspective, the sensitivity of PNV's required revenue to these regulatory parameters significantly increases the risk of locking in inappropriate returns under the mandated glide path methodology.

NERA noted that prescribing the application of the ODRC approach can also set up incentives for over investment (same as under rate of return regulation). A practical impact of this is illustrated in the Ewbank-Preece report on asset management strategy where their advice to PNV was to keep up their investment on the basis that it brings additional revenue. Further, the mandated application of the ODRC approach appears to allocate some stranded asset risk to PNV. NERA raises this concern as PNV does not have control of network augmentation nor of the intensity of network use — the main sources of asset stranding risk. As key network decisions are made by VPX, the cost/risk of asset stranding should ideally be reflected in the decisions which VPX makes. It would be sensible to be clarify the risk allocation of asset stranding between VPX and PNV.

NERA expressed the view that specifying the Capital Asset Pricing Model (CAPM), to determine the allowed rate of return for PNV, though current best practice, is unnecessarily restrictive given increasing uncertainty about its validity. Although the proposed approach is not uncommon for asset intensive, regulated industries, NERA stressed the importance of the capital cost assumptions. In particular, while NERA considered that the conceptual basis for the ODRC valuation is sound, it felt that the practical application of the ODRC valuation results in an upward bias and that the ODRC estimate for PNV is overstated.

Moreover, NERA questioned several of the key assumptions in determining the weighted average cost of capital (WACC), including:

- Does the asset beta reflect the particularly low risk nature of PNV's business, relative to other network utilities (ie if revenue is protected by the regulator)?
- Should the risk free rate be determined on today's rate (which is what bidders will actually pay) rather than on a long term average?
- Does imputation credit utilisation raise consistency issues with respect to foreign owners compared to local owners?
- Is the 60 per cent gearing assumption low given PNV's risk profile compared with other utilities?

NERA concluded was that the concepts applied and the assumptions reached, at each step in the WACC calculation, have erred towards higher rather than lower estimates.

Furthermore, from 1998 onwards the proposed revenue determination does not require any real reduction in operating and maintenance costs. In relation to capital investment the capital spending plans have not been developed on a needs basis which is a fundamental requirement of good utility regulation. NERA states the evidence suggests that the allowed level of capital expenditure is unlikely to bear any relation to that which an efficient operator would look to incur.

In summary, NERA's conclusions regarding the proposed Victorian arrangements were in line with many of the views of participants, when it questioned whether the PNV regulatory proposals:

- are overly prescriptive;
- allow for subtleties and judgements which are required; and
- will achieve the objectives of making customers better off and reducing the likelihood of regulatory recontracting.

NERA also observed that preventing developments in the application of principles, for example by over-specifying a particular methodology, on the back of enhanced knowledge and experience, can be counter productive. It must be recognised that consistent application of principles will not always result in the same answer or revenue determination methodology. For example NERA supported the use of 'glide path' as a regulatory tool, but did not support mandating a specific form of glide path for use at all future price determinations, as the Victorian proposals have done.

Other issues

NERA argued that competition in related markets will be affected by both the overall transmission revenue, and by the structure of transmission prices. Therefore to the extent that location-based transmission pricing is not possible, competition in the generation sector will continue to be distorted. As is the case at present, remote generators will not face the true costs of their location decision.

NERA's analysis also suggests that PNV's total revenue will be higher than necessary to cover efficient costs (including a return to the owner). This will provide incentives to avoid the costs of the transmission network (eg through uneconomic duplication, bypass and increased incentive for alternatives to networks such as greater generation capacity).

3.9.4 The Commission's considerations

In terms of selling a public utility and gaining the efficiency improvements this can generate, the Commission's draft decision recognised that there was some merit in the Victorian proposals. The Commission argued that, at the time of the sale of PNV, the national market institutions, processes and regulatory regime were, and are still, in their formative stages. This lack of certainty may have resulted in the Victorian Government achieving a sale price for PNV which was lower than could otherwise be expected. Consequently, the Commission concluded that it would be it is reasonable for the Victorian Government to seek to remove any unnecessary uncertainties and thereby achieve full value for its transmission network.

Moreover, the Commission recognised some merit in seeking to use best practice regulatory mechanisms which encourage utilities to achieve efficiency improvements and to share these gains between the utility and consumers. Traditional rate of return regulatory approaches have been rejected in the code and in the Victorian proposals as they are heavy handed and are biased as they encourage utilities to invest in capital equipment.

Incentive regulation attempts to overcome the heavy handed concerns. In the draft decision, the Commission recognised that the proposed Victorian variation of incentive regulation (ie the glide path) is more sophisticated than normal. In particular, it attempts to improve the balance of incentives for PNV to undertake regular maintenance as against capital investment and to remove any incentives for PNV to delay the timing of any non-capital efficiency improving programs. For instance, in the absence of a glide path approach, a utility may be encouraged to delay implementing a costly program of rationalising administrative, operating and maintenance costs until just after a rate review so they can enjoy the benefits of lower costs for a full rate determination period. The glide path approach attempts to bring forward any such programs and allow the benefits to be shared between the utility and its customers over a number of rate determination periods.

Despite the objectives and the likely benefits, in its draft decision the Commission argued that Victoria's proposed derogations need to be viewed in a wider context than simply in terms of their impact on sale price and the interests of the future owner of PNV. In particular, the Commission emphasised that it has to examine the proposals in the national context as well as being satisfied that they are in the public interest and in the interest of access seekers. In its draft decision, the Commission indicated that its public consultations revealed a number of inter-related concerns. First, in attempting to establish regulatory certainty prior to the sale of PNV, Victoria's proposed derogations would have introduced non-uniformities into the transmission regulatory regime for an extended period of time. Second, Victoria's proposed approach could well have established a precedent and provided scope for other jurisdictions to also move away from earlier commitments concerning a single electricity market in southern and eastern Australia. Third, key parameters in determining transmission prices (ie assessments of asset values and risk) would have been locked-in to provide certainty for the purchaser of PNV, but it was unclear whether these parameter values were accurate and therefore whether the proposed arrangements would be in the interests of access seekers or in the public interest. Each of these issues is addressed in turn below.

A further issue arose regarding the legal framework surrounding the regulatory regime and the mechanism by which the Commission (as regulator) could enforce the provisions of the Victorian Tariff Order and licensing arrangements.

Transitional arrangement

In its draft decision, the Commission indicated that its major concern regarding the proposed arrangements related to the period for which the derogation would apply and the lack of a clearly specified end date. The proposed arrangements could be considered as dealing with several distinct periods: up until the end of 2000; 2001 to the end of 2002; 2003 until the end of 2007; and 2008 and beyond. The Commission argued that a transition period of around 5 years, until 31 December 2002, to be adequate in terms of the need for the jurisdictions to make incremental adjustments to the full NEM arrangements.

Consistent with the Commission's assessment of South Australia's proposed transmission pricing derogations, the Commission did not consider that the Victorian derogation could truly be considered a transitional arrangement (ie they allow for the Tariff Order to be applied in perpetuity, unless the code specifically rules out the proposed mechanisms). Therefore, while preferring that derogations were generally not made, in the draft decision the Commission indicated that it would be willing to accept an arrangement that extends to 31 December 2002.

The Commission maintains its view that a transition period until the end of 2002 will provide an appropriate balance of the interests of the facility owner, access seekers and the broader public interest. The Commission believes that a five year transition period goes a long way to meeting the applicant's desire for the derogations to provide a benefit by introducing regulatory certainty for the buyer of PNV, without introducing any detriment to consumers. It also addresses the concerns of interested parties that whilst agreeing with the need for regulatory certainty, to maximise the benefit from PNV's sale price, the period for which the arrangements extend (and the detail of the arrangements) may enable the owners of PNV to extract monopoly rents at the expense of consumers. Further it was submitted that the period of regulatory certainty proposed was far in excess of that given to other buyers of newly privatised assets, both in Victoria and overseas.

The Commission's consultants, NERA, also pointed out that the long time period involved may in fact increase regulatory uncertainty, if there were political or public perceptions that the returns generated under the proposed arrangements were too high. Therefore, while the Commission agreed that while there may be some measure of public benefit in removing unnecessary uncertainty for potential buyers, it did not agree that the proposed arrangements would have achieved that goal, nor that it was necessary for uncertainty to be removed to the extent proposed. Indeed, in its draft decision, the Commission indicated that it had serious concerns about the likely impact of the long term application of Victoria's proposed derogations not only for electricity users in that state but for the likely success of the whole NEM reforms. Therefore, on the basis of these concerns and a view that derogations should only apply for a transitional period, in its draft decision the Commission stated that:

> **The Commission is not prepared to accept as part of the access code those aspects of Victoria's transmission pricing regulation derogations which extend beyond 31 December 2002.**

Precedent effect

In the draft decision, the Commission also argued that, to a large extent, the proposed derogation appears to be a deviation from the various commitments made during the 1990s where COAG agreed to a uniform approach to network pricing in the NEM. These commitments were particularly strong in terms of transmission pricing. In this context, the transmission networks are particularly important for the efficient operation of the wholesale market where generators in each of the jurisdictions will be competing against each other on the basis of merit order dispatch.

On the basis of the Commission's public consultations, the Commission had significant concerns regarding the likely impact of the proposed Victorian derogation on the implementation of the NEM. The Commission noted, and in general agreed with, the concerns raised by interested parties, and in particular the other jurisdictional governments, regarding the impact of this derogation on the implementation of uniform transmission pricing regulation in the NEM. For instance, a number of governments had indicated that, if the proposed arrangements were implemented, they would seek to quarantine the financial impacts of Victoria's transmission network thereby ending the concept of a seamless transmission network for the NEM.

Moreover, the Commission believed there was a substantial risk that, in accepting the proposed Victorian arrangements, other jurisdictions might then have come forward with long term derogations for transmission pricing, or other aspects of the code, with respect to their own State based arrangements. Indeed, Queensland, in their draft derogations provided to the Commission, explicitly stated that they would only comply with the provisions of clause 6.2.1(a)(5) of the code (commencement of transmission pricing regulation) if all other participating jurisdictions also comply with that clause.

The implication of non-uniform transmission price regulations is that the NEM will effectively operate as linked state markets, and unless the state based arrangements are amended to include locational signals, continuing distortions will flow into the generation sector of the industry.

Regulatory lock-in

The Commission's further concern with the longer term application of the proposed derogations related to their prescriptiveness and inflexibility. Victoria's transitional transmission regulatory arrangements, specified in chapter 9 of the code, and also in the terms of the Tariff Order, were very prescriptive in relation to the pricing and methodology to be applied by the Regulator through to 31 December 2007. Additionally, the Tariff Order sought to impose on the Regulator a number of ongoing restrictions with respect to reviewing the revenue control arrangements which take effect after 31 December 2007 (Tariff Order clause 3.7.1).

As was observed by many of the participants, the Victorian derogation pre-empts the NECA review of network pricing, and by prescribing the methodologies to be applied, restricts the regulator from applying possible improvements in pricing methodologies that may be developed in the future. As such the Commission believed that the arrangements would prevent the regulator from applying best practice regulation to the transmission network in Victoria.

The Commission was aware of the need for the price regulation to include some incentives to drive efficiency gains, and hence the need to allow the regulated business to keep the benefit of some of those efficiency gains. This was balanced by the need to limit the ability of monopoly businesses to extract rent from users of their facilities. However, the Commission was not convinced that the glide path methodology prescribed under the proposed Victorian arrangements would always be the best option for achieving the balance of maximising incentives for efficiency gains and maximising consumer welfare. As with other aspects of the code's transmission network pricing regime, the regulator should have sufficient flexibility to react to changing circumstances within the context of broad principles.

Similarly locking in the asset values until the end of 2007 would be a concern, because irrespective of their veracity when determined in 1994, it is unlikely that the use of the network will remain such that the valuation would still be correct, in either 8 years (2002) or 13 years (2007). Changes in use, population shifts, development of embedded generation, network bypass, augmentations and competing interconnectors may all occur in such time frames, and all will impact upon the valuation of the PNV asset. Consequently, the Commission maintains its view expressed in the draft decision that it would not accept a derogation which prevents the Commission from taking the option of revaluing the assets at the time the Commission takes over as regulator.

The Commission remains unconvinced regarding some other aspects of the proposed regulatory arrangements, including the assessment of the riskiness of the business as reflected in the WACC and implied rate of return on assets, the level of capital investment under the arrangements, and the depreciation arrangements.

3.9.5 The applicant's response

In response to the authorisation draft determination and access code draft decision, the Victorian Government indicated that it accepted the Commission's condition so that the Victorian transmission pricing derogation will end exactly on 31 December 2002.

Specifically clause 3.6 of Victoria's Electricity Supply Industry Tariff Order states that clauses regulating PowerNet will either cease on 31 December 2000 or on 31 December

2002. Moreover exept as otherwise contemplated by the tariff Order, the regulator cannot determine Powernet's charges prior to January 2003.

3.9.6 The Commission's Findings

Currently, the national market institutions, processes and regulatory regime are still in their formative stages. In these circumstances, the Commission sees merit in the Victorian transmission pricing derogations which attempt to provide regulatory certainty over a transitional period, up until the end of 2002, and at a time when PNV has recently been sold to a private sector investor. Consequently, the Commission is prepared to accept as part of the access code the Victorian transmission pricing derogations on the basis that they attempt to balance the interests of the new network owners, users and the wider public over the initial stages of the Natinal Electricity Market.

While the Commission engage a consultant to examine the detail of the Victorian derogations, the Commission has not formed a view on the various parameters which will comprise the regulatory regime for PNV up until 31 December 2002. Nevertheless, the Commission anticipates that the issues raised in the NERA report, and other matters dealing with the regulatory regime, will be addressed when the Commission performs its role under the code as the transmission network regulator.

4. Connection, use of system and disconnection

The main objective of any access arrangement is to facilitate connection to, and use of, natural monopoly facilities. In doing so, an access arrangement will stimulate competition in markets. Consequently, the electricity access code's connection, use of system and disconnection procedures are central to its ability to generate the benefits from electricity reform.

Achieving these benefits requires streamlined and transparent connection procedures that do not unnecessarily create additional entry barriers for new generators, new customers and/or new technologies. Nevertheless, sound procedures are required to ensure the integrity of transmission and distribution systems are maintained. In this way, electricity can continue to be supplied according to known and acceptable performance and safety standards.

In many circumstances minimal entry barriers, yet sound access procedures, are competing objectives which need to be balanced when creating an access regime. This balancing act is made even more complex because a new connection may have unintended consequences for existing network operators and users (the reverse also applies as existing networks and users can impact on new entrants). The access code's connection, use of system and disconnection procedures sets out how these competing demands will be treated in the NEM.

This chapter assesses the merits of the code's handling of this balancing act through its connection, use of system and disconnection procedures. In performing this assessment, and on the basis of the information presented, the Commission has aimed to identify procedures which may significantly impinge on the interests of network service providers, network users and the Australian community more generally. The Commission has also attempted to identify deficiencies which limit the benefits which are intended to flow from the access code. In performing this assessment, the Commission has adopted a somewhat cautious approach given the importance of reliable and safe electricity supplies and the evolving nature of the NEM and its associated access regime.

The chapter commences with a brief overview of the main elements of the code's connection, use of system and disconnection procedures (section 4.1). The Commission then analyses the code's: connection negotiation procedures (section 4.2); connection equipment design and technical standards (section 4.3); inspection, testing and commissioning requirements (section 4.4); and disconnection procedures (section 4.5). Augmentation and network planning are examined in chapter 5.

4.1 Overview of connection and use of system arrangements

In the electricity market, connection to and use of the physical high voltage and distribution networks (poles, wires, transformers etc) as a transport system for electricity will be managed separately from the financial trading of the electrical energy which travels on those networks. The code aims to create a workable, non-discriminatory right of access to the physical 'natural monopoly' network which enables users to participate in the competitive electricity market. The connection procedures seek to provide a uniform, step-by-step process for connecting new customers, managing extensions to the physical grid as well as specifying equipment standards and testing. These procedures are governed by a set of connection principles, objectives and obligations (see Box 4.1). In bringing these procedures together in the access code, the applicant (sub. p. 216) argued that:

> It needs to be recognised that arrangements and procedures for connection to transmission and distribution networks have existed for many years but these differ between jurisdictions and between Network Service Providers. One objective of these provisions is to provide a common set of procedures for connection to simplify entry for parties seeking access.

Connection to a network at the wholesale level typically will be covered by a connection agreement between an NSP (transmitter or distributor), a generator or a customer (eg a mine or industrial plant). Provided other users are not adversely affected, the connection agreement may override code provisions and must include:

- the legal and financial terms and conditions of the connection;
- service standards for ongoing use of the network;
- technical specifications for the type of connection involved and its operation; and
- details on payment for connection and network service.

The connection procedure is designed so that, wherever possible, the applicant for connection needs only to deal with a single NSP — ie a 'one-stop shop' philosophy. At the same time the provider must inform the applicant of other NSPs who need to be involved and of the contestability of any extension work associated with a new connection. The code does not preclude the possibility of network connections being competitively provided. The code also proposes that a central body, separate from the individual NSPs, should manage network planning for the shared or 'global' network.

The connection arrangements cover several facets, namely:

- connection procedures, including modification of existing connections;
- design of connection equipment;
- inspection, testing and commissioning of connection assets;
- operation and maintenance responsibilities; and
- disconnection and reconnection.

Each of these issues is discussed in more detail below. The dispute resolution process, an adjunct to connection negotiation, is discussed in chapter 7 in the broader context of the access code's dispute resolution processes.

4.2 Connection negotiation procedures

The access code's requirements for gaining connection to the transmission and distribution networks can be divided between process issues and technical requirements. This section examines the processes whereby users (ie generators and loads) can gain access to electricity networks. The technical requirements are examined in section 4.3 while connection arrangements for grid augmentation and inter-connections are discussed in chapter 5.

4.2.1 Issue for the Commission

The Commission's assessment of the access code's connection arrangements focuses on their likely impact on entry barriers and spillover effects. The assessment criteria of particular importance addresses the issue of how the connection arrangements:

- promote the public interest by not unnecessarily adding to entry barriers which would reduce contestability in other markets;
- protect the legitimate business interests of:
  - the existing network owners and users from potential spillover effects from the operation of new connections; and
  - new connectors from potential spillover effects from the operations of existing network owners and users.
- may affect or be affected by such matters as:
  - legislation and policies on ecologically sustainable development;
  - social welfare and equity considerations, including community service obligations;
  - legislation and policies on matters such as occupational health and safety, industrial relations, access and equity;
  - economic and regional development, including employment and investment growth;
  - the interests of consumers generally or of a class of consumers;

— the competitiveness of Australia; and
— the efficient allocation of resources.

Entry barriers in the form of technical expertise or financial resources can exist in any industry and generally are of little concern to the contestability of a market when they apply equally to incumbents and new entrants. However, they may be a concern where the entry requirements for new participants are larger, more onerous or more time consuming than for existing network users. In terms of the network connection procedures, the Commission has focussed on whether the connection procedures create an entry barrier and, if so, whether these entry barriers are non-discriminatory between existing, new and potential entrants and between differing technologies. The Commission has also examined whether the connection procedures can be justified in terms of a defined objective and, if so, do the benefits of the connection procedure outweigh any costs. The Commission has paid particular attention to the potential spillover effects as they can have serious ramifications for the health, safety and property of all parties connected to the grid and on the ability of the system to deliver network services.

4.2.2 What the applicant says

In addition to a general obligation to follow the code, each network service provider is also obliged to submit an access undertaking, conforming to the code, for the Commission's acceptance. In certain circumstances NECA can exempt network owners from the requirement to submit an access undertaking.

The applicant (sub. p. 55) outlined that the principle intention for the code's connection arrangements is to:

> ... limit the ability of the Network Service Providers to use their natural monopoly power to the detriment of network users and provide adequate levels of services to network users.

The code seeks to achieve these objectives through a series of arrangements which detail connection principles, objectives and the connection processes. In general, the code proposes that an offer to connect must be made to a connection applicant where an application complies with the code requirements (for further details see Box 4.1). The applicant indicated that (sub. p. 216):

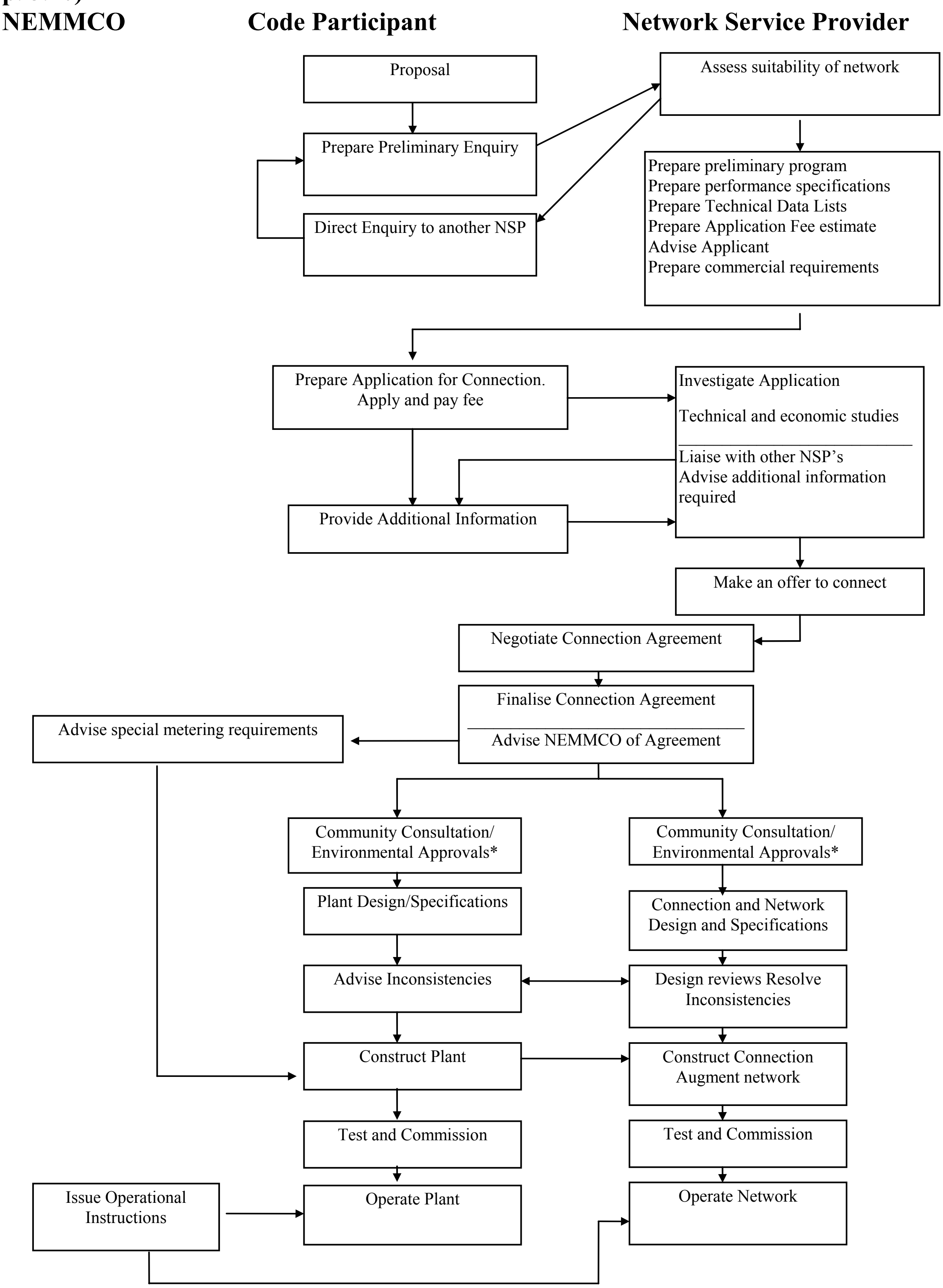
> The major principle of the connection requirements provisions is that a party is to be provided physical access to a transmission or distribution network on a fair and reasonable basis provided that the connection arrangements do not materially or adversely affect the levels of service and quality of supply to other network users.

The completion of certain stages of the connection process are subject to time lines:

- within ten days of receiving a connection inquiry, the NSP must advise whether another NSP would be more appropriate for the connection;
- within two weeks of receiving the inquiry, the NSP must notify the applicant of:
  - other parties involved in the relevant network planning and/or service;
  - the need for any additional agreement with any of those parties;
  - whether the connection will involve contestable services;
  - a preliminary program of work and time lines to finalise the connection.
- within four weeks of the application being lodged, the NSP must advise of further information required to process and finalise the application, including technical standards, prudential requirements and application fees;
- the NSP must make the offer to connect within the time period specified in the preliminary program, unless otherwise agreed;

- after the connection agreement has been finalised, the NSP advises NEMMCO of the agreement and NEMMCO must advise within 20 days whether the metering installation is acceptable;
- where the connection may adversely affect the network and the applicant has provided information for assessment, the NSP must within 40 days advise of any deficiencies in the design of the facility.

FIGURE 4.1 ACCESS CONNECTION PROCEDURES (based on code diagram, p. 5.10)



*In accordance with the relevant laws in each participating jurisdiction.

Note: This is a generic representation of the major steps required to establish a connection. They may be varied to suit the circumstances of the application.

Box 4.1: Overview of connection principles and obligations

The code establishes that:

- connection to the national grid must be consistent with the principles that:
  - ⇒ all code participants have the opportunity to connect;
  - ⇒ the terms and conditions for network connection and providing network services be set out in the connection agreement;
  - ⇒ code participants benefit through national grid costs and reliability;
  - ⇒ code participants openly communicate about network connections subject to security of confidential information;
- code participants are obliged to operate their equipment in accordance with relevant laws, code requirements and good electricity industry practice;
- network service providers are obliged to:
  - ⇒ meet the relevant code requirements, including registering with NEMMCO and submitting an access undertaking to the ACCC;
  - ⇒ comply with system performance and quality standards in the code or in a connection agreement (depending on the impact on network security and quality), such as:
    - operating their network in accordance with NEMMCO instructions;
    - managing and maintaining their network to meet agreed capability, specified fault levels and minimum interruptions; and
    - advising on expected interruptions and restoring agreed capability as soon as possible following an interruption.
  - ⇒ process connection applications and enter into connection agreements as required by the code, including:
    - co-ordinating design aspects of connection equipment;
    - participating in network modelling and planning with other NSPs and the Inter-regional Planning Committee; and
    - inspecting, testing and commissioning facilities and equipment;
- network customers and generators are obliged to:
  - ⇒ ensure that their facilities always comply with the connection requirements and conditions specified in the code or a connection agreement (depending on the impact on network security and quality), including operating facilities and equipment in accordance with NEMMCO and system operator directions;
  - ⇒ apply to connect via a connection agreement in accordance with the code, including:
    - complying with reasonable requirements for the design of equipment; and
    - permitting and participating in inspecting, testing and commissioning facilities and equipment;
  - ⇒ give notice of voluntary disconnection as required by the code.

If the connection applicant accepts the offer to connect, the parties will enter into a connection agreement which will specify the terms and conditions for connection.

The applicant stated (sub. p. 220) the connection requirements are based on the principle of commercial negotiation and are synonymous with the concept of 'light handed regulation' as:

- NSPs and parties seeking access must negotiate a connection agreement that:
  - meets the needs of the connection applicant; and
  - does not adversely or materially affect the levels of service and quality of supply received by other network users.
- regulatory intervention should only be required in the event of an access dispute or where a party believes they have been discriminated against.

Amongst other things, the applicant indicated (sub. p. 132) that in negotiating the terms and conditions for connection:

> Responsibility for the planning and design of connection assets will be essentially driven by the customers who are receiving the service. Most decisions can be made by them with respect to the level of service including the capacity of the transmission or distribution network without impacting on other participants.

The applicant (sub. p. 217) argued that the connection requirements do not unduly impinge on the legitimate business interests and investments of the NSPs as the network standards are a continuation of pre-existing standards and because NSPs will be involved in: coordinating the design of connected equipment; planning and developing the network; and inspecting, testing and commissioning connected facilities.

The applicant (sub. p. 218) indicated that the approach to providing access and connection to the network is in the public interest as it has been designed to ensure that, from a participant's perspective, a clear and unambiguous framework is established within which negotiations with the NSP can take place. Such negotiations would cover the terms and conditions for a connection facility. An important aspect of providing access would be to maintain the integrity of the network to provide the quality of service required by other users. In addition, wherever possible the code introduces competition into the connection arrangements by allowing users to apply to connect to more than one NSP.

The applicant (sub., pp. 218–9) argued that connection arrangements are in the interests of access seekers as: NSPs are bound to process access enquiries; the procedures for seeking access are clearly defined; and the connection conditions can be negotiated to meet the specific requirements of the access seeker.

In addition, the applicant (sub. p. 221) argued that these arrangements give participants full control over network service options, with scope to make appropriate trade-offs between cost and the performance and reliability of the network service provided, for instance:

> New entrants can seek access to a transmission or distribution network and will be able to obtain access at defined (fair and reasonable) prices which accurately reflect the cost of providing the necessary assets to allow connection at the specified capacity and level of performance.

The applicant also stated (sub. p. 222) that the code places extensive information disclosure requirements on the NSPs to meet the needs of connection applicants. These provisions include information to be disclosed for:

- a connection inquiry and application (including technical details) and for consultation with other affected code participants;
- the design of connection equipment, as well as inspecting, testing and commissioning facilities; and
- disconnection or reconnection of a participant to a transmission or distribution system.

These information disclosure provisions have been designed to ensure that:

- the party seeking connection is fully aware of the information that is required to enable connection to be established; and
- the NSP can provide access to a transmission or distribution network without materially or adversely affecting the levels and quality of service received by other network users.

The applicant also addressed (sub., p. 238–239) the status of bypass in the code:

> The code neither encourages or discourages bypass; it simply permits it. The code seeks to ensure that the transmission pricing and regulatory arrangements do not unduly encourage new investment in facilities which substitute for or duplicate existing facilities, where the incremental costs of the new facilities is greater than the avoided incremental costs of existing facilities. ... This approach is intended to ensure that bypass of existing networks only occurs where bypass is in the public interest (ie where bypass is the least-cost option from a total societal perspective). It is considered unnecessary for the code to explicitly mandate bypass...

The applicant also argued (sub. pp. 158–9) that the code provides the option of 'firm access' arrangements for generators. NSPs are to negotiate in good faith to provide compensation in the event that a generator is constrained-off because the level of service and capability of the network is not consistent with the terms of the connection agreement. They are also required to provide adequate information to support negotiations and use best endeavours to meet each generator's request, consistent with good industry practice and related decisions on augmentations and other firm access agreements. NSPs can also negotiate similar arrangements with customers and other NSPs but they are not obliged to do this:

> A major concern for generators arises from the possibility that such an outage could coincide with a high pool price incident in the energy sub-market. This would expose generators with contracts for differences in the energy sub-market with very high difference payments.
>
> The compensation provisions in clause 5.5(f) are to enable the generator and the Network Service Provider to come to an appropriate risk sharing arrangement...
>
> ... compensatory arrangements applying to generators are neither necessary nor applicable to energy customers. It is submitted that this arrangement provides public benefit because energy customers and generators are provided with incentives to behave in an appropriate manner to maintain a secure power system at the same time as they are provided with economic signals to which they can each sensibly respond (pp. 158–59).

4.2.3 What the participants say

Nearly all submissions considered that the code's connection procedures adequately protect the legitimate business interests of the NSPs, with some suggesting the process is biased too much in the providers' favour. However, one issue of concern to the Queensland distributor SEQEB (sub., p. 1) was that it may not always be possible for the NSP chosen by an access seeker to process a connection application.

However, most comments on the connection procedures focussed on the problems for users (especially new entrants) of access services. These concerns covered a cross-section of connection issues including the need for negotiation guidelines, information requirements for small access seekers, rights to bypass, firm access arrangements and technical requirements.

While generally endorsing the principle of negotiation, submissions from a broad range of participants also expressed concern over the possible abuse of monopoly power due to the relative strengths of users and providers in the negotiation process.[1] For instance, the Energy Users Group (sub., pp. 74ff, 82) agreed that the code caters well for access providers in terms of connection procedures but queried whether the code adequately met the public interest and the interests of persons requiring access.

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1 Business Council of Australia; Australian Paper; Boral Energy; Integral Energy; Yallourn Energy; National Farmers Federation; Australian Chamber of Manufactures; Hugh Outhred; Michael Gunter. Similar concerns were raised earlier in 1996 in response to the ACCC Issues Paper on the Code.

The EUG argued that as the bargaining position of grid operators and end users 'is quite uneven', negotiations should be subject to guidelines similar to those developed by IPART. The Business Council of Australia (sub., p. 21–27) supported these views with reports from their members which indicated that NSPs are not negotiating in practice and this is exacerbated by the code being silent or ineffective on the disclosure of adequate information to enable effective negotiations.

More fundamentally, the joint submission from the five Victorian distributors (sub., pp. 20-21) said the connection process required significant revision to become a clear and effective blueprint for connection to distribution networks. Specifically they said:

- the code needs to reflect the fundamental difference between procedures for large and small scale connections, particularly in regard to:
  - the vast amount of information required;
  - the relevance of notification and consultation requirements;
  - the degree of flexibility in approach to different categories of customer;
- undue pressure is placed on customers to provide information which they may not be able to provide or which may not be relevant; and
- the procedures duplicate environment and planning conditions already imposed by local laws.

Other submissions said the detailed requirements favoured large scale generators at the expense of smaller, non-dispatchable plants, including some renewable energy forms and more distinction is needed regarding the size of units, sufficient to protect other participants and in proportion to the impact on system security.[2]

Bypass is also an important issue for network users. The Business Council believes the code is biased against the option of bypass thus seriously limiting the ability of users to rely on the threat of bypass as a viable alternative in their negotiations with providers. It also claims that the application of the same network pricing rules for bypass as for network service providers takes away the financial benefits of bypass. Similarly the Australian Cogeneration Association (sub., pp. 8, 17; report, pp. 12–14) emphasised the need to introduce contestability through the option of bypass:

> We believe that the best approach to bypass is to ensure that the rights to such facilities are made explicit in the code and clear to all. Experience of our members supports the view that creating a right to build bypass or inset networks of itself provides a powerful incentive for fairer negotiations between parties even if the facilities were not built. We would be concerned if significant layers of regulation, conditions or costs were imposed on the rights of bypass of a cogenerator as this would present a barrier to entry that would adversely affect project economics, particularly in the case of smaller cogeneration schemes (sub., p. 17).

The Association said it was willing to participate in developing guidelines for bypass.

All of the participants who advocated an explicit recognition of bypass saw it as a key competitive discipline on the monopoly position of network service providers:[3]

> The code should not preclude other participants from building extensions to the network or bypassing part of an existing network. Where possible the network owners should be exposed to competition.

Submissions from several generators and others also requested an explicit obligation on network service providers to offer firm (ie reliable) access to network availability.[4] The

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2 Greenpeace; Snowy Mountains Hydro-electric Authority; National Farmers Federation.

3 Business Council of Australia; Australian Cogeneration Association; Snowy Mountains Hydro-electric Authority; Energy Users' Group; Boral Energy; Australian Paper; Australian Chamber of Commerce and Industry; Australian Chamber of Manufactures; BHP; Delta Electricity; Capral Aluminium; Lend Lease.

submissions said that obliging network service providers to offer firm access (as distinct from the present requirement to negotiate in good faith) would create incentives to maintain network capability. They want the pricing to be fair, non-discriminatory and transparent, with one suggestion being an annual tender of firm access contracts . It was suggested that firm access should be available to customers, interconnection projects and load management options.[5] The Snowy Mountains Hydro Electricity Authority (SMHEA) also (p. 4) proposed that rules determining regions, losses, inter-regional hedging, firm access and constraint payments should be viewed in conjunction with network pricing and connection arrangements:

> Ideally the set of rules should ensure that there is no systematic bias in favour or against inter-state trade versus intra-state trade and trade within one location versus another relative to what should occur on an economic basis. The current rules are deficient in this respect.

Several submissions highlighted other issues that are likely to make connection applications and negotiations difficult for access seekers, namely:

- the overall approach of the procedures is unduly complicated and onerous to participants;
- connection in the NEM will reflect a range of jurisdictional differences that continue beyond the transition period and depend on a vaguely defined standard of 'good industry practice';
- technical requirements may be used to hinder fair negotiation and limit new entry and competition;
- the description of contestability in connection to networks is unclear and again negotiations in this area can be aided by a set of guidelines.

4.2.4 The consultant's views

In addition to the views of participants, the Commission engaged Western Power to review the technical aspects of the access code. In relation to the code's connection negotiation procedures, Western Power (pp. 24–28) considered that the connection application rules strike an appropriate balance between the interests of NSPs and participants, and that there are adequate safeguards in place to ensure efficient connection investment decisions by NSPs. Their report argued that the minimum terms and conditions set out in the code schedules are reasonable and of the kind to be expected for connection agreements.

While acknowledging that the code was a complex document, Western Power argued that this was inevitable given the complexity of the national grid and the associated technical requirements. Nevertheless, Western Power argued that the code's connection inquiry and offer process would be improved if:

- one NSP were responsible for all liaison between the code participant and other NSPs, to avoid confusion and potential disputes;
- there were more discretion in deciding what information is needed to technically assess a proposal;
- existing agreements were honoured when affected by someone else's new connection, unless the parties agree otherwise or the change is to ensure the safety, quality and reliability of supply;

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[4] Firm access in this case means an intra-regional hedge which insures against the risk of network constraints within a region preventing generators (or customers) from taking advantage of favourable spot prices. In other words, the hedge works as a proxy for continued access to the regional spot price at traded volumes. Network reliability is discussed below at 4.3.3 and 4.3.4.

[5] Snowy Mountains Hydro-electric Authority; Boral Energy; Hazelwood Power; Yallourn Energy; Macquarie Generation; Tasmanian Government; Greenpeace; .

- any new agreement should not, as far as possible, impose a barrier to entry to future participants;
- random auditing could be used to ensure NSP information requirements are not unduly discriminatory; and
- an NSP should be able to offer alternative ways of establishing the connection.

It also suggested that renegotiation of a connection agreement (especially one affecting existing participants) may be contentious because participants have to accommodate the risk of future change, even though they have signed an agreement.

4.2.5 The Commission's considerations

The Commission recognises that the code's standardised connection procedures provide a number of benefits for both access providers and users because it can:

- establish a public and common reference for connection procedures and standards;
- minimise time and resources spent on identifying and negotiating relevant issues, information and procedures; and
- provide a benchmark to correct problems and resolve disputes.

Moreover, as the connection requirements will be negotiated on a case-by-case basis, they are capable of being flexible enough to meet the specific requirements of individual NSPs and access seekers.

However, the risk remains that users may be denied their rights of access to electricity networks by unresolved negotiations. Users may also be effectively denied their rights to access by protracted and/or costly negotiation procedures. Consequently, the code's connection negotiation model needs to ensure there is an appropriate balance in the relative negotiating positions and be simple enough to meet the diversity of customer needs and to promote competition. The Commission's concern is how effectively the code procedures achieve an appropriate reconciliation of interests in this respect.

To a large extent the code and existing laws provide a range of options that individual users and NSPs can employ to correct or resolve problems encountered in negotiating and managing a connection agreement. For instance:

- The code includes dispute resolution procedures which involves objective criteria and scope for conciliation and/or arbitration by an independent yet well-informed disputes body (for a further discussion see chapter 7 of this report).
- The code includes inspection rights and NECA enforcement procedures which act as both deterrents and remedies against inappropriate behaviour.
- The Commission can apply to the Federal Court to enforce the NSPs' access undertakings under Part IIIA of the Trade Practices Act. The Commission can also prosecute those participants which breach the unauthorised competition provisions of Part IV of the Act.
- While it may be costly and outcomes somewhat uncertain, commercial arbitration and common law enforcement are options where a connection agreement already exists.

Despite these remedies, participants expressed continuing concerns as to the recognition of rights to bypass, difficulties in reading and using the code, negotiating advantages NSPs' derive from their monopoly position, the desire for firm access and the potential for technical standards to delay or prevent new entry are serious issues in terms of the key rationale of Part IIIA (ie the availability of access to promote competition).

The Commission believes that, although the interests of NSPs are crucial, its assessment of the code must also attach some priority to the primary users of the network. In particular, as network users will generate many of the benefits of electricity reform by increasing competition (eg between generators) and by allowing market forces to encourage innovative solutions to traditional problems (eg embedded generation and demand side responses). Moreover, when NSPs commence negotiations with users for connection, augmentation or related network services, the NSP is likely to possess advantages related to their monopoly position, economies of scale and scope and position as the incumbent (eg accumulated information, reputation and skills).

The Commission is also mindful of the public interest in maintaining and improving electricity networks in ways that are efficient, conducive to competition and heeding social, environmental and workplace responsibilities. The Commission is alert to the fact that the interaction of these factors is complex and may at times encompass conflicting interests that cannot always be resolved to everyone's satisfaction.

In its draft decision, the Commission indicated that although it was satisfied with the overall framework of the connection arrangements, it considered that amendments were needed on key issues, namely bypass, interpretation of the code and firm access.

Bypass of the network

Submissions advocating bypass saw a definite need to have a viable, negotiable alternative to using the existing monopoly provider's network in appropriate circumstances. Without such a right users fear access conditions will be dictated by the NSP and they will face exploitative prices which may even be beyond the threshold of the stand-alone cost of bypass. They see a right to insist on bypass as a means of disciplining the power of NSPs and an opportunity for contestable entry into both the provision of network services and participation in the market.

There appears to be a strong basis to the participants' arguments that without an explicit right to bypass a network, access seekers have very little bargaining power in negotiating with a network monopoly. Indeed, without a guarantee of bypass option the NSP could be viewed as possessing an exclusive franchise. This is clearly inconsistent with the code's principles of contestable network facilities. It is also inconsistent with the bypass arrangements for gas pipelines in the proposed national gas code arrangements.

However, establishing an efficient set of arrangements for bypassing electricity networks is not straight forward. For instance, if network charges were subsidy free (ie based on the stand alone costs plus some contribution to common costs) then the incentives for bypass would be efficient; that is, bypass would only take place in those circumstances where constructing a stand alone facility is the most efficient option. Yet, as was discussed in chapter 3 of this report, network charges are unlikely to be subsidy free. Network costs will be allocated on the basis of cost reflective and postage stamp methodologies, where the postage stamp component is likely to involve cross-subsides from major metropolitan centers to rural and remote communities. Consequently, network charges will tend to encourage network bypass in major metropolitan centres so network users can avoid contributing to the rural and remote community cross-subsidy. Conversely, network charges will discourage bypass in the rural and remote communities.

So that bypass does not result in users duplicating network facilities in order to avoid a 'tax', there should be some scope in the code to require the users of bypass facilities to continue to contribute to the 'tax' which supports the rural and remote cross-subsidies. Clearly, such an arrangement would be messy and this complexity would be avoided if network charges were subsidy free. Nevertheless, for the time being, jurisdictional governments have adopted the current approach in order to balance equity and efficiency objectives and this added complexity may be necessary.

In addition to these issues, a range of other considerations would also have to be addressed if the bypass facility was reconnected into the wider electricity grid. For instance, network and connection charges would have to be negotiated, including in those circumstances where the network provides standby or backup services in the case of equipment failure or maintenance shut downs in the bypass network. The bypass network would also have to comply with a range of other requirements such as the code's technical requirements for system security and connection (eg testing and inspection) as well as the licensing and other requirements under the relevant jurisdictional laws.

In light of these considerations, the Commission in its draft decision argued that NECA should include in the code an explicit right for users to bypass electricity networks. However, the above discussion suggests that more work is also needed to explain how bypass will work in practice, how it will mesh with other aspects of the code and how it will account for the interests of users, providers and the public. Consequently, to ensure that these arrangements are efficient and do not adversely impact on inter-connected networks and users, the code should allow regulators or jurisdictional governments to develop guidelines to govern the bypass arrangements. Specifically, in the draft decision the Commission stated that:

> **Chapter 5 of the code must explicitly recognise the right of third parties to bypass the network, include guiding principles and, in a process involving the Australian Competition and Consumer Commission, require jurisdictional governments and regulators to develop guidelines to address the complex issue of achieving efficient bypass.**

Nearly all submissions at the pre-decision conference and afterwards supported an express provision allowing bypass by third parties of existing network. However, opinions differed as to whether the implementation of bypass should be subject to any efficiency or similar criteria.

Network service providers and others[6] voiced concerns about the code allowing for inefficient bypass and duplication of assets. In particular, they emphasised that:

- the incentive for bypass is created by distortions in network pricing, especially where averaging and maximum tariffs result in prices that are not cost-reflective;
- providers, particularly distributors who are obliged to maintain averaging, cross-subsidies and maximum tariffs, will find it very difficult to accommodate significant bypass within these pricing restraints;
- even outside such restraints, bypass could result in the remaining network customers paying more to prevent the stranding of existing assets;
- users exercising a right to bypass should still contribute to subsidies within the network pricing arrangements;
- bypass to non-contestable customers should not be allowed to undermine agreed transition arrangements; and
- third parties who bypass the network should register under the code as network service providers and be required to provide an access undertaking.

Customers and user groups[7] supported an explicit provision allowing bypass, seeing it as a countervailing factor in negotiations with monopoly network service providers. They expressed concern about conditions or guidelines governing the implementation of bypass that may have the effect of unduly restricting its use. They propose that either:

- there be no restrictions on the negotiation of bypass arrangements apart from commercial incentives and reasonable technical conditions; or
- that any guidelines focus on procedures for the efficient negotiation and implementation of bypass, leaving it to the investors to judge whether or not bypass is economically efficient.

Hugh Outhred noted that it would be unwise to rely too heavily on bypass to control NSP behaviour.

[6] TransGrid; Solaris; CitiPower; Eastern Energy; Powercor; SEQEB; Incumbent New South Wales DNSPs; South Australian Government; SMHEA; energyAustralia.

[7] EUG; BCA; Australian Cogeneration Association; BHP; Australian Paper; Cadia Mines; Ampol.

A related issue raised by network users was the scope of both rights of access and bypass under the code, with particular focus on access to easements. At the pre-decision conference TransGrid indicated that easements were not part of the code because they are covered by jurisdictional laws. Cadia Mines advocated that rights of access, including procedures for resumption and compensation of freehold, should be the same as for statutory bodies. The EUG requested that, before approving the code, the Commission ensures that the exclusion of easements from the code will not diminish contestability.

In response to these concerns, the Commission requested the applicant to amend the code so it was clearer that the scope of the access code relates to the facilities of the NSPs in relation to the services of conveying and controlling the conveyance of electricity. Consequently, it would be clearer that the access code does not cover any other services that could be provided by an NSP's facilities.

In addition, the concerns raised by both users and providers regarding implementation of bypass within the context of existing regulatory arrangements support the Commission's view that guidelines on bypass are required. These arrangements presently cover such diverse issues as regulated tariffs, cross-subsidies and statutory easements.

Difficulties in reading and using the code

Participants argued the code is a complex document which may act as a barrier to entry to smaller or inexperienced market participants. The Commission believes that it should not be unexpected for the code to be complex as many of the issues it addresses are of a highly technical nature. Moreover, given its legal status, the code has to be written in a way for it to be interpreted and enforced with clarity and certainty. Finally, the design and content of the code attempts to balance:

- new rights and obligations of participants in a restructured industry and market including the right to be connected upon request;
- the need to reduce NSPs' existing monopoly and information advantages;
- the safety of life, health and property; and
- the duty of NSPs and system operators to maintain the network.

Consequently, the Commission understands the difficulties which were encountered in dealing with these wide-ranging concerns in a clear, systematic and integrated manner, which is capable of being adapted to the diverse needs of users and providers. The Commission also recognises that in developing the code widespread consultation and numerous trials were undertaken with a view to producing a workable set of arrangements. Moreover the code has an in-built change process to enable ongoing reform and NECA is being advised by a Market Liaison Panel created to review the code's implementation.

At the same time, difficulties in reading and using the code are a major theme of most submissions, especially from users and users' groups. Similarly, the information burden the code places on small users is seen to be unmanageable and inflexible. Unless addressed, these difficulties could delay and hinder the participation of those small users in the access arrangements and the electricity market.

A useful proposal has been for a range of organisations (eg NECA, regulators etc) to publish additional guidelines suited to particular classes of user, technologies and/or applications. The aim of such guidelines should be to simplify the procedures for participants and to clearly identify the minimum amount of information and consultation required to comply with technical standards and code objectives. Moreover, NSPs could develop forms to assist users to prepare the information required for connection applications. The Commission thinks such guidelines, if well written, will not detract from the integrity of the code as the standard reference on the electricity market. Instead they ought to be a useful way of providing a plain English explanation of the code provisions that are most relevant to individual users and providers.

The Commission maintains the view expressed in the draft decision that it would be useful for facility owners and network users if these guidelines identified explicit discretions within the connection process that minimise the burden of paperwork and compliance on small and new participants.

More generally the code's review and changes processes need to give priority to improving the ability of users, especially small users, to manage the connection process in an effective, efficient manner. The code is likely to be an evolving document, with ongoing clarification and development to make the code more understandable and appropriate to current and future industry needs. It would appear that the code change process goes some way to providing an opportunity for such refinement to the code. Nevertheless, in the draft decision the Commission stated that:

> **To improve the efficient operation of the access code's procedures, the National Electricity Code Administrator should simplify and refine the code on an on-going basis, including developing guidelines, forms, diagrams and charts in order to enable small and new users of the network to interpret and apply the code.**

In response to this recommendation, submissions from users stressed the need for guidelines to facilitate the negotiation of network access and augmentation. The EUG calls for a set of guidelines (particularly principles) for the negotiation of connection and avoided network costs. Similarly, the ACA advocates embedded generator guides and negotiation guidelines particularly for connection, standby and avoided network costs.

Firm access

The Commission is aware that firm access is much debated and the current code provisions are the latest of several versions. In addition there has been a profound change in the commercial relationship between generators and transmission networks, as well as others in the industry, as a result of structural separation and privatisation along with the wholesale markets and access arrangements. Previously, firm access arrangements were determined by administrative decisions, often internalised in a single organisation or at least in a public sector framework. In future, the risks of operating generation units and underwriting new plant will be determined on the basis of commercial negotiations and incentives. The code provides some guidance on these matters, but the issue is complex and is also linked to decisions on regional boundaries, price differentials and network constraints. Rules governing the treatment of constraints within and between regions should aim to minimise any bias for one type of trade over another.

Although NSPs are not obliged to provide firm access in every case, the code includes a set of obligations in terms of negotiation, information and compensation arrangements. Similarly, generators are limited to their maximum power input and any arrangements must account for its impact on firm access for other generators.

Improved cash flow provides a major incentive for both generators and NSPs to bargain firm access. Generators are either compensated when constrained-off or are able to bid unconstrained (because of network improvements) when spot prices are favourable; and NSPs derive revenue from the sale of firm access rights which can partly fund those network improvements. Consistent with these incentives, the code provides for maximum prices for a defined (minimum) network service. It also envisages that participants can negotiate discounts for the defined service or can negotiate for an improved level of service but at a higher price. In this context it should be remembered that generators pay little in the way of TUOS charges.

However, both NSPs and generators claim some network problems (including some constraints) occur for reasons neither can control, yet there are common benefits in managing this residual risk. The Commission notes there is nothing in the code which would prevent generators, NSPs or both insuring against this risk externally, in addition to negotiated firm access arrangements. The cost of this cover will be guided by commercial assessments of risk and may provide useful information for assessing the cost of alternatives (eg investment in network enhancement). However, firm access and insurance arrangements will make the relationships between generators and NSPs more complex due to the sharing of risk.

Consequently, the Commission believes that while the code is largely neutral on firm access arrangements, the code includes sufficient flexibility for generators and NSPs to negotiate access arrangements (including firm access) which is in the commercial interests of both parties. Nevertheless, if the generators' concerns are realised, and the NSPs refuse to negotiate terms and conditions, then at that stage it may be appropriate for the Code Change Panel to consider alterations to the code which provide NSPs with additional incentives or obligations to provide firm access arrangements.

NECA accepts the need to keep firm access arrangements and the extent of their use under review as part of its annual reviews of code operations.

In contrast to these views, a number of submissions voiced concerns with the potential for discrimination in the allocation of firm access. Related to this is the possibility of one or a few generators dominating firm access arrangements in a regional market, thereby excluding others from that market.

While these concerns may have some basis, they are not sufficient to reject the notion of firm access. For instance, the firm access arrangements could be for a limited period. Moreover, discrimination between suppliers or customers may not be detrimental to competition or access, and may be based on legitimate efficiencies. However, if this is not the case, there may be a breach of Part IV of the Trade Practices Act where existing remedies apply (eg where discrimination is symptomatic of anti-competitive misuse of market power, substantial lessening of competition, exclusionary provisions or blatant disregard for interests of either users or the public).

Alternatively, when firm access arrangements are likely to involve both anti-competitive discrimination and public benefits, the relevant access undertaking could be varied (subject to the Commission's approval) and/or the relevant conduct submitted for authorisation by the Commission to avoid challenge under the Act.

A related issue is the issue of network reliability and the achievement by NSPs of a suitable standard of performance in the operation of network and connection assets. For example, the firm access arrangements discussed above seek to establish a range of financial incentives to ensure such performance. Other relevant concerns in this context are those raised in regard to the provision of system security services by NSPs and the ability to include ancillary services in connection agreements. These issues are discussed further in 4.3.3 and 4.3.4.

Based on the range of views and concerns of a broad cross section of parties involved in the electricity industry, the Commission in its draft decision stated that:

> **At an appropriate time after the commencement of the market, the national Electricity Code Administrator should review the arrangements for firm access so the code change processes can consider any amendments required to introduce further incentives and/or obligations regarding the provision of firm access.**

Submissions received since the pre-decision conference highlight the complexity of firm access indicating that it cannot be dealt with in isolation. It has ramifications for other concerns such as the identification and management of network constraints, the potential to commercialise ancillary services, compensation for both constrained-on and constrained-off generation, the scope for generators to pay transmission charges and the obligations and incentives on network service providers to deliver identifiable standards of service.

For instance, at the pre-decision conference and in subsequent submissions[8], generators argued for a significant strengthening of the firm access provisions in clause 5.5. They requested that NSPs be obliged under the code to negotiate and offer firm access hedge arrangements with compensation whenever generators are constrained-off the network. They argue that, under the present provisions, NSPs presently negotiate from a monopoly position and thus have no incentive to bear extra risk of network constraints and the adverse impact these constraints can have on access to favourable pool prices. The incumbent generators argue that NSPs should offer a choice of access arrangements including, but not restricted to, firm access. They also argue that obliging NSPs to offer firm access would be the most efficient allocation of network risks to the party most able to bear the risks and would reinforce locational pricing on different parts of the network, thus removing uncertainty for new generators connecting to the network.

At the pre-decision conference the ACA commented that generators would be entitled to firm access if they paid for it, referring to the fact that generators (in contrast to loads and embedded generation) are currently not liable for transmission charges. Submissions from user groups and customers[9] propose that generators should pay TUOS charges and negotiate firm access in their connection agreements with their network service providers. The ACA argues this will create commercial incentives for generators to monitor, and providers to improve, network performance. It also argues that the exemption of generators from network pricing means users and consumers will ultimately bear the capital cost of transmission.

Exemptions from access undertakings

While NECA may exempt NSPs from the code obligation to provide an access undertaking, it should be noted that such exemptions will not replace the coverage of significant infrastructure by Part IIIA and hence the risk of declaration of services not already covered by an undertaking. The Commission understands that in practice these exemptions will only apply to small networks (eg high-rise buildings and caravan parks) which do not meet the declaration criteria.

On the issue of the code and undertakings operating until 2010, the Commission is conscious of participants' concerns that the status of a protected provision may detract from competitiveness and flexibility. In practice, however, the Commission and the applicants are well aware (not the least due to the authorisation and access process) that the code will be an evolving instrument requiring regular review and changes. In this context, the Commission considers that clause 1.12 operates only to protect the provision that:

- the code sets out the terms and details of access arrangements; and
- the access code and access undertaking expire on 31 December 2010.

Therefore the provisions of the access code or access undertaking in the code are not protected, and any changes, for example arising from the NECA review, will not be prevented by the protected provision status of clause 1.12. The Commission believes that the protected provision status of the access undertaking and the duration of the protected provisions provide a degree of certainty to market participants.

4.2.6 The applicant's response

8 Yallourn Energy; Optima Energy; Macquarie Generation; Loy Yang Power; Hazelwood; SMHEA.

9 Australian Cogeneration Association; EUG; BCA; Ampol; Incumbent New South Wales DSNPs; energyAustralia; Australian Paper.

The applicant has accepted the Commission's proposals relating to bypass arrangements. First, the applicant has amended the code by inserting new clause 5.1.2(c):

> (c) Nothing in the code is to be read or construed as preventing any person from constructing any network or connection assets.

Second, the applicant also agreed that the review of transmission and distribution pricing will include a more detailed consideration of bypass, including the issue of efficient bypass, and will consider the content of guidelines. In particular, clause 5 of Terms of Reference state that the review will specifically consider:

- the basis for an appropriate framework to govern the right of third parties to bypass transmission and/or distribution networks.

Third, the applicant has amended Schedule 5.8 to make it clear that the access undertaking, to be submitted by all NSPs, relates to the network services of conveying or controlling electricity and not to other services which could be provided by the networks' facilities. In particular clause 4 of Schedule 5.8 has been amended to state:

> On registration by *NEMMCO* as a *Network Service Provider*, the *Network Service Provider* undertakes to provide access to the *network services* of its *transmission networks* and *distribution networks* on the terms and conditions set out below.

And the definition of network services in chapter 10 of the code has been amended to state:

> *Transmission service* or *distribution service* associated with the conveyance, and controlling the conveyance, of electricity through the network..

In response to the Commission's concerns about code complexity, the applicant indicated that NECA will review a broad range of technical standards within two years of market commencement.

The applicant accepted the Commission's proposal to review the arrangements for firm access and have included this within NECA's review of transmission and distribution pricing arrangements. Specifically, clause 5 of the Terms of Reference states that the review will specifically consider:

- whether there is a need for a framework for firm access and, if so, appropriate arrangements.

4.2.7 The Commission's findings

In general the Commission considers that the connection negotiation process promotes the interest of facility owners and network users in that it: gives appropriate emphasis to the customer exercising their initiative to establish access to the network; documents in detail the procedures, standards and information required to negotiate a connection agreement; employs time lines and other obligations to ensure connection negotiations progress to a suitable outcome; and allows for review of critical decisions affecting participants' interests.

Despite this, the Commission shares a number of the participants' concerns in relation to the relative negotiating position of NSPs and access seekers and the information burdens the code's connection procedures places on smaller access seekers. Nevertheless, the Commission believes that the impact of these concerns will be ameliorated by the inclusion into the code of a right for participants to bypass networks and by a clarification of the services covered by the code. These concerns will also be further addressed by the NECA review of transmission and distribution pricing which, amongst other things, will specifically consider the frameworks governing bypass and firm access.

While the Commission supports this approach, it believes the bypass guidelines should aim to accommodate the diverse interests of facility owners, network users and final consumers by:

- setting out effective negotiation and implementation procedures;
- defining conditions for efficient investment in bypass within evolving network pricing arrangements; and

- clarifying the status of bypass facilities with regard to access undertakings and jurisdictional planning laws.

In addition, the Commission believes NECA should devise a program of review to test the effectiveness of the connection process to:

- distinguish the information requirements that are essential for all connections and those that apply only to large users or complex applications;
- give NSPs a clear discretion (exercised upon an applicant's request) to exempt small users from information and other procedural requirements; and
- minimise the burden of compliance for users and providers.

Moreover, the Commission maintains its view that through the various reviews, NECA in collaboration with NEMMCO, should attempt to simplify the code where practicable and develop user guides with a view to addressing the concerns of smaller market participants.

4.3 Equipment design and technical standards

Chapter 5 of the code and its schedules detail the information NSPs require from:

- participants designing or obtaining equipment to connect to the network; and
- all participants in order to forecast and review the use of the total network.

The schedules specify the technical and performance standards relevant to each type of network participant (ie NSPs including distributors; generators; and customers) unless varied in connection agreements. The content of these schedules largely mirror the system security requirements of the access code. To assist in the assessment of the connection arrangements, the Commission engaged Western Power to provide a review of the code's technical requirements including those which apply to network connection. The Commission's assessment of the technical requirements for power system security and metering are contained in chapter 6 of this report.

4.3.1 Issue for the Commission

The design, technical and operating standards specify a range of basic requirements which together represent an up-front cost for both users and NSPs in establishing and operating viable connections, maintaining the integrity of the system and enabling users to participate in the wholesale or retail electricity markets. At the same time, standardising the connection requirements attempts to streamline the process to ensure the connected equipment and systems are compatible.

In examining these standards and the nature of the associated rights and obligations of NSPs and users, the Commission's approach has placed particular emphasis on:

- the public interest in both:
  - promoting competition in markets by minimising the cost of complying with the technical standards underlying network operations; and
  - safeguarding the collective interests of all users and providers in their safe, efficient and effective use of the network system;
- the interests of individual users in terms of their investment in connection assets, their location on the network and their capacity to supply or receive electricity via the network;
- the interests of individual providers in terms of preserving the value of their investment in the network system; and
- the existence of long-established technical standards and practices which are supported and regulated by access regimes in each State and Territory.

The Commission's analysis of the standards seeks to determine whether the cost of compliance and/or enforcement of the standards will:

- create any unjustified costs or inefficiencies for participants;
- unduly favour some participants relative to others;
- lead to inconsistent or discriminatory treatment of participants; or

- otherwise hinder access without yielding any net public benefit.

4.3.2 What the applicant says

The design, procurement and construction of plant and equipment must be based on the technical requirements in the code and relevant connection agreement. In reaching an agreement, the applicant and NSP must ensure:

- design information and drawings are inspected and approved prior to manufacture of equipment; and
- inconsistencies and design deficiencies are negotiated and resolved.

The NSP shall use best endeavours to advise of inconsistencies but bears no responsibility for failure to advise of a design deficiency.

The planning process for the shared network has been based on a model of co-ordination between NSPs, generators and retailers, involving shared forecasts, planning reviews, analysis of expected developments of the shared grid, consultation with affected participants, reports on planned augmentations and their cost. This is discussed later in chapter 5 on augmentation.

The applicant says that the procedures and technical aspects of the code (see Box 4.2 for more detail) are required to ensure the safety of the electricity industry, workers and the general public. Also, inappropriate connection of equipment can reduce the quality of supply to other network users. The integrity of the network is maintained by the provisions and schedules dealing with:

- the design of connected equipment;
- planning and developing the network;
- inspecting and testing equipment;
- the power of NEMMCO to disconnect customers;
- network performance requirements; and
- connection requirements for applicants.

NSPs, customers and generators are all required to maintain and operate equipment that is connected to the network in accordance with the relevant laws, the code and good industry practice.

Box 4.2: Technical and performance standards

The schedule for *NSPs* has the 'satisfactory operating state' of the network as its basic reference and then defines the various performance measures required in different operational categories to deal with departures from normal conditions. These are set out as objectives or targets for such matters as:

- power transfer capabilities;
- frequency variations;
- voltage control;
- system stability;
- fault clearance times;
- load shedding capability;
- line ratings; and
- remote control and monitoring technologies.

In terms of performance outcomes, the schedule for *generators* focuses on the continued supply of power in extreme or worst case scenarios. Targets based on electrical engineering standards include matters such as:

- automatic control of active and reactive power;
- reactive power capability;
- automatic disconnection and other protection features;
- governor systems and responses;
- transformers;
- shut-down, restart and loading rates; and
- communication systems; remote control and monitoring technologies.

Generators have specific obligations to negotiate and co-ordinate with their NSP on design and layout of plant, protection and control measures, insulation, fault levels and clearances, and communications. The schedules also classify the different types of data required for connection and planning purposes.

Operational standards for *customer* connections are specified for such areas as:

- compliance with relevant Australian design standards;
- protection settings;
- power factor requirements;
- load balancing and shedding;
- voltage fluctuations and harmonics; and
- substation design.

The access code (schedule 5.1) defines the power system performance standards to be maintained by NSPs when designing connection facilities for customers and generators. The code sets out performance standards for NSPs, particularly in the technical schedules. Schedule 5.1 obliges each NSP to:

- fully describe the quantity and quality of network services which it agrees to provide to a person under a connection agreement in terms that apply to the connection point as well as to the transmission and distribution system as a whole;
- ensure that the quantity and quality of those network services are not less than a level of service which complies with the criteria in schedule 5.1, recognising that levels of service will vary depending on location of the connection point in the network.

Network services which are not covered by schedule 5.1 are to be described in terms that are fair and reasonable. These criteria may be varied in a connection agreement but not if there is an adverse effect on other participants. Schedule 5.6, which covers the terms and conditions of connection agreements, also refers to 'details of any agreed standards of reliability of transmission service or distribution service at the connection point or within the network.'

These performance standards are also to be maintained by the NSPs as they design augmentations in response to an increase in customer loads or new generation plant. Similarly, the conditions for connecting generators and customers (schedules 5.2 and 5.3), reflect the unique physical differences involved in supplying electricity to, and consuming electricity from, a network.

The code also specifies procedures for negotiating connection and design covering matters such as minimum information for each stage, for example preliminary enquires should identify plant (including type and configuration), location, maximum capacity, production/consumption rates and technology. Connection points are to be defined in the connection agreement. The schedules also classify the different types of data required for connection and planning purposes.

In support of the code's connection arrangements, the applicant (sub. p. 217) argued that the legitimate business interests of the NSP is protected by ensuring that the network's pre-existing service standards carry over into the National Grid. Moreover, any variation from these standards is by negotiation between the NSP and the network user.

In a similar vein, the applicant (sub. p. 218) argued that the code's connection arrangements promote the public interest by setting technical standards to ensure that the power system operates safely and that it transports electricity according to acceptable quality standards. At the same time, the standardisation of connection requirements attempts to streamline the process to ensure compatibility of connected equipment and systems. The applicant submitted (sub. p. 156) that:

> These technical standards despite their different impacts on suppliers and customers operate in the public interest because without them the power system will not operate safely to convey electricity to customers to an acceptable technical quality of supply. These standards are similar in their economic effect as those applied to many markets. The standards help establish a degree of confidence in the quality of the commodity and in so doing reduce the

Table 4.1: States and Territory technical derogations

State	Transmission		Distribution	
	Expiry date	**Derogation**	**Expiry date**	**Derogation**
Victoria	31/12/2002	Generators, smelters and other traders exempt from code where it conflicts with contracts. Generator performance must follow Victorian requirements. Networks: Automatic reclosure requirements and target fault clearance times agreed by VPX and PNV will replace relevant code provisions.	Indefinite	ORG regulates access, connection and augmentation for all networks according to ORG (not code) procedures.
New South Wales	Power Trader exemptions cease when supply agreements end.	Power Traders exempt from code where it conflicts with supply agreements. New South Wales operating standards continue as regional procedures after market commencement.	Not applicable.	Not applicable.
South Australia	31/12/2002.	Generator performance must match South Australian requirements and are exempt from specific code performance requirements.	Until code changes deliver equivalent benefits to South Australia.	Particular facilities may be exempt from NEMMCO. Existing connection design requirements under existing agreements are deemed acceptable for code purposes.

> transactions costs of supplying and purchasing electricity both at the wholesale and retail level.
>
> The applicant states that the integrity of the networks are also preserved by the access code's requirements relating to system security, system reliability and the duties of NEMMCO.

Table 4.1 indicates how the jurisdictions will replace the code technical standards with their local variants for the transition period.

The applicant points out (sub. p. 156–7) that there is flexibility in implementing the technical standards as:

> Not all existing facilities connected to the networks in participating jurisdictions comply with minimum technical standards in chapter 5. These differences arise because:
>
> - technology and technical standards have changed over 40 years;
> - it has not made commercial sense for an existing facility to upgrade its facility when the current facility is not compromising the quality of electricity received by other users.

The applicant states that the public interest of customers and generators would not be served by an arbitrary requirement to upgrade existing facilities to new technical standards when there is no appropriate financial incentive to do so.

4.3.3 What the participants say

TransGrid (sub., p. 6) stated the code's quality requirements are the minimum necessary for the safety and security of the system and to protect customer and network equipment and similar to standards used world wide. TransGrid saw sufficient scope to vary connection design as long as it does not affect the quality and reliability due to others. The requirements are adequate to ensure continued viability of network businesses and provide levels of supply and reliability as at present.

The consultant's report stated that, in general, the technical requirements will not:

- impose any unnecessary barriers to those seeking entry to the market and/or access to the wires infrastructure;
- place any burden on new providers beyond those necessary to ensure an adequate level of power system security;
- create any advantage/disadvantage for current network providers, provided power system security and quality of supply are not adversely affected; or
- discourage network investment or impede the future development of the market.

The consultants conclude the connection requirements are consistent with the need to ensure an adequate level of power system security and generally consistent with accepted industry practice. However, they also pointed out several areas where the code could be improved by:

- providing more specific information on some requirements (eg protection settings; duplicate protection; stability; design standards) to avoid disputes over interpretation;
- further highlighting special conditions or exemptions applying to co-generators, embedded generators and alternative generators; and
- achieving uniformity between jurisdictions on such issues as the inclusion of three phase faults as credible contingency events for lines operating at or above 220kV.

The Business Council of Australia (sub., p. 27–29) said their members' experience indicates that technical standards will favour incumbents over new participants. Moreover, because of derogations, technical standards will differ between States which:

> ...can impose serious impediments to the entry of new competitors and to the operation of efficient competitive markets. They also violate the general principle of mutual recognition of standards applying on one State by the other States. Differing technical standards can be readily used as a subtle barrier to entry by the existing incumbents.

These differences included:

- more stringent security standards for new entrants;
- excessively long fault clearance times;
- excessive delays due to assessment of technical requirements; and
- unrealistic requirements for load balancing.

The Council called for common minimum technical and security standards and their publication together with supporting information.

Network reliability

Submissions from a number of generators expressed the view, based on experience, that the standards of performance set for NSPs in the code will not be adequate and that there are few incentives or obligations in the code for NSPs to provide reliable network or connection assets. They believe the code arrangements insulate NSPs from the market and other commercial risks created by unreliable or constrained networks and yet allow them to collect revenue irrespective of their performance. For instance, Hazelwood Power (sub. p. 2) argued:

> The market is defined as occurring at a notional regional node and the network provides the only means of physical transport to and from this node. Participants are rightly obliged to pay for this service. However, failure of this transport capability causes pool and contract risk for participants and in some cases extreme financial detriment — yet the code requires only 'reasonable endeavours' performance from the network for the regulated charge.

These submissions contrasted the performance requirements on NSPs with the technical obligations on generators, particularly small and alternative energy plant, which they see as very onerous.

An obligation to provide firm access (discussed earlier in 4.2) is advocated by these participants as one way of insisting on improved reliability. They also seek a more direct sharing of risks between users and providers, based on 'strong levels of network performance':

> Network failures and actions that result in losses to the generator particularly those associated with connection assets should also impact on the network owner. There needs to be a financial penalty available to the generator when the network owner does not meet his obligations as defined in the connection agreement. This is not to say that the network should be exposed to the full loss that the generator incurs but that there should be a code requirement for some form of liquidated damages.[10]

These submissions also wanted the NSPs' delivery of network performance to be used as an indicator in assessing their entitlement to regulated revenue.

Ancillary services

Several submissions also voiced concerns over the obligation to provide ancillary services through negotiated connection agreements and NEMMCO directions, based on technical and system security requirements. They did not think it appropriate for NSPs to provide such services through connection agreements. Instead connection agreements with networks should be restricted to the level of service so that the risks to generators and customers from loss of transmission can be properly managed:

> The currently proposed arrangements are unsatisfactory and will lead to inefficiency, excessive cost to the customer and unnecessary barriers to entry. Networks should not be negotiating aspects of system security and ancillary services via network connection agreements.[11]

They also indicated that several services which the code allocates to the NSPs properly belong with the market operator and system security. Even so, they claim the code is uncertain regarding NEMMCO's discretion to pay for these services.

They prefer ancillary services to be sourced competitively based on a fully informed market where generators providing such services are appropriately recompensed, especially where they are directed by NEMMCO. However, there is also a perceived need for transparency and monitoring of these market transactions to prevent generators exploiting compensation arrangements.

Note that the role of NEMMCO in providing ancillary services has also been examined in the Commission's authorisation determination.

Derogations

The Australian Cogeneration Association (sub., p. 33–34) and the Energy Users Group criticised the derogations from the code's technical standards on several grounds:[12]

- neither the Tasmanian or Queensland derogations are available for detailed comment; and
- established generators (typically coal-fired plant) will be exempt from the technical standards, whereas cogeneration plants and new entrants will not be exempt.

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10 Macquarie Generation, sub, p. 2 ; see similar comments in Hazelwood Power; Ecogen Energy; Snowy Mountains Hydro-electric Authority.

11 Snowy Mountains Hydro-electric Authority, sub., pp. 7--9; also Energy Users Group; Yallourn Energy; Hazelwood Power; Delta Electricity; TransGrid; Ecogen Energy; energyAustralia; Government of South Australia.

12 The submission also criticised several of the network pricing features of these derogations. Also see Energy Users Group, p. 94.

The EUG (sub. pp 4–5) also requested that the applicant demonstrate that the New South Wales derogations (which adopt the New South Wales System Operating Procedures) are 'not anti-competitive and are consistent with the National code and market objectives.'

The technical consultancy (pp. 74–77) suggested that more justification would be appropriate regarding the Victorian and South Australian exemptions for generator and network performance. It also suggested other improvements:

- making all variations to the requirements of the code available to all code participants to ensure consistent and fair application of the requirements; and
- upgrading non-compliant facilities to meet the requirements of the code when the facilities are eventually replaced or upgraded.

4.3.4 The Commission's considerations

Code complexity

The Commission recognises that electricity networks involve sophisticated technology involving a diversity of inter-related providers and users which in turn imposes significant safety, liability and service quality complications. As with connection procedures, different interests need to be balanced including important public interest needs of health and safety. The need to protect life and property is agreed by providers and users as a fundamental priority.

The issue of complexity emerges as an important concern for users. By its nature the code and especially the engineering requirements of system security and technical operations must be complex, requiring a suitable level of competence to interpret and implement its provisions. The sophistication of modern electricity networks means the scope to simplify this complexity is limited.

However, the criticism of complexity also points to difficulties participants have in reading and interpreting the content and intentions of the code. The submissions show that this occurs in several ways, for example:

- provisions are too long, awkwardly phrased and/or legalistic in form;
- topics are treated in an uneven or inconsistent manner; and
- provisions are not adequately cross-referenced to other code provisions or the National Electricity Law where relevant.

Network service providers have an obvious advantage in that they have the skills and information to negotiate on these issues and develop them constantly in a range of situations. In contrast, even though most users wishing to negotiate connection arrangements may have the commercial ability to deal with the issues, acquiring the technical competence will be infrequent and often too difficult or costly. The availability of such skills may develop as the market matures but presently there will continue to be a significant gap between the competence of providers and users.

One way of redressing this inherent disadvantage is to recognise it more explicitly in the implementation and structure of the code. This can be achieved in a number of ways, for example:

- publishing guidelines targeted to different types of customer and different aspects of network operation, technical standards and system security; and
- introducing more explicit recognition of users' comparative disadvantage in the code change, complaints and dispute processes.

Reflecting these concerns, in its draft decision the Commission recommended that:

> **NECA review the complexity of technical standards and produce guidelines on the level of compliance appropriate to different participants.**

As noted above, submissions from users emphasised the need for negotiation principles and guidelines. The ACA states that the code is intimidatory and is potentially a barrier to new entrants, especially for smaller scale generators including cogenerators and renewable technologies. Australian Paper states that a vast amount of the specified detailed requirements are inapplicable to small scale connections to distribution systems.

Technical requirements on generators

Comments from both the consultants and submissions suggest there are a number of concerns regarding the technical requirements applying to generators and more specifically co-generators, embedded generators and alternative generators. These concerns are set out in the consultant's report (Western Power, pp. 49–52, 56–57) and include such issues as:

- leading and lagging ranges for synchronous and asynchronous generators;

- justification of reactive requirements set by NSPs;
- information requirements relevant to non-synchronous generators; and
- data requirements for generators equal to or smaller than 30 MW.

While it is likely that many of these issues were considered in preparing the code, the Commission maintains the view expressed in the draft decision that the applicant should revisit them in light of the consultants' comments. The Commission believes it would be in the interests of facility owners and network users for the applicant to respond to these issues and propose relevant actions, including the consideration of changes by the code Change Panel. Specifically, in the draft decision the Commission stated that:

> **The Commission recommends that the National Electricity Code Administrator respond to concerns raised by the consultants regarding technical standards which will apply to generators, including cogeneration, embedded generation and alternative generation.**

Also related to the issue of technical standards are the derogations which deal with the individual circumstances of existing plant. This issue is discussed below.

Network reliability

A key issue here was not whether standards of performance exist or can be negotiated but how these standards will be implemented in practice, consistent with the aim of achieving 'long term benefits to code participants in terms of cost and reliability of the national grid' (clause 5.1 (d)(1)).

As indicated earlier, the technical schedules of the code oblige NSPs to:

- specify the quantity and quality of network services; and
- ensure a suitable level of service,

they will provide in their connection agreements, consistent with the code's standards or with terms that are 'fair and reasonable.'

However, in light of the concerns raised by generators and other network users as to how these standards will work in practice, the Commission in its draft decision considered that each NSP, as part of their access undertaking, should:

- formalise their approach to these code requirements in the form of a binding code of practice or service charter regarding the provision of network and connection asset reliability; and
- have the code of practice/service charter approved by the ACCC and/or relevant jurisdictional regulator (subject to any relevant conditions required by the regulator).

Specifically, the Commission's draft decision stated that:

The Commission recommends that each NSP develop a service charter on network reliability as part of its access undertaking to demonstrate how it will comply with code requirements on technical standards and operational performance.

Ancillary services

On the question of ancillary services, the Commission is aware of the arguments for and against the central provision of these services, particularly during the transition period. In its draft decision on the NEM market rules, the Commission argued that the provision of ancillary services necessary to maintain a secure power system should be contestable and driven by market incentives. In addition, the Commission argued that, consistent with the development of market arrangements, the code should encourage the development of an ancillary services market and limit NEMMCO's intervention to the provision of system security which the market cannot deliver.

Accordingly the Commission considers that the inclusion of ancillary services in connection agreements should also be phased out to a minimum once market mechanisms are established for the trading of these services, unless individual network users and NSPs agree otherwise as part of their connection agreement.

Consistent with these views, in its draft decision on the access code the Commission stated:

The Commission recommends that the NECA review on ancillary services should include an examination of their provision in connection agreements with a view to phasing them out once there is an ancillary services market.

At the pre-decision conference and in subsequent submissions,[13] there was general support for an early review of the provisions relating to ancillary services with the objective of introducing market-based arrangements for the delivery of such services. The majority of these submissions support the Commission's condition that NEMMCO report on the review findings to NECA within one year of the market commencing. Several submissions cited the capacity of dispatch software to accommodate the trading of ancillary services.

There is general support for the unbundling of ancillary services as separate products outside of the pricing arrangements for network services or pool fees. Submissions from several generators[14] indicate that commercial arrangements for the supply of ancillary services would be a more suitable means of supporting technical requirements for network and system security. They also state that a corollary of an ancillary services market would be revision of the code to remove a perceived bias favouring NEMMCO contracts for ancillary services, to remove ancillary services requirements from connection agreements and to revise existing

[13] EUG; Business Council of Australia; CitiPower; Eastern Energy; Solaris; SMHEA; Macquarie Generation; Yallourn Energy.

[14] Delta Energy; EME; Hazelwood; Loy Yang; Optima Energy; Incumbent Victorian generators.

technical standards for generators.

Some submissions advise caution in the development of an ancillary services market. Hazelwood states that a two year time frame for the review would be more appropriate given that the need for substantial code changes to the technical standards for generators and to ancillary services arrangements. Similarly, Pacific Power proposes that current arrangements for ancillary services remain in place until the review is completed, to ensure the capacity of the dispatch software and the commercial viability of new arrangements. Dr Hugh Outhred, commenting on the NEM 1 Ancillary Services Project, questions whether one year would allow sufficient time to achieve a balanced outcome which accounts for distributed resources and demand side perspectives.

System security

Regarding system security, the Commission understands that the correction of some system security problems requires the operation of network equipment and services for which NSPs are directly responsible. At the same time users are questioning the rationale for NSPs supplying or directing such services on the grounds of unnecessary duplication or potential conflicts of interest.

In light of the apparent uncertainties and misgivings regarding this issue, the code needs to clarify the roles of NSPs, NEMMCO and system security operators working for NEMMCO with particular attention to who will provide which system security requirements most effectively. Provision of ring-fencing guidelines by jurisdictional regulators with respect to networks is discussed in chapter 3 of this report.

Again these issues indicate a number of areas where disputes are likely, thus putting the onus on the various dispute procedures (either derogated or in the code) to resolve problems promptly, fairly and effectively. Apart from a more explicit recognition of user needs, the effectiveness of the dispute process in dealing with these issues and providing workable outcomes needs to be monitored.

Technical standards and derogations

Submissions and the Western Power study identified potential barriers to entry in the derogations exempting incumbent (usually older, large-scale) plant in Victoria and South Australia from a range of technical standards which will continue to apply to new and small scale plant. Uniformity of standards and transparency of information between jurisdictions and NSPs is seen as critical issues in terms of its potential impact on the connection and compliance costs of users and the incidence of barriers to entry across the interconnected market.

At the same time, the Commission recognises the benefits to facility owners, network users and electricity customers of having a staged period of transitional arrangements, including the need to minimise the impact of major price or cost ‘shocks’ created by code requirements, particularly given the capital intensity of generation and network assets.

Inconsistency due to different rulings or NSP practices in different jurisdictions would cause concern for the Commission if there was a significant cost or interference affecting the ability to trade across market boundaries or deal with other providers. While the Commission recognises that derogations may involve discrimination which is justifiable in the light of countervailing public benefits, it would not favour ongoing arrangements which sustain anti-competitive results through a form of artificial protection or favourable treatment.

In its draft decision the Commission called for further justification of the Victorian and South Australian derogations together with a commitment that their facilities will comply with relevant code requirements when they are upgraded. The Commission also proposed that the development of a market for ancillary services should aim to create commercial incentives for facility owners to upgrade their operations so they can competitively provide such services. In addition, in its draft decision the Commission stated that:

> **Derogations exempting Victorian and South Australian facilities be revised so that they comply with the code at their next upgrade and the derogations are limited to a definite period. In addition, the development of an ancillary services market should aim to create incentives to encourage facility upgrades on a commercial basis.**

Discussion at the pre-decision conference focussed on the high level of performance demanded by the technical requirements currently specified in chapter 5 of the code, the net cost of compliance (particularly for generators) and hence the need for continuing derogations. This was contrasted with the satisfactory state of system security at present with the existing derogations (not the code) setting the actual operating standards.

Some parties suggest that chapter 5 could in fact be reduced to a range of common minimum standards, thus enabling existing generators to operate in the market and comply with the standards. Where facilities have extra technical features these could be compensated for through the provision of ancillary service payments, and in this manner the level of reliability of the power system need not be compromised by lower technical standards in the code.

The incumbent Victorian generators focus on the difficulty that generators and NSPs will have in complying with the code's present technical standards, especially if the derogations from these standards end by 2002. They state that no power station meets the code requirements but system security is functioning adequately. Further they contend that the cost of upgrading existing facilities is prohibitively high compared to the cost of meeting the technical requirements when commissioning new facilities. Moreover the derogations were rigorously tested before inclusion. They also state the original code approach of requiring new entrants to meet modern technical standards could now be questioned as not all new generation will be small or cogeneration (eg large gas turbines scheduled in Queensland).

Two solutions were proposed:

- NECA should revise the code to state absolute minimum requirements and establish ground rules for safe grid connection with few or no derogations. The focus would be on removing all barriers to entry based on modern technology standards and differing technology types. Higher requirements should be met through ancillary services contracts or markets. It was noted that there may be some difficulty in agreeing to an acceptable minimum standard; or

- Accept permanent derogations for existing generators and attempt to improve standards over time, in particular reviewing the technical requirements to see what is absolutely necessary for new operators.

Delta states that the code should only specify common performance requirements and that some characteristics only need to be available from a few suppliers to achieve system security measures which should be dealt with as ancillary services. The ancillary services working group concluded that most ancillary services can be sourced competitively (eg frequency and voltage control) or through a regulated price mechanism. The Victorian Government considers that a more efficient alternative to removing the technical derogations is to require incumbent generators to contribute to the additional costs incurred by new entrants in complying with the redefined standards.

The BCA/EWG and ACA raise the concern that new generators (eg cogeneration) will have to face a higher level of standards than incumbents. While seeing the logic of minimum standards they are concerned that the cost of system standards will be borne by new entrants and users. Further, that new entrants may bear the cost of rectifying the system. They also flag the issue of competitive neutrality between public and private participants in industry. Hazelwood agrees that new entrants to the market should not have to bear the costs of rectifying the system.

TransGrid cautions against lowering standards to a lowest common denominator, because a reduction to only match present capacities could jeopardise system security. TransGrid and the BCA/EWG support a thorough review of chapter 5.

The Commission accepts the general view put forward at the pre-decision conference that the need for technical derogations arises because of the construction of chapter 5 of the code. Several participants state that none of the incumbent generators can meet the code's technical requirements, yet the system currently operates at a high level of safety and reliability. The effect of the derogations is to reduce the technical standards to those currently in operation. However, the purpose of chapter 9 is to allow for derogations which are of a transitional nature in order to enable code participants to effect an orderly transition to the provisions of the code. For derogations of a more permanent, or non-transitory nature, code participants are able to apply for a derogation under clause 8.4 of the code.

The Commission is concerned that entry barriers could be created by grand fathering existing facilities but requiring new facilities to meet code requirements. The Commission prefers to have these derogations cease after a short transitional period, thereby allowing the facility owners (ie code participants) to seek a derogation under chapter 8 of the code.

4.3.5 The applicant's response

In response to the Commission's concerns about technical standards, in particular generator standards, NECA has amended the code which requires it to undertake a review of generator technical standards within two years of market commencement. Specifically, clause 5.2.6 has been inserted which states:

> 5.2.6 Within 2 years of *market commencement* NECA must undertake a review in accordance with the *Code consultation procedures* of and report on the technical standards to which *Generators* must adhere pursuant to schedule 5.2 of Chapter 5. The review must consider:
>
> (a) whether these standards are too stringent to be met by persons seeking to develop *generation* facilities;
>
> (b) the relationship between these standards and the provision of *ancillary services*;
>
> (c) the need for consistency in adherence to technical standards by *Generators* throughout the *market*; and
>
> (d) such other matters as *NECA* considers appropriate.

Similarly, the chapter 9 of the code has been amended to ensure that Victoria's and South Australia's derogations for generator technical standards end on 31 December 2002. Specifically, Victoria's derogations have been amended by the insertion of clause 9.7.6(b) which states:

> (b) This clause 9.7.6 ceases to apply on 31 December 2002.

And South Australia's derogations have been revised and clause 9.28(c) states:

> (c) obligations imposed on *Generators* under clause ~~5.2.4~~ 5.2.5(a) and schedule 5.2 of the *Code* are subject to the variation, amendments or other derogations in schedule ~~9E1~~ 9D1, which variations, amendments or other derogations end on 31 December 2002;

In response to the Commission's concerns about the inclusion of ancillary services within connection agreements, the applicant stated that NEMMCO is required to review of ancillary services and the revised provisions on ancillary services are to be incorporated into the code by 1 July 1999. The applicant added that:

> In the light of that review, NECA will consider how to take forward the Commission's concern that, as far as possible, ancillary services and system security conditions in connection agreements are phased out.

The Commission's suggestions concerning the development of service charters by the NSPs are to be addressed in NECA's review of transmission and distribution pricing.

4.3.6 The Commission's findings

The Commission believes that the code changes, which require NECA to undertake a review of generator technical standards within two years of market commencement, go some way to meeting the Commission's concerns about the complexity of, and potential entry barriers created by, generator technical standards. The Commission also believes that as a result of South Australia and Victoria limiting their technical derogations to the end of the year 2002, there is a reduced likelihood that the technical standards will create an entry barrier. However, by imposing these end dates, this does not mean that all facilities must upgrade to the code standards. When the Commission made both its access code draft decision and authorisation determination it noted that an alternative process for derogations exists and recommended that if the technical derogations currently set out in chapter 9 of the code need to be extended then the processes outlined in clause 8.4 of the code should be followed. Nevertheless, to minimise entry barriers caused by technical derogations, the Commission maintains its view that participants should be obliged to upgrade their facilities to bring them more into line with code requirements but only where such upgrades are commercially justifiable. Moreover, new entrants should not be required to compensate for existing equipment which does not meet code requirements.

In general, technical standards serve a particular function in ensuring that the needs of the electricity market are met and, ideally, in a least cost manner. While the Commission is satisfied with the applicant's commitment to undertaking a timely review of technical standards, this is no guarantee that the issues will be resolved. Indeed, the Commission would be disappointed if the outcome of the review were technical requirements which either reflected some "lowest common denominator" and thereby degraded service quality or which could be used to create anti-competitive entry barriers for either new technologies or new entrants. Given this concern, the Commission believes that the following points should also be considered for inclusion in the network technical requirements principles:

- that existing plant is required to upgrade to meet the code requirements where economically feasible; and
- if it is not economically feasible for existing plant to upgrade then new entrants are not required to compensate for the derogations.

In addition to reviewing and amending the technical requirements, the extent of any entry barriers will be minimised where an effective market for the supply of ancillary services creates a financial incentive for generators and others to meet the various code requirements. In this context, the Commission welcomes the applicant's code changes which bring forward the NEMMCO review of ancillary services. The Commission accepts NECA's commitments that it will subsequently consider the scope for removing ancillary services and system security conditions from connection agreements in line with the development of an ancillary services trading market.

The Commission accepts the applicants' plan to consider a service charter for network service providers in the context of the NECA pricing review.

4.4 Inspection, testing and commissioning requirements

The access code includes inspection and testing provisions to ensure that connected equipment complies with the specified performance criteria. These arrangements create rights to enter establishments to conduct commissioning tests on new or replaced equipment and conduct tests on existing systems and equipment.

4.4.1 Issue for the Commission

In general, electricity cannot be cost effectively stored in large quantities so it must be produced and consumed instantaneously. Moreover, electricity is hazardous. Consequently, electricity transmission and distribution systems need to be balanced in terms of supply, demand, voltage and frequencies. Achieving this balance and maintaining technical performance standards requires ongoing checking and testing of equipment and processes. The access code aims to achieve this through compliance by NSPs and users with defined rights, obligations and procedures for inspecting, testing and commissioning the network and connected equipment.

While it may be in the public interest to regularly check the network to ensure optimal performance, the Commission also needs to be confident that the code mechanisms for achieving this objective are in the interests of NSPs and network users in that they do not impose impracticable standards or involve the risk of undue or arbitrary interventions. The Commission's concerns here are the cost to participants, and impact on access, of compliance with a range of technical and operational benchmarks, weighed against the desirability of uniform conformity with, and enforcement of, an objective standard.

In particular, the issues for the Commission are the extent to which the inspection, testing and commissioning provisions:

- are reasonable and apply equally to NSPs, users, incumbents and new entrants;
- are vulnerable to misuse which might unreasonably limit or hinder access and, if so, whether they contain adequate safeguards to prevent any such misuse;
- achieve a reasonable balancing of collective and individual interests in respect of NSPs and network users as well as the public interest in having a safe, effective and responsive electricity system; and
- do not create a conflict of interests in assigning rights and obligations to different parties in respect of the monitoring and maintenance of network performance.

Also, given the natural monopoly attributes of network service provision, the Commission needs to be assured that NSPs will not abuse of their market position in meeting their code obligations and supervising users' conduct.

4.4.2 What the applicant says

The main purposes of the inspection, testing and commissioning procedures are to:

- assess compliance with the code;
- assess compliance with industry standards on performance either for individual equipment or for the grid;
- conduct tests related to disconnected and reconnected equipment; and
- provide adequate notice of tests which may adversely affect other users or networks.

In detailing the various procedures, the code establishes a range of rights and obligations (see Box 4.3 for details). Tests by NEMMCO must be notified to all affected participants and NSPs. Testing of inter-regional transmission networks is co-ordinated by the Inter-regional Planning Committee and approved by NEMMCO and all associated transmission NSPs. These tests are required: when new transmission or generation assets affecting power transfer are commissioned; when existing lines are augmented; or when system changes or performance require testing. The code requires adequate notice, development and co-ordination of the testing program and approval from all affected NSPs and participants before the test can take place.

All new and replaced equipment must be tested and certified to ensure compliance with the code, the relevant Australian Standards and the relevant connection agreement. Testing must:

- ensure minimum adverse effect on system security and quality of supply and minimum threat of damage to other equipment;
- be preceded by the submission of relevant design information to the NSP and consultation with other participants; and
- be agreed with the relevant NSP and NEMMCO on the commissioning program.

NEMMCO or the NSP may witness tests and the test results are sent to the NSP to demonstrate compliance or otherwise. The participant and NSP must negotiate a process for achieving compliance of any equipment failing the test. NEMMCO may withhold approval from any commissioning and connection where equipment does not meet the specified standards.

There is a general obligation on NSPs and participants to operate and maintain networks, plant and equipment in compliance with the code, industry standards and system security. This includes enabling and maintaining connections, planning for network developments and meeting system performance and quality requirements. Connection and ancillary service agreements may also specify the level of performance required from connected parties and their equipment.

Box 4.3: Rights and obligations for testing and inspection

The access code defines the rights and obligations of NEMMCO, participants and NSPs regarding inspection, testing and Commissioning of connected equipment and systems.

NEMMCO has a right to:

- inspect facilities and equipment;
- assess compliance with the code;
- gauge possible risks to system security; or
- 'conduct periodic familiarisation or training' on operational requirements.

A party to a connection agreement has the right to inspect the facility or test the equipment of another party to the agreement in order to assess compliance with the code or the connection agreement. The inspecting party must:

- give at least 2 business days notice;
- pay for the costs of inspection or testing;
- cause no damage, involve minimum interference and observe relevant occupational health and safety and industrial relations requirements;
- report on the results of the inspection or test; and
- not request an inspection or test within 6 months of a previous test except to check the adequacy of corrective action.

Generators must:

- institute a monitoring program to ensure compliance with the relevant technical requirements of the code;
- undertake any remedial work or tests required for compliance;
- comply with instructions from NEMMCO or the relevant NSP to test its units to prove compliance;

- be reimbursed for tests so requested if the unit complies with the standards;
- keep monitoring and test records for 7 years; and
- co-operate in yearly modelling tests which require changes to normal operation.

All participants must:

- co-operate with the NSP's routine testing of protection systems;
- notify their NSP when testing their own equipment, with the provisos that the test must be:
  - ⇒ reviewed to determine adverse effects to the network; and
  - ⇒ modified or delayed if NEMMCO decides the test will threaten the safety or integrity of the system.

The provisions of the code including those relating to planning, designing and operating criteria, apply to all code participants and NSPs. However, the code provides for variation of the requirements where it is economic to do so. To protect other code participants, it is the responsibility of the code participant seeking the variation to demonstrate that the variation will not adversely affect other code participants.

NECA's application for the access code did not indicate how the proposed inspection, testing and commissioning requirements were in the interests of either NSPs, network users or the wider community.

4.4.3 What the participants say

In general, submissions ignored the access code's proposed inspection, testing and commissioning requirements. However, when comments were made, participants were critical of two aspects of these requirements.

First, the SMHEA (sub., pp. 8–9) considered that the quality of service obligations are unbalanced. On the one hand, customers and generators must prove their capability under stringent requirements. Conversely, NSPs have no requirements or tests for performance to ensure an appropriate level of customer service.

Second, Mr Chek Ling (sub., p. 2) argued that the code inappropriately stipulates that the NSP should conduct system testing. He argued that the system operator would be the more appropriate organisation to conduct system testing.

The consultants recognised that the right to enter another's facilities to check a possible breach of the code or connection agreement is an effective way to encourage all participants to take an active interest in the power system and to sort problems out between themselves rather than the alternative of NEMMCO or the NSP intervening each time.

However, they warned this could be open to abuse, notwithstanding that there is a connection agreement, particularly if the parties are competitors (eg in the case of interconnected NSPs) and given that only two days notice is required. They suggest a longer period as more appropriate unless the problem requires urgent attention. Overall their conclusion is that:

> It would appear to be more appropriate to have either the NSP, NEMMCO or NECA investigate alleged breaches of the code or a connection agreement.

The consultants considered the commissioning requirements are reasonable and would generally be in accordance with accepted industry practice. The only concern relates to the fact that the IRPC has the final say on control and protection settings for equipment:

> Given that the IRPC is not independent, it is possible for a conflict of interest to occur. Perhaps it would be better to have the settings reviewed by an independent expert.

4.4.4 The Commission's considerations

The general issue of monitoring how different participants comply with the technical standards applies across the access arrangements. The code approach is mostly reactive (ie it deals with problems as they occur, through breach and dispute processes) although in some areas regular reviews and reports are planned (eg network pricing; dispute findings).

The Commission recognises that network tests are needed regularly to preserve and enhance the common benefits of system integrity, to maintain the commercial value of the network asset and to protect the interests of different users and providers.

In this respect, the code's primary focus should be on enhancing and balancing various interests and achieving this through a range of incentives and disincentives. The applicant's submission shows that the code aims to:

- identify responsibilities for network security;
- check and remedy potential or actual problems;
- consider the interests of all users and providers without bias; and
- use interventions only with workable checks and balances.

The entry, inspection and testing rights create incentives for both providers and users to comply with their technical responsibilities and there are safeguards against vexatious behaviour. Even so, this does not avoid the immediate cost of interference nor the opportunity for disputes about inspection costs and it does not account for the effect that spot inspections may have on third parties connected to the same network.

In its draft decision, the Commission indicated its concern that the right to inspect another's premises and equipment may be misused for anti-competitive purposes rather than code objectives. Such rights, particularly between competitors (eg two interconnected NSPs), rarely exist in other markets. They carry with them some risk of conflicts of interest, market interference and even the potential for industrial espionage. Moreover, the code does not allow a participant to object or appeal once notified of an impending inspection.

The Commission suggested that one way of minimising these potential conflicts of interest is to move the inspection function from the hands of participants to an independent body such as NEMMCO or NECA. The benefit of this would be to establish a system of inspection seen to be impartial and whose authority to make binding decisions is accepted by participants. Also, the actions and decisions of an inspectorate might be more open to public scrutiny through accountability and monitoring arrangements.

However, the Commission also recognised that it would be costly to establish and maintain a separate inspectorate. Moreover, an inspectorate's activities may be limited by both insufficient resources and information problems. It could also deprive participants of initiative and responsibility in managing their own affairs while creating an extra layer of bureaucracy within the industry.

In concluding, the Commission's draft decision observed that it is apparent that the system for spot inspections and the alternative of a separate inspectorate each has its costs and benefits, and a decision in favour of one or the other will involve a trade-off between these factors.

However, the Commission appreciates that the rights in clause 5.7 are an improvement on existing inspection rights and have been designed with several safeguards in place to meet the concerns of bias and potential for abuse. Moreover, in its draft decision, the Commission argued that the effectiveness (or otherwise) of these safeguards should be tested, after an appropriate period of time, by NEMMCO based on the experience of participants in the market to see whether they are achieving their stated objectives without detriment to access or competition.

Alternatively, existing code provisions need to be strictly limited and audited; after a suitable period of use, a review could be conducted to see whether inspections should be autonomous.

Reflecting these various concerns, in its draft decision the Commission recommended the following changes to the rights to entry, inspection and testing provisions of the code.

> **The language of clauses 5.7.1 and 5.7.2 should be reviewed to prevent the rights from being abused for anti-competitive purposes.**
>
> **Reports of inspections and tests should be available to the participant being inspected, the participant requesting the inspection, other affected parties and NEMMCO.**
>
> **NEMMCO should carry out an annual review of the use of these rights based on reports received, to determine the effectiveness of the provisions, their effect on competition and whether the inspection function should be independent of participants.**

In response to the Commission's draft decision, TransGrid and the New South Wales distribution businesses submit, with regard to inspection rights, that the intent of the code was to provide reciprocal rights in a connection agreement as an improvement on the unilateral network service provider rights which currently exist. They also point out that such rights are likely to be exercised in respect of suspected code breaches or in response to customers complaints about the quality of supply. In either case the NSP would have to be involved in the inspection to investigate the problem.

TransGrid also recommends that the annual review of inspection rights be carried by NECA rather than NEMMCO, as it has more to do with code effectiveness than market operation.

4.4.5 The applicant's response

In responding to the Commission's concerns over the potential for participants to abuse their inspection rights, the applicant has committed itself to undertaking a review and has already introduced some code changes. In particular, the applicant stated that "in consultation with

NEMMCO, NECA will review facility inspection provisions in cls 5.7.1 and 5.7.2 with an eye in particular to the Commission's concerns".

In responding to the Commission's concerns over the transparency of the facility inspection arrangements, the applicant inserted a new clause 5.7.1(l):

> (l) A *Code Participant* (in the case of an inspection carried out under clause 5.7.1(a)) or *NEMMCO* (in the case of an inspection carried out under clause 5.7.1(h)) must provide the results of that inspection to the *Code Participant* whose *facilities* have been inspected, any other *Code Participant* which is likely to be materially affected by the results of the test or inspection and *NEMMCO* (in the case of an inspection carried out under clause 5.7.1(a)).

and amended clause 5.7.2(i):

> (i) A *Code Participant* who conducts a test must submit a report to the *Code Participant* who requested the relevant test, *NEMMCO* and to any other *Code Participant* which is likely to be materially affected by the results of the test, within a reasonable period after the completion of the test and the report is to outline relevant details of the tests conducted, including but not limited to the results of those tests.

4.4.6 The Commission's findings

The Commission believes that the code acts in the interests of facility owners, network users and the broader Australian community by providing for testing and inspection of all connected equipment and facilities. Testing and inspection allows for the prompt identification of any problems which may impinge on system integrity, network assets and the health and safety of the community.

While the code includes some rights to prevent the abuse of the testing and inspection powers, the Commission is concerned that these provisions may prove insufficient. Rather than establishing a separate inspectorate which would have its own costs and problems, the Commission believes the existing measures should be tried and tested first and found wanting before imposing an extra level of bureaucracy on the activities of facility owners and network users.

The Commission accepts the applicant's commitment to review the code arrangements with a view to limiting the potential abuse of inspection and testing rights by code participants. The Commission also accepts the applicant's code changes which improves the transparency of the code's inspection and testing procedures.

Nevertheless, participants should note that the Commission reserves its right to pursue abuse of market power and other anti-competitive issues under the TPA as necessary, irrespective of code processes.

4.5 Disconnection and reconnection

The access code provides for either voluntary or involuntary disconnection from the network. Procedures are set out in the code which must be followed in both events. The code also sets out the conditions for reconnection.

4.5.1 Issue for the Commission

Although based on negotiation and mutual agreement, voluntary disconnection will still impose costs on the participant due to disconnection and decommissioning of equipment necessary to ensure system security. However, the NSP seems to be the final arbiter on what is necessary in these circumstances in which case the Commission would be concerned if these costs were to create barriers to exit, thus reducing mobility and investment in the electricity market.

On the other hand, involuntary disconnection entails a more drastic intervention into access arrangements and will usually arise from events such as system failure (including emergencies or poor management of the network), code breach or default on payments. Disconnection results in the participant being cut off from physical supply and consequently unable to trade or use electricity. Reconnection also involves additional costs for the NSP and participant.

Given the costs and handicap caused by involuntary disconnection the Commission needs to be sure that:

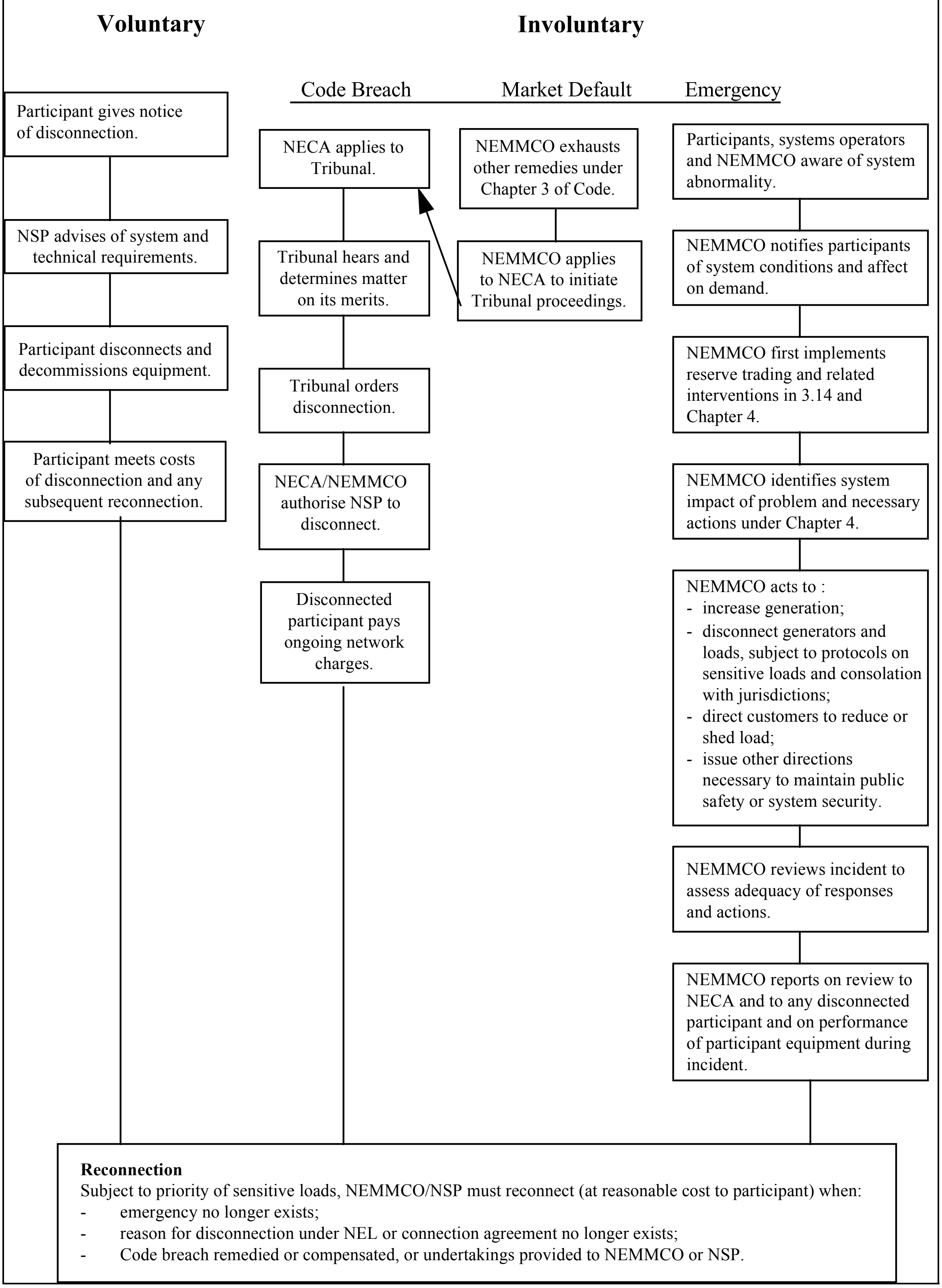
- the interests of both network providers and participants, both individually and collectively, and the public interest are properly identified and heeded in the decision-making that leads to disconnection;
- the principles and procedures for involuntary disconnection are based on fair and reasonable criteria, are not anti-competitive, arbitrary or discriminatory and seek to minimise the risks of negligence, unfair treatment or error;
- the need for disconnection in any individual case is reasonable as a matter of last resort or in the face of an emergency; and
- involuntary disconnections are accountable to the code objectives and thus open to review, recognising that in some situations (eg system emergencies) immediate review would be impracticable and counter-productive.

4.5.2 What the applicant says

The applicant (sub., pp. 45–46) only refers to disconnection when describing what actions and decisions NEMMCO will follow in dealing with emergencies involving disconnection (see below). The rest of the following information comes from the code and the procedures are set out in a flow-chart in Figure 4.2 below.

Under the code disconnection from the network can be voluntary or involuntary. Procedures are set out in the code which must be followed in both cases

Figure 4.2: Disconnection



In terms of voluntary disconnection, unless specified otherwise in a connection agreement, a participant:

- must give the NSP notice of its intention to permanently disconnect a facility from a connection point; and
- is entitled to require permanent disconnection of its equipment from a network.

The code participant must pay the costs of voluntary disconnection and decommissioning, and follow the appropriate procedures so that disconnection does not threaten system security.

In terms of involuntary disconnection, NEMMCO or a NSP can disconnect a participant's facilities from a network pursuant to a National Electricity Tribunal order; during an emergency; under the National Electricity Law; or in accordance with the provisions of the participant's connection agreement.

National Electricity Tribunal Order

The National Electricity Tribunal is the body responsible for:

- adjudicating applications by NECA that a participant has breached a provision of the code, including applications for disconnection, and
- reviewing certain decisions of NECA and NEMMCO which are identified as 'reviewable decisions' in the code.[15]

Also, where a market participant incurs a default and other default procedures (ie issue of a default notice; suspension from the market) have been exhausted, NEMMCO must request NECA to seek a disconnection order from the Tribunal.

If the Tribunal finds that the participant is in breach of the code, one of its options is to suspend the registration or other specified rights of the participant. It is not clear whether the Tribunal will rely on this provision in the National Electricity Law to order the disconnection of a participant as envisaged by the code.[16]

To give effect to a Tribunal order, NECA may direct a NSP to disconnect a participant from any transmission or distribution system. In such circumstances, neither NEMMCO nor the NSP will be liable for any loss incurred by the participant.[17] Moreover, the participant must

[15] Reviewable decisions are discussed in chapter 6.4 of this report.

[16] NEL s44(2). Other options allow the Tribunal to order the Code Participant to pay a civil penalty, cease the conduct, remedy the breach and/or implement a specified compliance program.

[17] Code clause 5.9.4(a). Neither NEMMCO nor the NSP will be obliged for the duration of the disconnection to fulfil any agreement to convey electricity to or from the Code Participant's facility.

continue to pay any transmission or distribution charges as if the disconnection has not occurred.

If NECA considers that a code participant may be the subject of a disconnection order from the Tribunal, NECA must notify NEMMCO and any affected jurisdictions, and use reasonable endeavours to ensure continued supply of electricity. [18]

Emergencies

Disconnection Powers

The code and National Electricity Law contain several provisions which allow NEMMCO to disconnect a participant's facilities during an emergency. According to the applicant (sub., p. 44), NEMMCO acts as a central co-ordinator taking a national rather than regional responsibility for the power system:

> Both the National Electricity Law and the code provide NEMMCO with significant powers of direction to maintain public safety and the security of the power system. When the power system is affected by a contingency event (eg. failure of a major generating unit or a transmission line) NEMMCO will work with the System Operators to identify the impact of the event on the capability of the power system and identify and implement actions required in each affected region to restore the power system to a satisfactory operating states.

Under the National Electricity Law, NEMMCO may request a participant to take any action required for public safety or the security of the electrical system, including shedding or variation of loads and generation and disconnection of equipment. If the participant fails to act within a reasonable period, NEMMCO may authorise another person to perform the requested action. The code requires NEMMCO to:

- exercise these powers consistently with the sensitive loads of participating jurisdictions; and
- comply with the market intervention procedures set out in clause 3.14.

The code entitles NEMMCO to disconnect one or more points of load connection when there is a shortfall in electricity.[19] NEMMCO must liaise with the relevant participating

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[18] Code clause 8.5.4(f). However, clause 8.5.4(f) does not require or entitle NECA to do anything likely to result in a net auditable change in the financial position of any other Code Participant: clause 8.5.4(g).

[19] Code clause 4.8.9(a)(2). During a supply shortfall, NEMMCO may also increase generating capability and direct load reduction. NEMMCO must shed load according priorities associated with: agreed levels of security; equity between interconnected regions; sensitive loads (eg hospitals, public transport etc.); and emergency services powers.

jurisdictions to assist in the management of a declared emergency supply situation.[20]

Disconnection Procedure in an Emergency:

Where NEMMCO disconnects a participant during an emergency, clause 5.9.5 of the code allows the disconnection to be conducted gradually or immediately depending on the urgency of the situation. In both cases, NEMMCO is required to undertake a review under clause 4.8.16 and provide a report to the participant and NECA.

Participants must follow any direction issued by NEMMCO relevant to maintaining and restoring power system security. A failure to observe such a direction will be deemed a breach of the code. Any participant who is aware of such a failure must refer the allegation to NECA.

Where NEMMCO has authority under the code to disconnect a generating unit, then NEMMCO may do so as described in clause 5.9. The generator must provide all reasonable assistance to NEMMCO for the purpose of such disconnection.

Reconnection

NEMMCO or the NSP must reconnect a participant's facilities to the network at a reasonable cost to the participant as soon as practicable if:

- NEMMCO is reasonably satisfied an emergency no longer exists requiring disconnection of the participant's facility;
- NEMMCO is reasonably satisfied that there is no longer a reason for disconnection under the National Electricity Law or the connection agreement; or
- the breach leading to disconnection is remedied or other appropriate steps taken.

Other than to ensure the maintenance of power system security or public safety, NEMMCO must also not prevent the reconnection of a sensitive load without the approval of the participating jurisdiction's system operator.

4.5.3 What the participants say

Submissions to the Commission did not address the issue of disconnection.

The technical consultancy considered that the disconnection processes and defined circumstances would appear to be reasonable to protect the interests of NSPs and code participants. They suggested that it would assist participants if, consistent with the National Electricity Law, the code explained the circumstances under which an NSP or NEMMCO can disconnect a participant. They note however, that 'a disadvantage of this approach is the need to ensure that the code is updated if there has been a change in the law.'

[20] See Code clauses 4.8.10(a), 4.3.2(g) & 4.8.9.

While they considered also that the obligations on NSPs to reconnect appear sufficient to protect participants' interests, they raised a concern relating to:

> the provision that the reconnection of a code participant's facilities must be at a reasonable cost to the code participant. The code participant should only have to pay for reconnection if it was in some way responsible for the disconnection in the first place.

4.5.4 The Commission's considerations

The Commission has several concerns with the disconnection procedures.

Complexity of procedures

The design of the procedures for involuntary disconnection makes them hard to follow, something also noted by the consultants. Although the procedures rely on the interaction of provisions in chapters 3, 4, 5 and 8 as well as the National Electricity Law, the lack of cross referencing or summarised information means the code and Law need to be studied carefully before it is clear how and in what circumstances the disconnection provisions will operate in practice.

In addition the above review identifies a number of inconsistencies between the code and the National Electricity Law which could thwart the original intentions and compromise the interests of both users and providers. For example, although the code and application clearly envisage the Tribunal ordering disconnection, there is no explicit Tribunal power to do this. NECA has advised its belief that legislative provisions will not be required to provide the Tribunal with valid powers of disconnection.

Because of this lack of clarity, participants may be at a disadvantage in understanding and using their rights and obligations when faced with the prospect of disconnection. At the same time code bodies or network service providers may be tempted to abuse their information advantage in order to expedite matters or secure a particular result. In both circumstances the principles of natural justice and due process may suffer.

Disconnection is an extreme measure but in some circumstances it will be warranted. The code needs to operate clearly and effectively in defining those circumstances and the procedures to be followed. At the same time the code also needs to identify those cases where disconnection is not an option and what alternatives there are to dealing with the code breach or problem in question. An improved explanation of the use of disconnection as a code remedy is needed to clarify the present uncertainty and complexity.

Reflecting this range of concerns, in its draft decision the Commission stated that:

> **The code must be amended to include a clear statement of intent that involuntary disconnection will be used as a last resort.**
>
> **The code must be amended to specify more clearly the process, rights and obligations of participants and network service providers regarding**

disconnection and rectify the inconsistencies between the various code provisions and between the code and the National Electricity Law.

The code must be amended to specify which code breaches and market defaults will lead to disconnection, consistent with the penalties in the regulations.

TransGrid supported the statement of intent but pointed out that disconnection for emergency conditions is a NEMMCO responsibility rather than a network connection issue and that disconnection can occur without warning (eg due cascading failures). It also supported a clarification of the disconnection procedures but noted this is a complex issue involving jurisdictional legislation covering distribution networks.

Continued payment for services

In its draft decision the Commission questioned why participants disconnected as a result of a Tribunal order should continue paying for services they do not receive 'as if disconnection had not occurred' (see clause 5.9.4 (c)). Disconnection (and subsequent reconnection) themselves impose financial loss and inconvenience on the affected participant. So it is not clear why an additional penalty or disincentive should always apply nor why it applies only to disconnections ordered by the Tribunal.

The Commission indicated that it was aware that some connection agreements may involve connection and network charges being spread over time, such that the participant is liable in the future for benefits received now. This can occur where the NSP has invested new capital for the purpose of connecting the participant and will not recoup these costs if the participant is disconnected and does not meet future liabilities. Similarly, the NSP has a right to recover outstanding debts up to the moment of disconnection. If these are the cases where clause 5.9.4 (c) applies, it would be better if it were rewritten to oblige disconnected participants to meet those present and future charges for which they are liable under the connection agreement and/or energy market arrangements. To ensure that the code has sufficient accountability and flexibility in regard to such payments, actions taken to enforce this obligation should be reviewable decisions.

Reflecting this concern, the Commission's draft access decision stated that:

The code must be amended so disconnected participants' payment for services ('as if disconnection had not occurred') is limited to paying debts and other liabilities incurred under the connection agreement

TransGrid did not support amendment of the 'continued payment for services' provision until the NECA review is finalised. It stated the intent is to remove the risk of a participant avoiding payment for services provided during the disconnection period (covered by a fixed charge) which cause a financial loss to the network service provider. Also on this issue, CitiPower commented that it is a fundamental right to cease supply of a product or service if the consumer does not meet obligations and that the 'connection agreement' in this context should also cover energy consumed and related services.

Payment for reconnection

The Commission also questions whether disconnected participants should pay for reconnection (see clause 5.9.6) when they are not at fault, even if it is 'at a reasonable cost.' Where the participant's actions or omissions have contributed to or caused the disconnection, the relevant NSP should be paid for reconnection. However, where the participant has complied with the code, making him or her pay for reconnection most likely transfers someone else's liability to that participant without justification. Elsewhere the code indemnifies the actions of NEMMCO or an NSP that are made in good faith. Clause 5.9.6 seems to go beyond this in making the participant pay whatever the circumstances.

It would be more acceptable to restrict this condition to those occasions when the participant is responsible for the disconnection. As with the continued payment of network charges, to ensure accountability and flexibility the obligation on individual participants to pay for reconnection should be reviewable by the Tribunal.

Reflecting these concerns, the Commission's draft access decision stated that:

> **The code must be amended so participants pay for reconnection only if they were responsible for the disconnection, through failure to follow the code or connection agreement.**

In response to this draft recommendation, CitiPower stated that if a previous customer has requested disconnection, it does not seem unreasonable that the incoming customer pay for reconnection if this is required.

4.5.5 The applicant's response

The applicant stated that "NECA will review the disconnection arrangements in cl 5.9 to address the concerns raised by the Commission".

4.5.6 The Commission's findings

The Commission considers that the review of disconnection provisions proposed by the applicant will be a useful means to identify, clarify and, where necessary, amend the operation and interaction of the National Electricity Law, the code and jurisdictional laws in relation to disconnection issues. The Commission considers that the review must deal effectively with the specific issues identified in this decision.

In response to TransGrid's point that fixed charges should continue to apply during a disconnection period, the Commission considers that they should be levied only in cases where the customer is at fault. It also accepts CitiPower's point that energy and related liabilities may also be involved. The Commission's intent is that such liabilities (for either network services or energy) be made explicit in the code and/or connection agreement rather than rely on a general obligation to pay for services 'as if disconnection had not occurred.'

In addition, the Commission accepts CitiPower's point concerning reconnection of a site where there is a change of customer. In such circumstances it is reasonable that the new customer pays to reconnect the site. Nevertheless, the Commission's concerns focus on cases of involuntary disconnection and reconnection of the same customer at the same site.

5. Network augmentation, interconnection and planning

A major challenge for any access regime is its ability to cope with dynamic changes in the market such as the investment response to a growing demand to use network facilities. Such additions to the grid are known as network augmentation and can range from minor investments in the existing network to something as major as a new inter–regional connection.

Consequently, the access code's augmentation procedures will have a particular impact on the extent and quality of access as well as on future competition in upstream and downstream markets. In addition to meeting growing electricity demand, the Industry Commission (1995) identified certain network augmentations (ie new interconnectors) as a source of competition with generators. Therefore, to the extent that interconnections are congested (or constrained), the scope for competition in the sale of energy is reduced.

The Commission's approach to assessing the access code's augmentation procedures is consistent with our approach to the access code's connection procedures for new load and generation (see chapter 4). In general, augmentation procedures should be streamlined and transparent to avoid creating unnecessary entry barriers but should be sound to maintain the integrity of the transmission and distribution systems. Wherever possible augmentation should be contestable or subject to 'market testing'.

This chapter assesses the merits of the access code's handling of this through its network augmentation and interconnection procedures. In performing this assessment, and on the basis of the information presented, the Commission has aimed to identify procedures which may significantly impact on the interests of NSPs, network users and the Australian community more generally. The Commission has also attempted to identify deficiencies which limit the benefits which will flow from the access code. In performing this assessment, the Commission has adopted a somewhat cautious approach given the importance of reliable and safe electricity supplies and the evolving nature of the NEM and its associated access regime.

This chapter commences with a brief overview of the proposed access code's procedures (section 5.1). The chapter focuses on the access code's four network augmentation processes, namely: augmentation resulting from a new connection or by modifying an existing connection (section 5.2), augmentation identified by network planning within a region (section 5.3), augmentation identified by the Inter–regional Planning Committee (section 5.4) and augmentation identified by the review process for new interconnectors (section 5.5). The chapter then goes on to discuss the more general augmentation and system planning issues associated with information gathering for planning (section 5.6).

5.1 Overview of network augmentation and network planning

The applicant (sub. p. 223) characterises the access code's network planning and augmentation provisions as:

> ... light handed regulation which relies upon public consultation, mandatory consideration of supply and demand side options to alleviate network constraints, competition between network service providers and/or owners wherever this is feasible, and a primary evaluation criterion of net customer benefit.

In general, NSPs are obliged to plan, design, maintain and operate their networks according to a set of network standards. However, the access code also offers the NSPs and users certain protections regarding new investments. The access code does this by including a cost/benefit test and consultation procedures within the process for assessing investment in network assets.

Given these general procedures, the applicant indicated that the access code provides a number of mechanisms whereby the network can be augmented or new interconnections established, namely:

- augmenting a network can take place, or may be necessitated, either:
  - by the access seeker building a significant piece of new network and connecting it to an existing network; or
  - by the access seeker placing additional loads on the existing network thereby creating the need for supporting network investment;
- augmenting a network may be identified as a result of the NSP's annual review of such matters;
- augmenting a transmission network may also be identified as a result of the Inter-regional Planning Committee's annual review of such matters; and
- a party can augment a network by building an inter-regional interconnector.

The applicant (sub. p. 136) indicated that these processes have common provisions which protect the interests of service providers, users and the public. They also provide a viable third party access regime with public and transparent approval processes. The principles and obligations of NSPs, customers and generators with respect to network augmentation and interconnection are the same as those that exist for any network connection (for further details see Box 4.1).

In assessing the access code's network augmentation and interconnection procedures, the Commission has kept in mind that electricity networks are not a simple array of wires. Network performance can be affected by connections within a NSP's network or by connections within a separate but interconnected network. These impacts may adversely affect a network's performance or they may simply cause a change within a network and/or in an interconnected network. Consequently, to ensure the safe and reliable transportation of electricity, the NSP must carefully balance and monitor its network.

These unintended side-effects are sometimes referred to as externalities or spillovers and the impact an individual has on the network is often difficult to internalise. Moreover, in practice it is not always easy, nor possible, to identify the source of any change in the network's characteristics. It is therefore important that the access code deal with the externality problem that will present itself when a new connection or modification is made to the network.

While particular circumstances and details differ, the public interest issues for the Commission's assessment of the access code's network augmentation procedures, are similar to those examined in the context of network connection, that is;

- to what extent do the augmentation procedures protect NSPs and other network users from potential spillover effects; and
- to what extent do the augmentation procedures create an entry barrier thereby adversely impacting on the contestability of network augmentation.

In the context of the Commission's statutory guidelines, the access code's four separate augmentation and interconnection procedures also raise a number of more specific procedural issues. These general and more specific issues are assessed in the remainder of this chapter.

5.2 A new or modified connection

5.2.1 Issue for the Commission

In general, a connection from either a generator, customer or even from another NSP (including an interconnector) is likely to place additional loads on the network which may necessitate augmenting the network either at the connection point or elsewhere in the system. It is clearly important that NSPs undertake the necessary augmentations to support new connections so access seekers are not routinely hindered from connecting to the network —

eg due to any power transfer constraints on a network. However, it is equally important that NSPs and other network users are quarantined from the costs of having to supply uneconomic augmentations.

Consequently, the broad issue for the Commission is whether the access code establishes an adequate balance between these competing needs. How effectively this balance can be achieved will depend, in part, on whether the network augmentation is fully contestable at each of the planning, construction and operation stages. For example, if augmentation is fully contestable, the applicant could not be hindered from access as they could undertake the necessary augmentation at their own expense (ie participants can use bypass provisions to avoid the local NSP). Moreover, in such circumstances, the NSP or other users would not be left with a risk of financial loss associated with stranded assets.

However, the ability of participants to bypass the network via augmentation will depend on the specific circumstances associated with an individual connection application. For example, it is difficult to envisage how a network augmentation could be made contestable if the new investment is not required at the connection point but elsewhere in a meshed network. Not only would such a bypass be administratively and technically complex, but the incumbent would have an advantage associated with the economies of network density. Conversely, a network augmentation at the connection point is more likely to be contestable.

With these broad considerations in mind, the Commission's assessment of the augmentation procedures associated with a new or modified connection, will be looking to see if the code procedures would ensure that:

- a network augmentation is fully contestable at each of the planning, construction and operation stages; and
- if not, whether the more administrative assessment procedures are transparent and accountable.

5.2.2 What the applicant says

The code obliges NSPs, amongst other things, to make their networks available for connection, and to operate their networks in accordance with system performance, quality of supply and customer service standards. It also allows access seekers to negotiate with NSPs on the terms and conditions relating to any aspect of the service which can be varied without adversely affecting the levels and quality of supply to other network users. The NSP must inform the access seeker if any of their services are contestable in that jurisdiction. Moreover, the access seeker can seek to connect to more than one NSP in respect of any contestable facilities.

These general provisions of the access code establish the mechanism whereby network augmentation and interconnection are contestable. The administrative processes to augment the network are the same as those that apply to any other network connection (for more details see section 4.2), for instance:

- the access seeker must make a connection inquiry detailing the type, magnitude and timing of the connection;
- in response, the NSP must liaise with any other affected NSP and advise the access seeker of any additional information needs (eg technical characteristics);
- the access seeker can then lodge a formal application;
- in preparing a connection offer, the NSP must consult with NEMMCO and any other affected NSP; and
- subject to the negotiation of access terms and conditions, the NSP can make an offer to connect.

The applicant (sub. pp 218–220) argues that the access code protects the interests of access seekers by:

- requiring the local NSP to process the enquiry;
- clearly establishing the procedures to be followed by a party seeking to establish or modify a network connection; and
- only allowing dedicated connection assets to be augmented at the request of the connected participant. Additional services would be covered under a long term contractual relationship (eg a ‘take or pay’ contract) which falls outside the access code’s cost allocation provisions.

The applicant argues (sub. p. 217) that the access code protects the legitimate business interests and investments of NSPs by limiting their obligation to augment a network to circumstances where the augmentation is required to effect or facilitate the connection of a party which is the subject of a connection agreement.

5.2.3 What the participants say

A substantial number of participants, largely potential access seekers such as Australia Paper, the Australian Chamber of Manufactures, the Australian Co–Generation Association, the Business Council of Australia, the Energy Users Group and Boral Energy have questioned the access code’s contestability arrangements for network augmentations and have all called for the explicit introduction of a by–pass option into the access code. For example the EUG submitted (sub. p. 79):

> One key way to help ensure more equal bargaining positions in negotiations on network services — and to introduce further contestability — is to allow for the right of new entrants and customers to construct alternative facilities, the so-called right of network ‘bypass’. This provides for much more effective negotiations on access by allowing the network user to apply a threat of competitive bypass where access charges are exorbitant, where onerous terms and conditions are being imposed or where negotiations are being thwarted by the NSP.

The Snowy Mountains Hydro–electric Authority (sub. p. 9) also called for by–pass and requested greater contestability, when it argued that:

> The code should not preclude other participants from building extensions to the network or by–passing part of an existing network. Where possible the network owners should be exposed to competition.

The EUG also strongly endorsed contestability in network provision, while noting that the opportunities for contestability would be limited given the economics of networks and the network pricing proposals.

5.2.4 The Commission’s considerations

Augmentation has a central role in ensuring that electricity networks are able to respond to the ever growing demand for electricity and new connections. Augmentation is also important to maintain adequate levels of system security and supply standards. Meeting these objectives requires balancing the interests of facility owners, access seekers and the wider Australian community. The access code’s approach has been to place certain obligations onto facility owners but also to ensure that any negative impacts of new augmentations are identified before they unduly affect the performance of the network.

The Commission believes that the access code acts in the interests of network users by obliging facility owners to augment networks to facilitate the connection of an access seeker with whom the NSP has a connection agreement. The Commission believes that this is a necessary part of the access code as the local NSP is likely to have a monopoly on augmentation of the network in their area. If they were to refuse to augment the network they could effectively deny access. Thus this obligation on NSPs is in the interest of those seeking access and the public interest generally in facilitating competition in other markets.

In order to provide some balance to this potentially onerous obligation, the Commission believes that the access code acts in the interests of facility owners by not placing an unlimited obligation on facility owners to expand their networks. Moreover, the access code acts in the interests of interconnected NSPs and network users by obliging NSPs to notify NEMMCO (with a written report) of any impact an augmentation might have across regional boundaries.

The Commission believes that the access code acts in the interests of network users by requiring an NSP not to implement a connection agreement if it will impact on the quality or security of network services to other network users. Consequently, existing network users are protected from the uncontrolled negative impacts that could eventuate from new augmentations.

However, the Commission believes that the interests of network users and access seekers would be further promoted if the code included additional incentives to ensure that network augmentation is undertaken at least cost. To a limited extent, this is already an option as NSPs can choose embedded generation options over network augmentation and they can choose to contract out the building or planning of an augmentation. More broadly however, contestability of network augmentation to facilitate a new connection should allow the party seeking connection to choose who will provide the augmentation, including an option for the access seeker to retain ownership of the augmented assets. It still remains that the relevant NSP would have control over the technical aspects of any connection into its network and as such will still be involved in the planning and testing of the augmentation.

The contestability of augmentation is an extension of the network by–pass option which, as was discussed in the previous chapter, places yet another pressure on NSPs to minimise the cost of network connection. In this context, the code has been amended to clarify that there is nothing within the access code which limits the ability of participants from bypassing existing networks.

5.2.5 The Commission's findings

The Commission accepts that the obligation placed on NSPs by the access code in relation to augmentation arising from new connections or modifications to existing connections is fair and reasonable and is accepted as part of the access code.

5.3 Network planning within a region

5.3.1 Issue for the Commission

In a competitive market, rivalry will normally ensure that firms are unable to take advantage of bad investment decisions. On the other hand, a monopolist can increase returns by taking advantage of their dominant position in the market. For instance, it could be anticipated that a monopolist might engage in strategic behaviour in some circumstances by constraining capacity while in another set of circumstances by 'gold plating' investments.

Given these incentives to act in a potentially inefficient manner, the access code requires NSPs to undertake an annual review to identify the need for future network augmentations. The annual review must involve public consultation with users and transparent assessment procedures. These reviews complement the access code's pricing regime which also act to limit over investment in network facilities (see chapter 3 for a discussion of those issues).

In general, the issue for the Commission centres on the likely effectiveness of the proposed arrangements. In particular, the access code's proposed arrangements raises a number issues for NSPs, network users and the public, for instance:

- What is the appropriate balance between network augmentation based on global planning as against market signals?
- How is an NSP's performance affected by a requirement to undertake an annual review?

- Does this code requirement place very little additional burden on the NSP as it encompasses the business planning and investment analysis that an NSP would undertake in their normal course of business? or
- Does the access code impose an obligation that is not in the legitimate business interests of those providing access?

■ What role should a NSP play in the annual planning review?
- As the NSP is both the owner and planner of their network they should be in a good position to assess investment proposals; and
- Are the planning procedures sufficiently transparent and accountable?

■ Can affected parties dispute the need for, or size of, any augmentation?

■ Should the augmentation resulting from this process be contestable?

5.3.2 What the applicant says

The access code provides for an annual planning review to be conducted by the relevant Transmission NSP in conjunction with each Distribution NSP connected to the transmission network within each region. The annual review examines the future operation of the network including forecast loads, generation and transmission developments. The access code stipulates that the annual review, and subsequent planning processes, must be public processes. For example, when a review identifies the need for network augmentation, the NSP must prepare a report that is to be made available to affected code participants which:

■ includes assessment of all identified options;
■ includes details of the NSP's preferred proposal;
■ summarises the submissions from the consultations; and
■ recommends the action to be taken.

A network user can dispute the NSP's recommendations if the proposed augmentation is likely to change its use of system charges by more than 2 per cent at the date of the next price review. If the NSP implements a generation option, in preference to network augmentation, the generation unit must be identified as periodically providing network support. The NSP can use the cost of such network support services to calculate transmission and distribution service prices.

The applicant did not comment on the potential benefits of these arrangements to either NSPs, network users or the wider Australian community.

5.3.3 What the participants say

The EUG (sub. p. 78) submitted that while users would prefer that market participants made the network planning decisions they accepted that:

> ... a degree of central co-ordination is inevitable given that the NEM must to some extent be run as a single system and therefore involves externalities. We therefore support those aspects of network augmentation, such as public consultation, mandatory consideration of generation and demand-side options, competition for network service provision and an augmentation evaluation criterion of net customer benefit, which will provide for some level of competition and transparency and provide some constraint on central planning processes.

However, TransGrid raised a number of concerns with the access code's proposed augmentation planning processes. First, TransGrid (sub. p. 7) argued that as community and environmental processes differ in each State, network development will not proceed on the same basis across the NEM.

Second, the access code should reflect economic cost effectiveness reflecting both network prices and service quality and should include uniform assessment criteria (eg cost of unserved energy and discount rates).

Third, as network planning will impact on use of system prices, it is possible that one customer could be advantaged while at the same time another is disadvantaged. TransGrid indicated that achieving consensus among participants will be difficult and the access code is silent on how consensus is to be reached.

5.3.4 The Commission's considerations

The access code's requirement to jointly plan network augmentation will ensure that in a more competitive market framework, a network within a region will continue to be planned as if it were a single network. It can be expected that network owners will benefit from coordinated planning by knowing not only of future network needs that come from within its network but also from the demand placed on it from other interconnected networks. While an NSP left to its own devices may opt for different review processes, the code requirement to undertake within system reviews of network augmentation will largely be part of the normal operations of a NSP.

The interest of access seekers is also served by the network being treated as a single entity. This is because access seekers want access to the network service at a particular connection point, they would not wish to be denied access due to ineffective or uncoordinated planning on the part of the NSP.

On balance, making this type of augmentation contestable is unrealistic as augmentation in this process is likely to involve numerous affected parties and is most likely to be well within the existing meshed network. However, as augmentation may lead to an increase in network charges, the augmentation process should be both transparent and accountable.

The public interest is served by the process being open to interested parties and not just those directly affected. Overall the process is transparent.

Those seeking access should not only have input into the decision to augment the network but also have the power to appeal any decision. A potential problem with the access code is that the scope to appeal such a decision is quite limited. This is because the access code's network pricing provisions prevents use of system prices from increasing by more than 2 per cent per annum over the average for that region. However, the access code's within region network planning provisions limits appeals to occasions where the network charge is to change by more than 2 per cent.

In relation to distribution, the access code allows jurisdictional regulators to limit the change in distribution use of system charges. Thus a similar limit could also occur in relation to distribution. Thus the potential to introduce a lack of accountability in the process means the interest of those seeking access may not be well served. NSPs may augment the network and increase charges with only limited accountability, excepting the possibility of heavy–handed regulatory intervention in relation to changes in the regulatory asset base of the NSP.

5.3.5 The Commission's findings

The provisions relating to the requirement on NSPs to undertake a review of its network in a coordinated fashion with other NSPs are in the public interest and are accepted by the Commission as part of the access code. As the public process that is to follow the identification of augmentation options is transparent and inclusive the Commission accepts it as part of the access code.

5.4 Inter-regional Planning Committee

5.4.1 Issue for the Commission

The issues associated with the Inter–regional Planning Committee's (IRPC) augmentation review are similar to those issues raised in the context of the NSP's annual review discussed in the previous section (5.3). For instance: What is the appropriate balance between network augmentation based on global planning as against market signals? Does the planning review place unnecessary burdens on NSPs or does it mimic what NSPs would do in any event?

Does the review mechanism ensure that the network augmentation processes are both transparent and publicly accountable?

In addressing these issues in section 5.3, the Commission generally accepted the applicant's arguments and concluded that the proposed public review processes by the NSP was in the public interest. However, the IRPC review process raises a number of separate issues:

- Are the across system issues significant enough to necessitate that the review be conducted by an 'outside' body; that is, not by the NSPs as is the case with internal system reviews?
- Does such a review duplicate other internal and public review mechanisms?
- Will the members of the IRPC have the necessary technical skills to conduct such a review?
- Will the IRPC members be independent, and their assessment procedures sufficient, to ensure that the augmentation process is transparent, accountable and contestable?
- Which interested parties will have representatives on the IRPC?

Also at issue is the substantial power NEMMCO has in the planning process, including decisions on whether a new interconnector should be regulated or non–regulated or whether it is justified.

5.4.2 What the applicant says

The access code establishes the IRPC to act as NEMMCO's advisory body to undertake system wide annual network planning reviews. The IRPC will also assess all applicants wanting to establish a new interconnector. The IRPC will consist of a NEMMCO representative as Convenor, representatives from each jurisdiction responsible for transmission system planning and other appropriately qualified persons chosen by NEMMCO.

The system wide annual review occurs at two levels. First, NEMMCO (assisted by the IRPC) must make an annual statement of opportunities by reporting on: the performance of the existing transmission systems; power transfer capabilities between and within transmission networks; and the adequacy of transmission systems to meet the forecast power transfers over the subsequent ten years.

Second, the IRPC must undertake an annual power system planning review. The IRPC review must:

- take into account forecasts, submissions, load growth scenarios, alternative sourcing options (eg generation, energy storage or demand side responses), committed investment projects (either network augmentation or alternatives), and any applications for new or upgraded interconnectors;
- identify the significance of future network losses and power transfer constraints (within and between networks);
- identify and assess options to reduce or remove network losses and power transfer constraints (including new transmission lines, demand side or generation options);
- assess transmission network augmentation options submitted by a transmission NSP; and
- establish a periodic review of options to remove or reduce network constraints.

The IRPC must seek public comment when its annual review has identified a network augmentation option. The IRPC's assessment of augmentation options must aim to maximise net benefits to customers.

Based on this review process, the IRPC must make recommendations to NEMMCO on options to remove or reduce network constraints. When assessing the IRPC's recommendations, NEMMCO:

- may require the IRPC to undertake further analysis or commission an independent analysis;

- must determine whether augmentation is justified on the basis of maximising net benefits to customers and without reference to its inter-regional hedge contracts; and
- must publish certain material to support its determination.

In support of the proposed arrangements, the applicant (sub. p. 139) indicated that the IRPC's assessment criteria are designed to ensure that the:

> ... interests of existing and potential network users are taken into account in planning the development of the shared transmission networks across the market.

In addition, the code requires NEMMCO to conduct its decision making functions in the public interest and in a transparent fashion. The applicant (sub. p. 226) also argued that:

> In the absence of a coordinated transmission planning process, the quality of supply to existing and new network users cannot be maintained.

The access code also prescribes that a justified proposal is to proceed either on the basis that:

- the NSPs whose networks would require augmentation may arrange for the augmentation project to be undertaken and the cost of the relevant assets be included in the determination of the revenue cap in accordance with the access code's pricing regime; or
- if the relevant NSP declines to arrange for the augmentation to be undertaken, NEMMCO must mediate and liaise with the relevant jurisdictional regulator to resolve the dispute.

In performing its functions, NEMMCO is strictly limited to making determinations only and is not permitted to call for tenders to invest in network assets.

If NEMMCO determines that an augmentation is not justified, then the relevant NSP may arrange for the augmentation project to be undertaken and, to the extent that the augmentation will provide regulated services, the cost of the relevant assets are to be included in the determination of the revenue cap in accordance with the access code's pricing regime.

A determination by NEMMCO that an augmentation is or is not justified is a reviewable decision if a party wants it reviewed by the National Electricity Tribunal.

5.4.3 What the participants say

Participants' comments on the code's proposed IRPC reviews of network augmentation focussed on two main areas: first, the potential conflict of interest arising from NSP membership on the IRPC; and second, lack of clear guidelines on how the IRPC will assess network augmentation proposals vis a vis alternatives (eg generation and energy efficiency).

A broad range of participants, such as the Victorian distributors, VPX, the National Farmers Federation and the EUG, questioned the proposed membership of the IRPC and argued there existed a potential conflict of interest. For instance, VPX (sub. p. 1) argued that in:

> ... executing their roles as network ***planners***, the regional network ***owners*** represented on the Inter-regional Planning Committee face a potential conflict of interest: that they may have competing obligations under the code to minimise network costs to users (by optimising the level of investment in new transmission assets) but they also have an obligation to their shareholders to maximise the value of their own businesses.

Moreover, VPX (sub. p. 3) questioned whether the IRPC processes contained sufficient checks and balances to ensure that the commercial interests of network owners do not come into conflict with the IRPC's obligations to make their augmentation assessments on the basis of maximising the net benefits to customers criteria.

VPX (sub. p. 3) argued that these concerns will be of increasing significance as it is likely that the NEMMCO approval process (via the IRPC) will be the only way that NSPs will seek network augmentations in the future, as any such investments will be protected from asset revaluation by the price regulators.

In attempting to address this potential conflict of interest:

- VPX suggested an alternative structure and organisation to transmission planning where network ownership and planning are completely separate;
- the Victorian distributors suggested that, to avoid any conflict of interest, the IRPC would be better constituted as a NEMMCO sub–committee;
- the National Farmers' Federation argued that the IRPC be made–up equally of representatives of industry and interested users as well as NSPs; and
- the EUG also argued that users should have representation on the IRPC as consultation alone would be insufficient.

Concerns over the code's proposal that the IRPC would assess network augmentation options vis a vis generation and demand side options were raised by the South Australian Government, Environment Australia and Greenpeace.

Environment Australia (sub. p. 9) argued that even though the IRPC is required to consider alternatives to network augmentation, the assessment should be based on the 'least cost' methodology. Consistent with this view, Greenpeace argued that the planning aspects of the code should reflect the position that that energy efficiency measures are in competition with network augmentation options.

Somewhat more specifically, and related to the above concerns about possible conflicts of interest, the South Australian Government's concerns were in the context of interconnections. The South Australian Government (sub. p. 27) argued that since interconnections are in direct competition with generators:

> ... it is not clear how the relative merits of generation and transmission alternatives are to be assessed in the deliberations of the Inter-regional Planning Committee. In particular, as there is no comparable generation planning process which can be used as a source of relevant information it would appear to be necessary to give consideration to the requirements of generators for appropriate participation in the process.

VPX goes on to submit that there are significant benefits to be derived from increasing the level of contestability for the right to both execute and own transmission augmentation projects. They believe this can be achieved if network planning and network owning are separated.

The BCA argue in relation to inter–regional connections that these are impeded by the absence of by–pass rights in the access code.

5.4.4 The Commission's considerations

As with all of the code's administrative bodies, independent membership of the IRPC is important to ensure that no single interest is favoured over another. At the same time, the members of the IRPC should possess technical expertise to ensure they provide competent advice on system wide augmentation. These are likely to be competing objectives as there may be only a limited field of people who are interested in being a member of the IRPC, are technically competent and will be an objective participant in the IRPC's deliberations.

The code requires the members of the IRPC to be appointed by NEMMCO and by jurisdictional Ministers. While the jurisdictional nominees will come from organisations responsible for transmission system planning, the ability of NSPs to unduly bias the determinations of the IRPC is constrained by the appointment mechanism. Consequently, it is the responsibility of NEMMCO and the jurisdictional Ministers to ensure that their nominees fulfil their duties in an independent and technically competent manner. In arriving at this conclusion, the Commission attaches particular significance to the fact that all transmission system planning bodies are publicly owned and therefore they, and their employees, are subject to performing their duties in a way which is, at least, consistent with the public interest.

Nevertheless, the Commission notes that this link may be weakened at some point in the future given the recent trend towards the privatisation of publicly owned bodies. In the event that further NSPs are privatised and that system planning responsibilities are retained within the privatised NSP, the Commission shares participants' concerns regarding the likelihood that members of the IRPC will act in the commercial interests of NSPs and not in the broader public interest.

One option suggested by participants was to separate the network planning functions from the network operation functions. While this approach has some appeal, issues relating to the structural reform of NSPs are beyond the scope of this review and are the responsibility of the jurisdictional governments. Nevertheless, the Commission believes that, in the circumstances described, participants have raised legitimate concerns about the membership of the IRPC. In the draft decision, the Commission stated that in order to accept the access code, it was seeking a commitment from NECA to:

> **amend the code at a later date to provide scope for jurisdictional nominees on the IRPC to come from outside a transmission network planning organisation in the event that a conflict of interest is apparent**.

In submissions following the pre-decision conference, Ecogen and CitiPower supported the broadening of the IRPC's membership, with CitiPower stressing that the nominees on the IRPC must possess relevant skills and qualifications.

Apart from its membership, an equally important determinant in the quality of the IRPC's recommendations is its ability to draw on the perspectives of, and information from, interested parties. Consistent with this objective, the IRPC is required to consult widely and have consideration to a range of alternatives to augmentation. The IRPC review process is a transparent and accountable process as it is required to listen and consider all views and obtain a decision based on a 'net economic benefit test'. The requirement to include the methodology it has used in coming to a decision greatly increases the accountability of the process.

Consequently, the Commission believes that the access code requirements that the IRPC conduct its deliberations in a transparent and accountable manner is in the interests of facility owners, network users and the wider Australian community. In assessing network augmentation options, the role played by the IRPC is spelt out in the code while NEMMCO's role is less clear. Its responsibility, for releasing the statement of opportunities has merit given its role and status in the NEM. However, NEMMCO's independence in the augmentation process has been questioned. In its draft decision the Commission expressed concern that as seller of inter–regional hedges, NEMMCO can be financially advantaged by continuing constraints in the transmission system yet they are in control of the report recommending how to overcome these constraints. While the Commission's National Electricity Code Determination imposed a condition on the authorisation that the provisions of the code requiring NEMMCO to facilitate an inter-regional hedge exchange must be deleted, this does not preclude NEMMCO from performing such a role. In this event, the Commission's concerns about NEMMCO's independence are still relevant.

The statement of opportunities report raises other concerns in that NEMMCO, unlike the IRPC, is not required to look at alternatives to transmission options such as generation and/or demand management. Thus the access code places no requirement on NEMMCO to obtain a least cost solution, instead it is to look at what option maximises net benefits to customers. While the code's definition of customers is very broad, the maximising net benefits to customers criteria may not be entirely consistent with the public interest criteria which includes references to ecologically sustainable development.

Additionally the applicant has suggested that the decision of NEMMCO will protect network providers from risk of the new asset becoming stranded. While such an arrangement has merit, it should be noted that this claim is not entirely consistent with provisions of chapter 6 (network pricing) of the access code. For instance, chapter 6 of the code gives strong guidance to the regulator to value assets in a manner which is consistent with a NEMMCO determination. However, the code provides the regulator with some degree of flexibility and to value assets on some other basis.

Reflecting these concerns the Commission stated in its draft decision that in order to accept the access code, the applicant must give a commitment to amend the code to:

- **require the IRPC to develop guidelines on how it will conduct its public consultations;**
- **provide the IRPC with the ability to indicate the relative merits of network augmentation vis a vis generation or demand side options; and**
- **ensure that NEMMCO's determination on a network augmentation includes reference to the relative merits of alternatives to network augmentation (eg. generation and demand side options).**

In its submission responding to the draft decision, TransGrid questions whether the requirements that alternatives to network augmentation be considered gave undue emphasis to generation and demand side options at the expense of other issues, such as scrutiny of market power and pool price behaviour. The EUG disagrees with TransGrid and states that new generation and demand side options are physical alternatives to network investment that the IRPC and NEMMCO should consider, whereas competitive market structure and pricing are economic objectives underlying the network planning and review process. SEQEB also supports the consideration of generation and demand side options.

TransGrid also states that the Commission's concerns regarding alternatives to augmentation are already addressed in the code and should be left open to allow NEMMCO to consider a range of matters, including the duration and severity of constraints, pool prices, market power, consequential transmission augmentations, or the relative prices or greenhouse impacts of alternative fuels. It notes that interconnection decisions will need to consider long-term effects across relevant regions and that NEMMCO will have no power to implement generation or demand-side options.

Boral Energy's submission expresses concern with the central planning role of the IRPC and argues that transmission networks should be determined on a user pays basis. Ecogen is similarly concerned about the central planning of new interconnectors and argues that interconnectors should be treated as non-regulated traders to ensure that they compete equally with generation and demand side options.

5.4.5 The applicant's response

The applicant has indicated that, in consultation with NEMMCO, NECA undertakes to promote early amendments to the code following market launch in order to address the Commission's concerns regarding: potential for conflicts of interest from members of the IRPC; guidelines on how the IRPC will perform its public review processes; and that both the IRPC and NEMMCO will take into account generation and demand side options when considering network augmentation issues.

In addition to this commitment, NECA has already amended the code to address the Commission's concerns. In particular, clause 5.6.3(b) of the code, which deals with appointments to the IRPC, has been amended by adding the following limitation on the role of the IRPC members:

> provided that a person appointed under paragraph (b) must not take part in any decision or determination of the *Inter-regional Planning Committee* where the

entity which they represent has a material financial interest in the manner to be decided or determined by the *Inter-regional Planning Committee*.

In relation to the code clauses dealing with the annual planning review of the power system's transmission networks, clause 5.6.5(f) has been amended such that the IRPC must follow the code consultation procedures:

(f) The *Inter-regional Planning Committee* ~~must call for and receive submissions from~~ consult, in accordance with the Code consultation procedures, with *Network Service Providers, Code Participants*, other *interested parties* and relevant *participating jurisdictions* ~~for~~ in relation to the assessment of particular *augmentation* options identified in clause 5.6.5(e).

Clause 5.6.5(h) has been amended by requiring the IRPC to consider alternatives to augmentation:

(h) The *Inter-regional Planning Committee* must report on the methodology used for its assessment and any alternatives to augmentation considered by the *Inter-regional Planning Committee* and it must make recommendations to *NEMMCO* on its assessment of the costs and benefits of *augmentation* options to remove or reduce *network constraints* or losses and any practicable alternatives to *augmentation*.

Clause 5.6.5(k)(1) has been amended by requiring the NEMMCO to consider alternatives to augmentation:

(b) In arriving at its determination under clause 5.6.5(j), NEMMCO must:

(1) ~~not consider any potential gains or losses to its trading in inter-regional hedge contracts described in Chapter 3~~ consider the practicable alternatives to *augmentation* including, but not limited to, *generation* and demand side options;

5.4.6 The Commission's findings

The Commission believes that the IRPC's reviews of inter-regional augmentation opportunities will promote the interests of facility owners, network users and the wider Australian community by identifying system-wide investment opportunities which may not otherwise be apparent from an NSP's, generator's or other participant's individual assessments. The outcomes of the IRPC's reviews are likely to balance the competing interests as:

- the applicant's code changes require that IRPC members must not take part in decisions where their organisation has a material financial interest; and
- the IRPC is required to undertake a transparent and accountable review process and to make recommendations based on a 'net economic benefit test'.

While this code change goes most of the way in satisfying the Commission's concerns about the potential for members of the IRPC to misuse their position, the Commission maintains its view that it still may be desirable for the code to provide scope for jurisdictional nominees to come from outside a transmission network planning organisation.

The Commission is also satisfied that the applicant's code changes meet its concerns that non-network options be considered by the IRPC and NEMMCO during the annual planning reviews of transmission networks.

5.5 Review processes for new interconnectors

5.5.1 Issue for the Commission

In addition to the three previously assessed mechanisms, the access code also provides a separate process for establishing new interconnections. A general issue is whether there needs to be a separate process for new interconnectors. If so, does this suggest problems or limitations exist in the way connection agreements are to be reached and thus the process (chapter 5.3) is unsuitable in some respect in allowing new interconnectors access?

As with the other processes there is a need for accountability. The process surrounding the establishment of an interconnector should be open to affected and interested parties. The process for approving a regulated interconnector should not crowd-out more economic alternatives which do not have the advantage of a guaranteed return. The access code could allow for a review of interconnectors however, it is important any approval mechanism is limited to ensuring any externality problem caused by interconnectors is overcome.

In this transitional phase, prior to the commencement of the NEM, the planning stages for two interconnectors are well advanced. To the extent that it may be difficult to use the code's institutions to assess whether any such interconnector should be regulated, the Commission will be looking to see whether the code's criteria have been met.

5.5.2 What the applicant says

The applicant (sub. p. 137) claimed that the IRPC would review applications for major augmentations. Consistent with this view, new interconnections must comply with the normal connection requirements (see section 4.2) and must also be assessed by the IRPC.

The applicant can request that the IRPC and NEMMCO assess the interconnection proposal according to the 'net benefit to customers' criteria. Based on its assessment, the IRPC must determine:

- the performance requirements for the equipment to be connected;
- the extent and cost of augmentations and changes to all affected networks;
- any consequent change in network service charges for other network users;
- the possible material effect of this new connection on the network power transfer capability including that of other networks; and
- whether there is a net benefit to customers from the proposal.

If NEMMCO determines that the interconnection is justified, the applicant will be invited to make it a regulated interconnection whereby it is subject to the access code's pricing regime and all consequential network augmentations will be recovered through the network service charges.

Conversely, the interconnection will be a non-regulated interconnection if, either: the application is not assessed according to the net customer benefits criteria; NEMMCO determines that the interconnection is not justified; or the applicant declines the invitation to make it a regulated interconnection. In this event, the interconnection applicant must:

- negotiate connection agreements with all affected NSPs and pay for any consequential augmentation costs (both up-front and on-going costs);
- provide an access undertaking complying with the non-pricing aspects of the access code; and
- obtain from NECA a set of market participant rules.

The applicant (sub. p. 140) indicated that the arrangements for establishing new interconnections were designed to protect the public interest by ensuring that:

- the access code processes are not overly prescriptive;
- customers are not required to pay augmentation costs when they receive no net benefits from an augmentation; and
- an interconnector is bound by the access code's non-pricing requirements.

The applicant indicated (sub. p. 228) that:

> ... customers will not be required to pay for costs of augmentations to support access for new interconnectors when it is independently determined by NEMMCO that customers receive no net benefit for these augmentations.

NEMMCO's determination on whether a new interconnector is justified is a decision which can be reviewed by the National Electricity Tribunal. The applicant argues that this review mechanism protects the rights of an access seeker.

Queensland — New South Wales interconnector

On 28 July 1997 the applicant notified the Commission of a New South Wales derogation regarding the proposed interconnector between Queensland and New South Wales, indicating that:

> The proposed *interconnector* between Armidale in New South Wales and Tarong in Queensland, to the extent that it forms part of the *power system* in New South Wales, is deemed to be a *regulated interconnector*.

Subsequently, Queensland also included a similar derogation into the code (cl. 9.38.4).

The applicant states that the proposal to interconnect follows a feasibility study undertaken by transmission networks (ie TransGrid and PowerLink Queensland) which concluded that the interconnector is a cost effective method of avoiding construction of generation capacity, will reduce fuel costs and will increase competition in the NEM. The applicant states that a review of the study by London Economics supports the feasibility study and concludes that there are net benefits to New South Wales and Queensland and all states in the NEM including:

- avoided cost of new generation plant;
- fuel cost savings;
- shared ancillary services; and
- increased competition in the NEM.

The applicant did not directly address the public benefits that may flow from the decision to pre-empt the code processes and derogate to deem the interconnector a *regulated interconnector*.

5.5.3 What the participants say

The Snowy Mountains Hydro–Electric Authority argued (sub. p. 16) that the access code should provide a proper framework for entrepreneurial interconnectors because, without such rules, players would be unwilling to build and operate entrepreneurial interconnectors.

In a similar vein, the Tasmanian Government (sub. p. 8) argued that such a framework should be developed as soon as possible. Moreover, the Tasmanian Government added that rules should not be developed with the first non–regulated interconnection exclusively in mind and sufficient flexibility should remain for different types of interconnectors.

The South Australian Government (sub. p. 27) has also expressed concern with the arrangements for potential new interconnectors and the role of NEMMCO in the process.

Queensland — New South Wales interconnector

The derogation to deem, as regulated, the Queensland to New South Wales interconnector, caused participants to question whether the interconnector needed to be regulated. In general, this concern was prompted by other concerns relating to the processes used to analyse the viability of the interconnector and whether the beneficiaries pay for the interconnector.

In general, participants' concerns did not focus on the need for the interconnector, but whether the interconnector needed to be regulated. For instance, the EUG (sub. p. 7) recognised the interconnector's role in facilitating Queensland's participation in the national market, but did not agree that it must necessarily be a regulated interconnector. Similarly, Australian Paper (sub. p. 1) supported the physical interconnection but stated that 'there is no evidence to substantiate that the merits of this interconnect have been tested against alternatives.'

To a large extent, the questioning of the need to regulate the interconnector has been prompted by the nature of the regulatory mechanism which effectively underwrites the investment and allocates costs to users. For instance, participants, such as the ACA, Capral Aluminium and the EUG, questioned the processes that led to the decision to build the interconnector. For instance, the EUG (sub. p. 7) questioned whether the networks consulted with interested parties on generation and demand side alternatives (as will be required in the future by the code) and complained that a cost-benefit analysis of the project had been withheld from the public. The EUG (sub. p. 8) stated that:

> ... the market should be given the opportunity to provide the least cost option for addressing Queensland power constraints through a competitive process without resorting to code derogations.

In a similar vein, the ACA was concerned about the lack of market signals to justify the capital outlays and the impact the interconnector will have on contestable, alternative options such as embedded generation or demand side responses.

Indeed, Capral (sub. p. 2) argued that the derogation 'effectively prevents independent assessment of whether the investment is justified and in the interests of customers in both States.' Capral indicated that this concern is aggravated by the fact that:

> ... since the National Code imposes almost all network charges on customers (rather than on generators), customers in New South Wales will bear the cost of the New South Wales share of the cost of interconnection when it is the New South Wales generators who gain the benefits.

This concern was echoed by other participants, such as Australian Paper (sub. p. 1) which argued that it does not:

> ... support the concept that the electricity users in New South Wales should subsidise the New South Wales generators' ability to sell their product into Queensland. If the interconnect is regulated (rolled into the TransGrid rate base) then transmission cost for all New South Wales users will be increased with no benefit to New South Wales electricity users.

Australian Paper argued that in order to send the appropriate locational signals and while electricity flows are north-wards, the New South Wales generators should pay for the New South Wales costs of the interconnect whilst Queensland's interconnect costs should be rolled in to PowerLink costs and passed on to Queensland consumers. Similar concerns were voiced by Boral (sub. p. 2) which noted that in Victoria, it is proposed that a separate tariff be used for a gas interconnector.

5.5.4 Issues arising from the draft decision

In its draft decision the Commission indicated it was not prepared to accept as part of the access code the derogation to deem, as regulated, the proposed interconnector between New South Wales and Queensland and New South Wales.

At the pre-decision conference a number of matters regarding the derogation were raised, including:

- the adequacy of the processes leading to the planning of QNI;
- the timing of the proposal;
- whether QNI is needed; and
- if needed, whether QNI should be regulated.

On the issue of process, the New South Wales Government representative stated that the QNI process has been under way for seven years and is supported by numerous studies. The most recent study by London Economics was undertaken because NEMMCO was not in a position to implement the code consultation procedures. Deeming QNI as a regulated interconnector would resolve the issue of revenue uncertainty for the investors (PowerLink & TransGrid).

The New South Wales Government representative noted the concerns of a number of participants, emphasising that QNI will still be subject to the risks and discretions of the regulatory process as set out in the code. Its benefits are estimated at $600-700 million in avoided cost for generation, reserve and fuel, and these benefits will be shared by New South Wales and Queensland. Transmission prices may increase by around 3.6 per cent in New South Wales. Spot prices are not likely to increase. The London Economics study concludes that alternatives are complementary to QNI but are not viable substitutes.

The Queensland Electricity Reform Unit (QERU) made a number of points regarding alternative electricity supply options. QERU stated that Queensland requires additional generation because the State is facing four per cent annual demand growth. When the Eastlink proposal failed, generation tenders were sought and twenty bids were examined (coal, gas, hydro, cogeneration) out of which came three generators (744MW) at Yabulu, Oakey & Mt Stuart. The maximum amount of demand side management proposed was 40MW. Further, QERU stated there has been an extensive process of consultations, briefings, and inputs which have been more detailed than the code requirements. Options of multiple corridors were examined. QERU also noted that increasing the size of QNI involves a major cost increase (from $450 million for 1000MW to $1.1 billion for 2000MW). Studies show minimal technical impact on Victoria and South Australia.

At the pre-decision conference, BCA/EWG stressed the importance of full information disclosure and public scrutiny of the arguments supporting QNI. The Institute of Public Affairs advocated that the issue should be referred to customers, not governments, to ensure the right incentive drivers are in place and so the cost of QNI and its approval is borne by those who will benefit from it.

Ampol argued at the pre-decision conference that the London Economics figures are not convincing (eg differing treatment of public and private capital risks) and that, while the benefits of QNI go to generators, the costs will be carried by customers through a higher revenue cap. Ampol recommended that QNI should not be permitted to be a regulated interconnector, but should only go ahead if price differences between the two regions were sufficient to support an entrepreneurial interconnector.

Additional written submissions

Following the pre-decision conference a number of submissions were received by the Commission, elaborating and emphasising positions put at the pre-decision conference.

In their submission Integral Energy states that an interconnector should only be deemed regulated if the parties can demonstrate a net customer benefit, otherwise DBs face increased TUOS charges (which will be passed on to their customers) and generators benefit from assets without contributing to the cost of the asset.

Ampol states in their submission that, as an informed first tranche customer in New South Wales, they were not consulted regarding QNI, they did not see any calls for submissions and do not believe that QNI can be justified under the code processes. Further they note that the benefits of QNI flow to generators and the costs are imposed upon customers.

The EUG argues that due process has not been undertaken, and alternatives to QNI have not been adequately assessed. It notes that costs to customers have been flagged at 3.6 per cent and seven per cent of TUOS in New South Wales and Queensland respectively, although any benefits are theoretical and dependent on modelling and assumptions.

Similarly, the ACA states that they do not consider due process has been undertaken as insufficient information has been provided to adversely affected parties (electricity consumers in New South Wales and Queensland and potential proponents of generation in Queensland), and insufficient time has been given to consider the London Economics report. Further, it states that the London Economics report may be flawed in its assessment of benefits (and in the underlying assumptions). The ACA also states that deeming QNI to be regulated raises competitive neutrality issues, as it will compete with local generation but the owners receive a regulated return on the asset and pass through the risk to consumers. The ACA also contends that generators should pay for the cost of the asset, rather than New South Wales customers.

A further submission from the ACA was received in response to consultations held by the ERTF. The ACA's submission raises questions regarding the validity of the modelling undertaken by London Economics, including assumptions regarding pool price levels and long run marginal costs of generation. It states that the cursory treatment of demand side alternatives is unwarranted as the tendering process was not conducive to demand side response. The ACA also questions the quantified savings of reserve plant and the time pressures claimed by New South Wales. It also states that it has had no chance to discuss alternatives to TransGrid/PowerLink being the builder/owner/operators of QNI and raises the issue of whether some of this work is being made contestable.

Boral made two submissions regarding the QNI derogation. It contended that including QNI in the asset base of the transmission NSPs is an inappropriate manner for costs to be recovered and will result in cross subsidisation, removal of market risk to the owners and distortion of price signals. Boral also contended that the proponents of QNI have not presented any new information to the Commission which would enable the Commission to alter the position it took in the draft decision. Boral argued that by accepting this derogation the Commission would in essence be taking on the roles of both the IRPC and NEMMCO. Boral suggests that delaying the decision on the regulated status of QNI would enable the NECA review to be finalised and the outcome of the review, if the incidence of TUOS charges is altered, may allay the concerns of some customers.

In their submission BCA/EWG raise concerns regarding:

- the incidence of the costs and benefits of QNI;
- the length of time required to generate sufficient benefits to exceed the costs;
- the magnitude of the increase in transmission costs;
- the lack of robustness of economic and other assumptions;
- a tendency to try to overcome problems with the market trading system through building QNI to enlarge the market; and
- the independence of London Economics who act as primary consultants to the Queensland Government on electricity matters.

The BCA/EWG notes that previous interconnectors have been subject to much more extensive public scrutiny.

Westcoast Energy presents a number of criticisms of the London Economics report in their submission, including many of the assumptions underlying the results and also raises concerns regarding the need for the derogation, and the effects on TUOS charges.

In its submission, Ecogen Energy argues that interconnectors should be treated as non-regulated traders, buying and selling between regions, and earning economic rents according to the power flows across QNI. Such a process will allow an interconnector to compete on an equal basis with generation and demand side options, rather than shifting the risk onto customers as is presently the case if an interconnector is regulated.

The proponent's submission provides further detail on the processes followed, benefits from QNI, the need for the derogation and a justification for having a regulated interconnector. The information presented is discussed further in the Commission's considerations section below.

5.5.5 The Commission's considerations

The Commission believes that the code requirements for interconnections represents a reasonable balance between the interests of facility owners, network users and the broader Australian community. On the one hand, the code includes assessment procedures whereby a facility owner can establish an interconnection where there are demonstrable benefits. Conversely, the proponent has the ability to establish an interconnection irrespective of the views of the IRPC and NEMMCO, but in that case they will have to contribute to the necessary system augmentations and will not be guaranteed a return on their investment. Moreover, as interconnectors can be viewed as competitors with generation, a reasonable case can be made that they are not natural monopolies and therefore should not be a regulated entity by default. Conversely, interconnectors may possess market power where there is limited contestability in the generation sector of one of the interconnected regions.

Given there is some uncertainty about the market power an interconnector may possess, the access code's flexibility in imposing regulatory requirements on interconnectors has considerable merit. Therefore in terms of fulfilling their obligations under the NEM code, it is reasonable for the access code to allow interconnectors to lodge undertakings which exclude the chapter 6 pricing arrangements. Nevertheless, these undertakings are designed to protect facility owners from declaration under Part IIIA of the TPA. In order to accept an undertaking, the Commission has to be confident about the procedures for determining access to a service, including the price for access. Consequently, while the access code may allow interconnectors to avoid the access code's chapter 6 pricing arrangements, the Commission will require interconnectors to include some other procedure for determining prices in order for their undertaking to be accepted by the Commission.

Queensland —New South Wales interconnector

The concerns raised by interested parties include:

- process and timing;
- whether QNI is needed; and
- if QNI is needed, whether QNI should be regulated.

The Commission has considered each of these matters in making its assessment.

Processes

The proponents argue that they are under no obligation to follow code processes, as the code does not yet take effect, and the processes they have followed reflect those that were valid at the time. However, the proponents also stated that they consider the QNI proposal would meet the requirements set out in clause 5.6.6 of the code.

As noted in the draft decision, the Commission considers that in the transition period prior to NEM commencement, to the extent possible, the processes followed by the proponents should reflect the code processes.

The Commission was concerned that the studies supporting the building of QNI were confidential, and that the London Economics review of the original work was only made publicly available from 22 August 1997. This concern was reflected by interested parties, from outside of the respective State governments or owners of the transmission assets, who stated they had not been given an opportunity to review or critique the findings. Many submissions received since the pre-decision conference also stated that the time given to consider the derogation and supporting documents had been inadequate.

The Commission notes that the QNI process in its various configurations, has been a long process, commencing some seven years ago and that the proponents of QNI have undertaken substantial consultations. The difficulties have arisen because the constituents that are required to be consulted under the code processes are somewhat different to those that have been consulted as part of the processes 'normally' undertaken in development proposals of this nature. In response to the Commission's draft decision the proponents did undertake some further consultation with interested parties who had indicated concerns regarding QNI. However, it remains apparent that interested parties still have concerns regarding the consultation process and that the latest round of consultations is very late in the decision making process and unlikely to impact upon decisions made by the proponents. Nevertheless, the Commission considers that interested parties have now had sufficient time to consider and comment upon the derogation.

Timing

The issue of the timing of QNI was raised in several submissions, with many interested parties claiming that the time lines set out by the proponents still allow ample time for code processes to be undertaken, or for the code requirements regarding unregulated interconnectors to be developed. Further, by not allowing the derogation at this time, interested parties argue that decisions regarding the regulated status of QNI would be made after the finalisation of the NECA review of transmission pricing, the outcome of which may alleviate concerns regarding the payment for QNI by customers or generators through TUOS charges.

The proponents of QNI indicate that in order to have QNI operational by 2001, they need the economic basis for QNI to be established by early 1998. The underlying economics will form part of the Environment Impact Statement (EIS) process which must be completed by November 1998, in order for contracts to be put in place and construction to commence. The proponents state that in order for the construction of QNI to be complete by 2001, they cannot suffer the delay of waiting for NEMMCO and the IRPC to be established and gain legal jurisdiction over the decision regarding regulation of QNI.

QERU has further added that the construction of the interconnector by 2001 is seen by the NCC as a necessary condition for competition payments to Queensland. Lack of compliance with this timetable would be considered evidence of a lack of completion of a National Competition Policy commitment. QERU suggests that the NCC views the interconnector as of national significance. QERU also states that any delay to commencing QNI will mean that the interconnector will not be ready when required, forcing Queensland to build generation capacity. QERU states that in such an event the interconnector would then be delayed for a lengthy period of time as any generation investment is likely to be baseload plant and this has implications for the market reform strategy being pursued in Queensland and could result in many of the benefits of reform not being achieved.

Based on the information provided by NEMMCO and the proponents of QNI, the Commission accepts that the proponents of QNI must derogate to have QNI deemed a regulated interconnector. The Commission accepts the statement from the proponents that a decision on whether or not QNI is to be a regulated interconnector is required early in 1998 to feed into the EIS process. Delaying the assessment of QNI until after market commencement would delay the process beyond what the proponents have indicated is manageable.

In their supplementary submission the proponents claim that a derogation from the code processes is required because the code processes are unavailable to the proponents of QNI. The Commission has received confirmation from NEMMCO that this is the case. NEMMCO has advised that:

- it will not be in a position to formally conduct the processes set out in clause 5.6.6 of the code until the commencement of the NEM;
- while transitional arrangements are in place, these are fully committed and are unavailable until late January 1998. Any interim review of QNI could not be complete until May 1998; and

- the transitional arrangements are not as detailed as those set out in the code and do not extend to the level of consultation envisaged under the code.

NEMMCO also comment that it is aware of the processes followed for QNI including:

- the determination of the costs and technical capabilities of various interconnection options;
- the economic evaluation of interconnection options versus alternative generation expansion programs; and
- consultations with interested parties.

NEMMCO concludes that "this evaluation process followed by the New South Wales and Queensland jurisdictions is consistent with the process that NEMMCO would propose to undertake".

Is QNI necessary

Several submissions from interested parties raise concerns regarding the assessment of the benefits stemming from QNI, as put forward in the London Economics report. The Commission is not in a position to determine the veracity or otherwise of the details of the London Economics report. Moreover, as noted above, the Commission is not performing the tasks of either the IRPC or NEMMCO, and it does not consider that its role in accepting the access code is to assess the costs or benefits of building QNI. However, the Commission, as regulator of transmission networks in New South Wales and Queensland from 1999 onwards, will have to form a view on the value of the assets of the owners of QNI.

Should QNI be regulated

The Commission sees considerable merit in the code requirements as they set down clear processes and criteria for establishing regulated interconnectors. Moreover, these processes establish an ex-ante discipline on the investment decisions for regulated interconnectors which will generally compete with contestable generation and demand side alternatives. These processes are important as the risks faced by a regulated interconnector, with a stipulated return, are likely to be considerably different to the risks faced by a firm operating in a competitive market. However, this does not mean that there are no ex-post disciplines on an investment decision for regulated interconnector as the regulator still has the ability to optimise a network's assets.

Boral, the EUG, Westcoast Energy, BCA/EWG, ACA, Ampol, and the incumbent New South Wales DNSPs raise the issue of the incidence of the costs of QNI, compared to the probable incidence of benefits — ie New South Wales end use consumers will pay for QNI assets through their TUOS charges, whilst New South Wales generators and Queensland customers will benefit from a larger market and lower prices, respectively.

The proponents note that the incidence of benefits is not clear cut, and it is expected that there will be considerable flows across QNI in both directions. Therefore, they reject the contention that the benefits will be limited to Queensland customers and expect that there will be benefits to New South Wales customers as well.

The Commission accepts the proponents view that flows may be north or south, depending upon market conditions in both states. With regard to the incidence of TUOS the Commission notes that the effect of this derogation is not to guarantee the proponents of QNI the income stream necessary to make the investment viable. By deeming the QNI asset to be regulated they will be subject to the same methodology that applies to all regulated transmission assets.

As discussed in chapter 3 of this report, the Commission has considerable concerns about the efficiency signals associated with the code's network pricing arrangements. As evidenced by participants' concerns, these efficiency signals will be lacking even more in the period prior to any inter-regional transfers of network charges (see clause 6.3.4 of the code). The

Commission has signalled that it expects the NECA review to consider the incidence of TUOS charges. Changes to the incidence of TUOS charges and commencement of inter-regional transfers will address many of the interested parties concerns regarding whether the beneficiaries of QNI will be required to fund the investment.

Further, the Commission, as regulator of transmission assets in New South Wales from 1999, will have responsibility for assessing the asset base of TransGrid, including assets associated with QNI.

The regulated income stream that TransGrid earns will depend upon the Commission's assessment of the optimal value of those assets. As regulator the Commission may form a view that the value of the QNI assets is considerably less than the costs of construction.

The Commission considers that the regulatory process, in particular the process of an independent regulator optimising the assets of the transmission network, provides sufficient protection to all market participants regarding the allocation of network costs. The Commission notes the valid concerns of many industry participants but stresses that deeming QNI to be regulated does not offer TransGrid or PowerLink a risk free return on the asset, it simply ensures that the assets are regulated on the same basis as other transmission assets.

5.5.6 The Commission's findings

Given the uncertainty that surrounds the market power an interconnector may possess, the Commission believes that it is in the interests of facility owners and interconnector users for the code to be flexible in requiring compliance with chapter 6. Nevertheless, the Commission reserves its right to reject an undertaking, under Part IIIA of the TPA, if it does not include some other set of procedures for determining the price of access to an interconnector.

With respect to the Queensland to New South Wales interconnector, the Commission considers that there are public benefits arising from its development. These benefits include competition benefits arising from an increased efficiency in the use of reserve plant; a possible reduction in the degree of market power on New South Wales generators; greater customer choice and efficiency benefits arising from an integrated approach to ancillary services in the NEM.

In terms of the derogation to deem QNI as a regulated interconnector, the Commission believes that it will have benefits in the form of providing the proponents with certainty regarding the cost recovery methodology that will apply to the assets (although not certainty regarding income stream) and benefits of avoiding transaction costs associated with any duplication of processes.

With respect to the concerns of interested parties relating to the incidence of costs and benefits flowing from QNI, the Commission contends that this issue will be dealt with in the context of optimising the asset bases of the proponents within the existing regulatory framework.

In its draft decision the Commission agreed with the concerns raised by interested parties regarding the decision making processes followed by the proponents of QNI. The Commission also indicated a preference for the code processes to be followed to the extent possible. However, the Commission has accepted NEMMCO's statement that it is not in a position to undertake these normal processes within the required decision making time lines. Furthermore, NEMMCO has indicated that the processes adopted for QNI are largely consistent with what it would have undertaken, had the transitional arrangements applied to QNI.

Therefore the Commission has decided to accept as part of the access code the derogations to deem as regulated the proposed Queensland to New South Wales interconnector. This gives the proponents of QNI sufficient certainty regarding the regulatory framework of QNI to proceed with the EIS process.

The Commission has not based its decision upon the economic merits or otherwise of QNI or alternatives to QNI. It has noted both the London Economics report and the proponents submission regarding the benefits arising from QNI and has also noted the deficiencies in both those documents as put forward by interested parties. Whether or not QNI is an efficient investment will be a matter which the Commission, as regulator, will revisit when the time comes to optimise the asset bases of TransGrid and PowerLink. The Commission notes that it is a real possibility that the asset bases of the transmission companies could be substantially devalued as part of the optimisation process if QNI proves not to be an efficient interconnector.

5.6 Information requirements

5.6.1 Issue for the Commission

Effective planning of the network will be reliant on the quality and extent of information available on past and expected future use. The gathering of information has to be balanced with the knowledge that some of the information will be commercially sensitive in nature. Given that those using the network will quite possibly be in a competitive sector there is the issue that some participants may not wish NSPs knowing their future plans, for instance, in building of new generating units. Some NSPs may also choose to enter the generation or retail sectors and thus could use this information to their advantage. This must be balanced against the need to ensure the network is adequately planned to cope with future or even current demand. The ultimate question is, does sufficient ring–fencing exist to ensure abuse of this information does not occur

Given the need for participants to provide forecast information in relation to their future use of the network the issue arises as to what modifications should the relevant NSP be able to make to the information if it believes it is incorrect? The problem with NSPs changing forecast information is that they may as network owner have a conflict on interest with their role in the planning process. The NSP could change forecast information in its own interest as network owner. How responsible, given this conflict of interest, should NSPs be if they choose to modify information that they then use to plan the network?

5.6.2 What the applicant says

Clause 5.6 outlines the planning and development of the network. Upon written notice from the relevant NSP, code participants have 40 business days during which they are required to provide the NSP with short and long term electricity generation and load forecast information in relation to that code participant's connection point to the transmission network. The information to be provided is documented in the code's schedule 5.7 and includes annual maximum active power, coincident reactive power and day of network peak summer and winter MW peak load at connection point. Each code participant is required by the access code to use reasonable endeavours to provide accurate information.

Clause 5.6.1 (d) allows the NSP to modify the forecast information that code participants provide it. The NSP is required to inform the relevant code participant that it has modified the forecast information and to provide a reason for this. The access code explicitly states that the NSP is not responsible for any adverse consequences of modifying the forecast information or for failing to modify the forecast information.

5.6.3 What the participants say

TransGrid (sub. pp. 7–8) believe the forecasting requirements in the access code are similar to those that are presently sought and received from participants and are the minimum required to adequately plan the network to meet the needs of all users. They go on to say that the access code requires this information to be kept confidential and used only for bona fide purposes by the NSPs.

The submission from the Victorian distributors (sub. p. 22) comments that information given to the IRPC by market participants has the possibility of being misused and consequentially distort market outcomes.

5.6.4 The consultant's views

Western Power's review of the technical aspects of the access code indicated that the code's requirements for the provision of forecast information should be sufficient to ensure efficient planning and development of the network. However, given the uncertainties associated with forecasting, there can be no guarantee that the data provided by code participants or the modifications made by the NSP are accurate. Consequently, unconstrained access to the networks cannot be guaranteed, especially in instances where the proposal for augmentation involves significant financial and environmental issues.

While Western Power consider that the requirement for code participants to provide forecast information does not pose a barrier to entry, it may be a burden to smaller participants with generation or load of less than 10MW and as such could be relaxed in certain circumstances.

On the issue of NSPs modifying forecast information, Western Power state that it is reasonable that the NSP not take responsibility for information it does not alter. However, Western Power consider that NSPs should take responsibility for any modifications which they make to forecast information.

5.6.5 The Commission's considerations

The requirement on code participants to provide information, including information about prospective new generation and load, has clear benefit. For those providing access it enables them to effectively plan their network and ensure access is available. For those seeking access it also provides for efficient investment and therefore appropriate charges for access and should ensure the network is able to provide for their future needs. The public interest in having information available for efficient investment decisions is also served by the access code in this respect.

It is reasonable that NSPs are not responsible for any adverse consequences if they fail to modify forecast information supplied to them by code participants. On many occasions they may not be in a position to determine the accuracy of the information. However, as the Commission's consultant indicated, concern must be raised that if NSPs do choose to modify forecast information and they are not responsible for the consequences. This could allow NSPs to inflate the estimated demands on the network so as to allow over–investment in the network. Such an action would be inconsistent with the interest of those seeking access and with the public interest generally.

In the draft decision the Commission stated that in order to accept the access code, it was seeking a commitment from the applicant that amendments would be made to:

> **ensure that network service providers are only able to modify forecast information to their own financial advantage provided it is consistent with guidelines.**

In a submission following the Pre-Decision Conference, TransGrid states that it does not support this requirement, arguing that it fails to recognise the transmission NSP's role in compiling load forecast information. It argues that the transmission NSP must reconcile the forecasts obtained from distribution NSPs and directly connected participants with the forecasts it develops in conjunction with NEMMCO and the IRPC.

TransGrid argues that distribution NSPs may have an incentive to over-state load forecasts to justify their planned network investments. The New South Wales distribution businesses reject this claim and argue that they have no incentive to inflate their load forecasts because it will increase their TUOS charges if the transmission NSP invests in new assets which are not required and require the distribution NSP to invest in new connection assets. TransGrid argues that, while it would be optimum for the process to be open, distribution NSPs have expressed concern for the confidentiality of their forecasts.

The Commission acknowledges the need for transmission NSPs to modify forecast information in certain instances and the requirement stated in the draft decision does not alter the ability of the transmission NSP to do this. The Commission is only requesting that such a modification be according to a set of guidelines which outline how and why the NSP is able to modify the forecasts. This would assist in resolving any dispute over changes to forecast information; without this it is difficult to establish on what grounds code participants could dispute modifications. The Commission is also concerned that NSPs could use forecast information to the advantage of their activities in contestable parts of the industry (eg embedded generators). While existing structural reforms have addressed this concern to some extent, the ability of regulators to develop ring-fencing arrangements governing the accounting and structural separation (including information flows) will provide an avenue to resolving this problem.

5.6.6 The applicant's response

The applicant's response to the range of matters raised in the Commission's draft decision on the access code did not address the issue of amending the code to establish a requirement for NSPs to develop guidelines on how they would amend forecast information.

5.6.7 The Commission's findings

The Commission accepts the requirements on code participants to provide information to the relevant NSP in relation to the transmission network as acceptable as part of the access code. The Commission maintains its view that clause 5.6.1(d) of the code should be amended to ensure that NSPs are unable to modify forecast information to their own financial advantage unless it is consistent with guidelines in the access code.

6. Power system security and metering

Access to electricity networks is not simply about a contract to connect and a price for that connection and use of the network. Electricity is a good that in its supply and transportation through the power system requires continual balancing to ensure it is safe and reliable. Thus, the terms of access involve technical specifications as well as a commercial connection contract and network prices. The technical specifications must be examined as part of the assessment of the wider terms of access.

To assist the Commission's assessment of the access code's system security and metering requirements, the Commission engaged Western Power Corporation (WPC) to review the technical aspects of the access code with Colin Taylor and Associates providing referee's comments. Both of the contracted consultants have significant experience in network planning and other aspects of the electricity supply industry. While they both have a background in the industry, the consultants were able to provide independent advice as neither of them are employees of organisations which will participate in the NEM at its inception.

This chapter commences with a summary of the issues which the Commission considers are important in assessing the access code's technical requirements (section 6.1). Section 6.2 examines the access code's system security requirements (chapter 4 of the code) and section 6.3 examines the access code's metering requirements (chapter 7 of the code). The assessment of both chapters of the access code draws heavily on issues presented to the Commission by its consultants.

6.1 Issues for the Commission

The Commission's approach to examining the power system security and metering chapters of the access code is largely consistent with the assessment of the network connection chapter of the code. In particular, the Commission has focused on whether the technical requirements and obligations placed on code participants reflect an appropriate balance of maintaining secure and well functioning electricity supply arrangements while not deterring entry or placing unnecessary burdens on those already operating in the market.

Entry barriers in the form of technical expertise or financial resources can exist in any industry and generally are of little concern to the contestability of a market when they apply equally to incumbents and new entrants. However, they may be a concern where the entry requirements for new participants are larger, more onerous or more time consuming than for existing network users. The Commission has paid particular attention to the potential spillover effects of the power system security requirements as they can have serious ramifications for the safety and property of all parties connected to the grid and on the ability of the system to deliver network services.

In terms of the technical metering procedures, the Commission considers it important that they facilitate a competitive metering industry which will encourage innovation and drive down metering costs. The Commission has therefore focussed on whether the code's metering requirements create an entry barrier to metering providers and agents and, if so, whether these entry barriers are non-discriminatory between existing, new and potential entrants.

The Commission has also considered whether the current metering requirements for non-host retailers will hinder competition in the retail market by imposing extra costs, which the host retailer does not have to face. The Commission has considered whether these extra costs outweigh the benefits smaller customers receive from changing retailers.

Consistent with these objectives, the main issues that the Commission took into consideration were whether the requirements in chapters 4 and 7 of the code:

- promote the public interest by not unnecessarily adding entry barriers which would reduce contestability in other markets;
- protect the legitimate business interests of:
  - existing network owners and users from potential spillover effects from the operation of new connections; and
  - future network owners and users from potential spillover effects from the operations of existing network owners and users; and
- protect the public interest in terms of increased competition, social welfare and the health and safety of the community.

To assist the Commission assess the code's technical requirements, consultants from Western Power Corporation were engaged to review whether the code:

- imposes any unnecessary barriers to those seeking entry to either the market or the network service;
- is consistent with international and Australian practices and, where differences occur, whether they could be considered improvements;
- places a burden on new network providers and new network investments;
- advantages or disadvantages current network providers; and
- allows for future development of the market including introducing retail competition and changes in the size, structure and technology of the industry.

6.2 Power system security

6.2.1 What the applicant says

Chapter 4 of the code provides a framework for achieving and maintaining a secure power system. It describes the responsibilities of NEMMCO and code participants, and the conditions under which NEMMCO can intervene in the market and issue directions to code participants. In addition, the code stipulates technical requirements relating to system security and reliability as well as connection (chapter 5 of the code).

As far as practicable, the power system should be operated so it is, and will remain, in a secure operating state. This occurs when NEMMCO is of the opinion that the power system is in a satisfactory operating state (see Box 6.1) and can be quickly returned to this state following a single credible contingency event with the frequency remaining within the operational frequency tolerance band in accordance with the power system security and reliability standards. In forming its opinion, NEMMCO must consider the impact of each potentially constrained interconnector and must use the technical envelope for determining credible contingency events.

Box 6.1: Technical requirements of a satisfactory operating state

Chapter 4 of the code details a number of the requirements for the power system to be in a satisfactory operating state, including requirements that:

- the frequency at all energised busbars must be within the normal frequency operating band of 49.9Hz to 50.1Hz, with minor exceptions;
- voltage magnitudes at all energised busbars at any switch yard or substation of the power system must be within the relevant limits set by the NSPs in accordance with the code's network connection requirements (ie clause S5.1.4 of schedule 5.1);
- current flows on all transmission lines of the power system and all other plant forming part of or impacting on the power system must be within the ratings (accounting for time dependency in the case of emergency ratings) as defined by the relevant NSPs in accordance with schedule 5.1;

- the configuration of the power system must be such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment; and
- the conditions of the power system must be stable in accordance with requirements designated in or under clause S.5.1.8 of schedule 5.1.

The access code (schedule 5.1) defines the power system performance standards to be maintained by NSPs when designing connection facilities for customers and generators. This schedule is assessed in section 4.3 of chapter 4 of this report.

If a credible contingency event occurs, or there is a significant change in power system conditions, the code requires NEMMCO to attempt to return the power system to its secure operating state as soon as practical, and in any event, within thirty minutes. The power system should have automatic load shedding facilities which will restore the power system to a satisfactory operating state following significant multiple contingency events. To fulfil its responsibility for power system security, the code requires NEMMCO to:

- monitor the power system's operating status;
- assess technical and operational constraints and the adequacy of reserves;
- advise code participants of situations which could significantly affect power system security;
- direct code participants to take action to ensure the power system is in a satisfactory operating state;
- conduct reviews of significant operating incidents or deviations from normal operating conditions;
- manage power system contingency events and electricity supply shortfalls;
- control power system frequency and voltage and ensure there are sufficient reactive power reserves; to assist in this role, NEMMCO has the authority to procure ancillary services and to control and direct the output of scheduled generating units and scheduled loads;
- protect power system equipment by: determining power system fault levels (in consultation with NSPs); coordinating the protection of transmission system plant and equipment; coordinating inspections and testing; and taking action following the outage of one or more protection systems;
- coordinate and ensure that NSPs perform the calculations necessary for the stable operation of the power system and to determine the settings of equipment used to maintain power system stability;
- arrange and endorse the installation of power system devices necessary to assist the stability of the power system as well as coordinate and supervise appropriate inspections and testing of any such devices;
- publish details of circumstances which could have a materially adverse affect on the supply to, or from, code participants and declarations of low reserve or lack of reserve conditions (or cancellations thereof); and
- produce regional load forecasts for certain periods, to give an indication of the total generation capacity required to meet the forecast load and the supply required to be delivered to the transmission network.

If NEMMCO publishes a declaration of low reserve or lack of reserve, it may intervene in the market by contracting for reserves (acting as the reserve trader), but only if there is insufficient time for the market to respond to the matter (ie section 3.12 of the code). If the latest time for intervention is reached and there is still a lack of reserves, NEMMCO may direct scheduled generators or market customers to do whatever NEMMCO considers necessary to maintain or restore the power system to a reliable operating state.

If there is a projected violation of power system security, NEMMCO may authorise a person, or authorise a person to require a code participant, to comply with s.76(1) of the National Electricity Law, and to:

- switch off or re-route a generator;
- call equipment into service;
- take equipment out of service;
- commence operation, maintain, increase or reduce active or reactive power output;
- shut down or vary operation;
- shed or restore customer load; and
- do any other act or thing necessary to be done for reasons of public safety or the security of the electricity system.

The applicant (p.143–144) states that NEMMCO's reserve trader and intervention powers are transitional measures (lasting 5 years) until confidence is gained in the ability of market based signals to deliver adequate system reserves and reduce the risk of market failure and involuntary load shedding. Prior to exercising these powers, NEMMCO must comply with the code's market intervention processes (section 3.12 of the code) unless it considers it inappropriate to do so. NEMMCO's reserve trader and market intervention powers are discussed in more detail in chapter 9 of the Commission's National Electricity Code Determination.

Black start up facilities should be available to restore power system security and, if necessary, restart generating units. Generators providing black start-up facilities under an ancillary services agreement must arrange for such facilities to be tested. Generators are required to draft local black system procedures for NEMMCO's approval and are required to arrange the testing of these procedures.

Where prior arrangements have been made, NEMMCO may give a distribution system operator directions relating to its reactive facilities in order to maintain power system security. NEMMCO may engage system operators to perform some of its responsibilities for power system security. The system operator must inform NEMMCO about: the state of power system security; present or anticipated risks; action taken or contemplated to address such risks or restore the power system to a satisfactory operating state; circumstances which may adversely affect code participants' security of supply; and the jurisdictions' priority schedules for sensitive loads and load shedding.

To further ensure the security of the power system, the code requires:

- market customers with a certain level of expected peak demand to provide automatic interruptible load to be automatically disconnected following a power system under-frequency condition (as described in the power system security and reliability standards).
- NSPs must ensure that interruptible loads are provided and must arrange appropriate systems to facilitate a load shedding and restoration process which may be necessary in the event of a prolonged major supply shortage or extreme power system disruption. NSPs must also advise NEMMCO of any ancillary services provided under a connection agreement.
- scheduled generators to:
  - ensure their generating units have responsive speed governor systems;
  - ensure their scheduled generating units comply with the latest dispatch offer;
  - comply with the conditions for sending out energy and committing and de-committing scheduled generating units;
  - comply with other dispatch related restrictions; and

- notify NEMMCO of any events impacting on the operational availability of its scheduled generating units.

- code participants to:
  - advise NEMMCO, or the relevant system operator, of circumstances which may adversely affect the secure operation of the power system or any equipment owned or controlled by the code participant or an NSP;
  - provide and maintain voice and data operational communication facilities for nominated persons; and
  - ensure that each of its facilities can comply with relevant dispatch bids.

Code participants and NEMMCO are required to act in accordance with: power system operating procedures, including NEMMCO's instructions on market and power system operations; NEMMCO's guidelines on power system security; and regional specific power system operating procedures. NEMMCO must, either directly or through a system operator, compile the regional specific power system operating procedures in conjunction with the relevant NSPs. Victoria and New South Wales have derogated from this provision of the code. These derogations, shown in Table 6.1, do not impact on NEMMCO's ability to review and update the regional specific power system operating procedures.

Table 6.1 Operating Procedures Derogations

Jurisdiction	Expiry date	Details
Victoria	not specified	The Victorian System Operating Procedures are the regional specific power system operating procedures to apply to the Victorian transmission network.
New South Wales	not specified	Network Operating Standards (New South Wales) and the System Operating Procedures (New South Wales) in force under the New South Wales Electricity Market Code are the regional specific power system operating procedures to apply to the New South Wales network.

The applicant states that the Network Operating Standards (New South Wales) and the System Operating Procedures (New South Wales) are designed to ensure that the interconnected New South Wales network operates in a safe and reliable manner. They state that New South Wales' standards have the same general effect as the schedules to chapter 5 of the code. They claim that in the event of a discrepancy between the code and New South Wales' standards, the later will prevail.

The code requires that NSPs and code participants comply with the nomenclature standards, as agreed with or determined by NEMMCO. Given that these standards are yet to be developed, the applicant has submitted a derogation which states that the nomenclature standards defined in Victoria's System Code will apply in Victoria until NEMMCO and a relevant NSP agree otherwise.

NEMMCO and distribution system operators are required to communicate concerns about the conditions of the distribution and transmission networks and give prior notice of switching operations. NEMMCO and the system operator are also required to maintain records of power system operational communication.

Chapter 4 of the code also includes provisions for installing and maintaining remote control, operational metering and monitoring devices and local circuits and operational control and indication communication facilities.

In supporting the code's power system security requirements, the applicant (sub. p. 45) stated that:

> ... the operation of an integrated power system is complex and therefore it is essential that the accountabilities and responsibilities for maintaining the system quality of supply attributes of frequency and voltage to all users and the integrity of equipment comprising the power system are clearly defined.

The applicant (sub. p. 105) argued that the code's prescriptiveness for the responsibilities and obligations of code participants helps to reduce ambiguity and makes the requirements for entry clearer and less risky to possible new entrants. Moreover, the applicant (sub. p. 222) argued that it is in the public interest for the power system to meet such quality of supply and technical safety standards. In meeting this objective, the applicant stated that the technical and operational requirements in chapter 4 of the code are consistent with good electricity industry practice and applicable Australian standards.

The applicant (sub. p. 64) also considers that the integrity of the networks is preserved by the code's system security requirements.

6.2.2 The consultants' views

The Western Power review did not raise any significant concerns with chapter 4 of the code. Indeed, the review (Western Power, pp. 13–15) concluded that chapter 4 of the code:

- does not impose any unnecessary requirements on those seeking entry;
- imposes requirements which are consistent with reasonable industry practice;
- imposes a reasonable degree of responsibility on all network providers;
- does not advantage or disadvantage current network providers; and
- will not impede future development of the market.

Western Power did, however, make a number of comments and suggestions about areas of the code that could be changed to improve its operation. First, there should be an audit of NEMMCO's ability to bypass the code's process for market intervention (ie clause 3.14). NEMMCO is required to follow these processes when authorising persons to comply with the National Electricity Law, for example, when directing load shedding or requiring a generator to be switched off. However, NEMMCO has the power to bypass the market intervention process if it considers it is appropriate to do so (ie clause 4.8.10(d)). Western Power recommends that there be an audit of NEMMCO's use of this power to demonstrate to code participants that it is not being abused or used unnecessarily.

Second, Western Power suggested that NEMMCO be required to monitor load forecasts and inform market participants of inaccuracies and deviations from predictions. This would prevent over or under commitment of generating plant in the short term and inefficient investment in generation and network facilities in the longer term (ie clause 4.9.1(g)).

Third, the Reliability Panel, on advice from NEMMCO and NSPs, could determine a standardised method of calculating current ratings of transmission lines and other plant to avoid NSPs using different methods (ie clause 4.2.2(c) & (d)).

Fourth, three phase faults may be considered a credible contingency on some parts of the power system, and therefore should be included in the code's definition of a credible contingency event. Moreover, Western Power identified an apparent conflict between clauses in chapter 4 (ie clause 4.2.3 (b)(2) and 4.2.3(e)) which exclude three phase faults as a credible contingency event, and a clause in schedule 5.1 (ie S.5.1.2.1) which includes such an event in some circumstances.

Other suggestions made by Western Power in their review of chapter 4 were to simplify and clarify particular clauses (especially 4.2.3(c) and 4.3.2(d)) and to correct typographical and cross referencing errors.

In reviewing the jurisdiction's technical derogations, Western Power advised that Victoria's and New South Wales' derogations regarding regional specific power system operating procedures are reasonable; appear in accordance with the code's intent; and provide scope for the operating procedures to be reviewed and updated by NEMMCO. However, they added that participating jurisdictions should be aiming for uniform operating procedures where possible. Western Power also advised that the Victorian derogation relating to nomenclature standards was reasonable as it provided a transition to some other standard if required.

Colin Taylor's review of the Western Power report stated there may be a need for NEMMCO to have some level of accountability to market participants for the accuracy of its load forecasts. Taylor suggested that NEMMCO could publish statistical data on the accuracy of the load forecasts and an explanation of significant errors. Taylor also suggested that:

- NEMMCO could be required to publish details of any intervention in the market, including the reasons for the intervention;
- the provision requiring code participants to provide voice and data communications equipment should only apply to participants with connections above 10MW because it may be a barrier for small participants; and
- it may need to be recognised that the requirement for generating units to have governor systems is not applicable to some forms of generation.

6.2.3 What the participants say

In addition to Western Power's quite specific concerns, the Commission's public consultations revealed that a number of participants were concerned that the NEM's system security arrangements should not be dominated by what could be described as administrative command and control processes. Rather, participants expressed a preference that, wherever possible, the code rely on market mechanisms to signal and provide the relevant services to ensure a secure system.

Comments by the Snowy Mountains Hydro–Electric Authority (SMHEA) were typical of many participants when it argued that system security standards should be in line with customers' needs. SMHEA (sub. p. 12) also argued that 'ideally, system security should be managed through a competitive ancillary services market and user pays charging of ancillary services'.

In a joint submission, the Victorian Distribution Businesses (sub. p. 17) expressed concern that NEMMCO's power to review and report on operating incidents is too broad. They argued that the code should be clarified to ensure that information obtained by NEMMCO for the purpose of this review is subject to the code's confidentiality obligations (ie chapter 8) and that affected code participants or third parties are able to review a draft of any report.

The Victorian distributors (sub. p. 18) also argued that the code should be clarified to ensure that all those operating a distribution network (not only those required to register as a Distribution System Operator) are subject to the chapter 4 rules.

The Energy Users Group (supplementary sub. pp. 4–5) submitted that it has no prima facie objection to New South Wales' operating procedures derogation, provided it is shown that the New South Wales Operating Procedures are consistent with the national code and market objectives. They state that the applicant makes no attempt to show this, and suggest that further information should be sought from the applicant.

The Business Council of Australia (sub. pp. 27–29) expressed concern that New South Wales and Victoria intend to continue to use their own system operating rules and instructions and security standards and not follow the proposed code rules. The Business Council is also concerned that the differing technical and security standards can act as a barrier to the entry of new competitors. They believe that the adoption and publication of common minimum technical and security standards is essential for a proper functioning and efficient competitive electricity market.

6.2.4 The Commission's considerations

The Commission accepts the applicant's view that it is necessary for the code to prescribe the responsibilities of NEMMCO and all code participants in an integrated electricity market. This approach protects the interests of those seeking access to the market and the wires infrastructure, as they are given certainty about the standards at which the power system will be operated and their obligations for maintaining system security.

The interests of NSPs, network users and the public are also protected by the system security requirements which promote a safe and reliable means of generating and transporting electricity, reduce the risk of a system wide disruption and which seek to restore the power system and minimise the impact after such a disruption.

While system security practices are similar across the electricity industry, there are operational differences and, as a result, currently there are no industry wide standards. The code's power system security requirements attempt to promote the interests of NSPs, network users, the public and potential entrants by codifying a set of practices which are generally consistent with those used throughout the industry.

In the draft decision the Commission accepted Western Power's conclusion that the power system requirements do not disadvantage new NSPs relative to incumbent NSPs. The Commission stated that while the requirement for code participants to provide load forecast information may be viewed as a disadvantage to new entrants because of the set up cost, the ongoing costs of providing this information should be small and it is likely that participants would need to produce this type of information for use in their business.

Despite these desirable features of the code, the Commission indicated in its draft decision that it would be in the interests of all parties to further improve the clarity and operation of the code by reconsidering the suggestions and recommendations made by the Commission's consultants and industry participants. The Commission acknowledged that many of these issues were considered in preparing the code, however it concluded that it is necessary for the applicant to revisit them in light of the consultants' comments. For instance, the Commission acknowledged that the code's present definition of a credible contingency event is consistent with the practice in eastern states, which has delivered quite high levels of system security. However, given the technical nature of consultants' and participants' suggestions, the Commission stated that it was inappropriate for it to assess the merits of suggestions to change the code's system security requirements. Rather, the Commission recommended that, at an appropriate time after commencement of the market, NECA should refer the following issues to the code change processes:

- **requiring an audit of NEMMCO's ability to bypass the process for market intervention when authorising persons to comply with the National Electricity Law;**
- **requiring that NEMMCO publish the reasons for, and details of, any intervention in the market;**
- **requiring that NEMMCO monitor load forecasts and inform market participants of inaccuracies and deviations from predictions (this could be done by publishing statistical data on the accuracy of the load forecasts and an explanation of significant errors);**
- **requiring that the Reliability Panel, on advice from NEMMCO and NSPs, determine a standardised method of calculating current ratings of transmission lines and other plant;**
- **deciding whether three phase faults should be included in the definition of a credible contingency event;**

- **removing the apparent conflict between clauses 4.2.3 (b)(2) and 4.2.3(e) and clause S5.1.2.1;**
- **changing the clause requiring code participants to provide voice and data communications equipment so that it only applies to participants with connections above 10MW;**
- **altering the provision requiring all generating units to have governor systems, since it may not be applicable to some forms of generation;**
- **clarifying the questions raised by WPC in relation to clauses 4.2.3(c) and 4.3.2(d); and**
- **addressing all typographical and cross–referencing errors pointed out in the Western Power report.**

While it is in the interests of all participants that the code establish adequate arrangements for power system security, it will also be in their interests that these arrangements are efficient. Opening the supply of ancillary services to competition and using market mechanisms to supply reserve capacity and provide load shedding capabilities are ways to reduce the costs of providing a secure power system. Nevertheless, as the code recognises, NEMMCO will continue to need the ability to intervene in the case of emergencies.

Achieving an appropriate balance between market mechanisms and intervention will not be straight forward. Not the least of which is because the market is evolving from a set of arrangements whereby system security was provided by publicly owned utilities in an environment where market forces were muted. Nevertheless, there appears to be considerable scope to use market mechanisms to deliver some ancillary services and any mismatches between demand and supply. For instance, it could be expected that in order to achieve a balance between capacity and demand, greater use will be made of demand side responses including reducing demand in response to peak load prices and at critical times, making greater use of load shedding contracts and even taking advantage of back up generation capacity located at various sites throughout the network.

However, it cannot be expected that market responses will be sufficient in all circumstances. Clearly it is possible that system security could deteriorate, not in response to customer needs, but as a result of participants in the ESI using market power to reduce the supply of some services. However, in responding to such concerns and in emergency circumstances, it will be important to ensure that administrative interventions do not crowd-out market responses. This can occur by the intervention deadening market signals or by undermining investments. Participants claimed that the rules for intervention need to be closely specified as even the threat or expectation of intervention may significantly reduce the incentive to develop a market response.

Reflecting these range of concerns, in the draft decision, the Commission indicated that in order to accept the access code, it was seeking a commitment from NECA to change the code so that:

- **NEMMCO must report to NECA on the viability of market provision of ancillary services within 1 year of National Electricity Market commencement;**
- **the reserve trading functions in chapters 3 and 4 of the code must end two years after commencement of the National Market;**
- **NECA must conduct an annual review of NEMMCO's use of its powers of direction under clause 4.8.10. The review must be conducted on each anniversary of NEM commencement in respect of the preceding year. The annual review must consider for each occasion on which the power was used in the preceding year, whether the exercise and manner of exercise of the power was appropriate in all the circumstances and in accordance with the code objectives and make any**

recommendations considered appropriate for future exercise of the power. The report of the review is to be completed within 30 days of the end of each relevant year and is to be made available to all market participants.

In the draft decision, the Commission indicated that the Victorian and New South Wales derogations for operating procedures and nomenclature standards are necessary because such arrangements are yet to be developed under the code. The Commission maintains its view that the procedures and standards are acceptable because they provide scope for NEMMCO to revise the arrangements.

The Commission was, however, concerned by the statement in the application that the Network Operating Standards (New South Wales) will prevail over the code in the event of a discrepancy between the two. The Commission commented that this statement is inconsistent with the objective that State operating procedures be replaced by a national approach under the code and is also inconsistent with the derogation which allows NEMMCO to review and update the regional specific operating procedures (clause 9.14.1(b)). The Commission therefore expressed the view that the derogation does not appear to provide scope for the New South Wales standards to prevail over the code in the event of a discrepancy between the two. In this event, the Commission considered that the New South Wales operating procedures derogation is acceptable.

6.2.5 Issues arising from the draft decision

The Commission received several submissions on the requirement that the reserve trader provisions end two years after market commencement.

Pacific Power supports the removal of the reserve trader provisions and considers that this approach is consistent with the removal of many of the market based derogations or interventions by 2000.

CitiPower agrees that the reserve trader provisions should be removed as soon as possible and consider that there should be a review mechanism to determine whether an earlier end date is practical. Eastern Energy also supports the early removal of the reserve trader provisions.

Hazelwood supports the thrust of the Commission’s stance that intervention should be minimised, but recommend the results of the Victorian capacity support program for the 1997/98 summer be considered before a decision is made to remove the reserve trader.

The ACA supports the Commission’s draft decision requiring the phasing out the reserve trader, however it is not convinced that the market will deliver the right outcomes. The ACA states that it believes that network price signals can play an important role in signalling peak capacity and proposes that the issue of security of supply and signals for peak capacity be dealt with in a NECA review.

Solaris agrees with the removal of the reserve trader but would prefer an end date of the end of a financial year.

Ecogen Energy argues against the requirement to end NEMMCO’s reserve trading function two years after market commencement. It argues that without the reserve trading function, there is not enough incentive for market participant to deliver historical levels of reserves because the value of VoLL is too low and will therefore not deliver enough returns for peaking generators to stay in the market.

Ecogen Energy states that if historical levels of reserve are to be maintained, there will need to be capacity payments or the institutionalisation of the reserve trader function or, if the reserve trader function is removed then NEMMCO’s power to intervene to direct market participants to provide reserves should also be removed.

United Energy comments that the removal of the reserve trader function two years after market commencement will create a level of uncertainty regarding supply reliability which is socially and politically unacceptable to governments. United Energy is concerned with the risk associated with the actions that governments may take if they are faced with the possibility of involuntary load shedding. United Energy suggests leaving the reserve trader provisions in the code for longer than two years, but structure the code so as to minimise the likelihood of the reserve trader being needed. It suggests that this could be achieved by requiring the Reliability Panel to set guidelines for the use of the reserve trader that are consistent with the market pricing mechanism.

The Victorian Government is concerned that removing the reserve trader after two years will lead to significant system reliability problems because there may not be the necessary investment to address the capacity problems. Also, the necessary demand side response will not develop unless the risks associated with high spot prices are substantially increased.

The Victorian Government suggests that there should be an immediate review of the NEM design to address interrelated issues such as system reliability and reserve, system security standards, ancillary services, force majeure, the level and definition of VoLL and demand side management. It considers that the reserve trader provisions should not be removed until changes to the market design have been made.

The Victorian Government supports NECA's submission that the period of operation of the reserve trader should be sufficiently long to ensure that there can be experience of at least two summer peak loads.

The South Australian Government argues that there may still be a need for the reserve trader once the market has reached maturity. This is because the current market design may not provide appropriate market mechanisms and significant refinements may be needed before satisfactory market driven solutions. South Australia argues that they will require additional capacity to meet peak demand by about 2001. South Australia considers that they will require a reserve trader for five years, considering the lead time for market driven new investment initiatives. Unlike New South Wales and Victoria, South Australia does not have any mothballed plant that could be recommissioned.

The EUG states that network prices should be used to signal peak capacity requirements and that such issues should be dealt with as part of the NECA pricing review.

Several generators suggested the removal of NEMMCO's power to direct market participants to provide reserves at the same time the reserve trader function is removed. They considered that NEMMCO's power to direct for system security reasons needs to be maintained.

The BCA/EWG would prefer to see a market structure and rules that minimise the need for the reserve trader function.

SMHEA rejects the suggestion that there should be capacity payments or direct intervention. It recommends the removal of the direct intervention provisions at the same time the reserve trader provisions are deleted. It states that the preconditions for the removal of the reserve trader are likely to include an increase in VoLL (to at least $25 000/MWh) and clarification of the co-dispatch of energy and ancillary services under conditions of supply scarcity.

TransGrid comment that several of Western Power's suggestions to change the metering provisions are inappropriate and do not require further review. TransGrid considers that it is inappropriate for the Reliability Panel or NEMMCO to set and impose a method of calculating current ratings of transmission lines and other plant, unless they are accountable for their actions.

TransGrid considers that three phase faults should not be included in the definition of a credible contingency because it will lead to an unnecessary reduction in the power transfer capabilities across interconnectors. TransGrid also considers inappropriate Western Power's recommendation that only participants with connections above 10MW should be required to provide voice and data communications equipment. It argues that NEMMCO will need discretion in this matter, depending on individual circumstances and should not be bound by a strict MW limit.

TransGrid does not support Western Power's suggestion that the provision requiring all generating units to have governor systems may not be applicable to some forms of generation and therefore should be altered. TransGrid state that the provision only applies to scheduled generating units, and a governor is required to enable the generator to follow the dispatch schedule.

6.2.6 Applicant's response to the draft decision

In response to the Commission's concerns that the NEMMCO review of market provision of ancillary services be brought forward, the applicant has revised clause 3.11.1(c) which now states:

> (c) In conjunction with its obligations under clause ~~3.8.9(d)~~ 3.8.1(f), *NEMMCO* must investigate, consult with *Code Participants* in accordance with the *Code consultation procedures* and report to NECA ~~within 2 years of market commencement~~ by 1 March 1999 on the possible development of market-based arrangements for the provision of *ancillary services*, including a short term market in which *Market Participants* which are not parties to *ancillary services agreements* may submit offers for the provision of *regulating capability* or *contingency capacity reserve*.

In response to the Commission's concerns about the reserve trader, the applicant has amended the code by bringing forward the sunset date for reserve contracts. In particular, clause 3.12.1(a) has been amended and states:

> (a) *NEMMCO* may enter into *reserve contracts* in accordance with this clause ~~3.14~~ 3.12 and the relevant guidelines and procedures developed by the *Reliability Panel*, as described in clause 8.8.1, for any period up to ~~the fifth anniversary of market commencement~~ 30 June 2000. *NEMMCO* must not enter into such contracts for the period thereafter.

The applicant has also amended the code by requiring that NECA complete a review of reserve trading by 30 March 2000 (ie prior to the 30 June 2000 sunset date) and that the review must consider a range of matters including: whether NEMMCO (or anyone else) should be involved in reserve trading; whether NEMMCO's role in reserve trading has distorted the spot market; and whether there are alternatives to NEMMCO's current reserve trading role and/or powers.

The applicant has also amended the code by requiring NECA to undertake an annual review of NEMMCO's use of its powers of direction under clause 4.8.10. In particular, clause 4.8.10(e) has been inserted into the code and states that:

> (e) *NECA* must undertake a review of and report on *NEMMCO*'s use of powers granted to *NEMMCO* under clause 4.8.10(a) in each *financial year* as part of NECA's annual report prepared in accordance with clause 8.7.4. The review must consider for each occasion when the powers granted to NEMMCO under clause 4.8.10(a) were exercised::
>
> (1) whether the exercise, and the manner of exercise, of the powers granted to *NEMMCO* under clause 4.8.10(a) was appropriate in the circumstances and was consistent with the *Code objectives*; and
>
> (2) such other matters as NECA considers appropriate,
>
> and may make any recommendations in relation to *NEMMCO*'s future exercise of the power as *NECA* considers appropriate..

6.2.7 Commission's findings

The Commission accepts that the code changes undertaken by the applicant have met the concerns expressed in the Commission's draft decision in relation to: bringing forward a review of the market provision ancillary services; bringing forward the sunset date for reserve trader contracts; requiring NECA to undertake an annual review of NEMMCO's use of its powers of direction.

6.3 Metering

The metering chapter of the access code describes the coverage of the metering requirements; the roles and responsibilities of parties such as the metering provider, the responsible person and NEMMCO; the technical requirements for, and testing of, metering installations; and the auditing, security and processing of metering data. These aspects of the metering chapter of the code are discussed below.

6.3.1 What the applicant says

Coverage of the metering requirements

In the past, consumers have purchased electricity from retailers which were integrated with distribution networks and sometimes with transmission as well. While recent reforms have separated some of these functions, the great majority of consumers will continue to purchase their electricity from retailers — although retail competition will increasingly allow consumers to choose between their retailers.

However, a number of consumers will use the access code to enable them to unbundle their purchases of electricity into wholesale and transport (transmission and distribution) components. Consistent with this vision, the access code's metering requirements have generally been written with a view to the participants in the wholesale market. Nevertheless, in discussions with the Commission, the applicant has indicated that the code's metering requirements also apply to non-local retailers, selling electricity to contestable customers, for the purposes of settling their wholesale market obligations. The applicant also indicated that there is a question surrounding whether contestable customers, who have elected to stay with their local retailer, also need to have metering that complies with chapter 7.

The code has a general principle that all connection points must have a metering installation, however, a subsequent provision in the code only obliges participants in the wholesale market to ensure each of their *market* connection points has a metering installation. These market participants must ensure their metering installations are registered with NEMMCO and they must pay all costs associated with a metering installation.

The metering provider

The metering provider is the person who installs and maintains a metering installation and:

- is responsible for providing and maintaining the metering installation's security controls;
- is required to be registered with NECA and must satisfy the qualifications and standards requirements in schedule 7.4; and
- can be deregistered if they breach the code or behave in an unethical manner.

The applicant (sub. p. 168) states that in order to maintain the integrity of the market, metering providers are required to be reasonably qualified. The applicant submits that the processes and standards involved in registering metering providers are not excessive when compared with the limitations that might exist from having no requirement for metering providers to be licensed.

The applicant also states that the requirement for metering providers to meet knowledge and competency standards rather than complete particular courses, gives individuals more flexibility and increases the possibility of new providers entering the industry. The applicant submits that the categories of registration and the associated competency requirements for metering providers are meaningful as they reflect industry practice.

Any person including a NSP may apply to be registered as a metering provider. Alternatively, a NSP may enter into an agreement for a metering provider to provide metering services. Market participants cannot register as a metering provider for those connection points where they are the energy user. However, the code makes a somewhat unclear exemption for market customers if they are also a NSP and they regard the connected transmission NSP as the local NSP (at the connection points on the transmission network).

Following a request from a market participant, a local NSP must make an offer to provide, install and maintain the metering installation and notify the market participant of the terms and conditions of the offer. If the market participant accepts the offer, the local NSP becomes the person responsible for providing a metering installation (ie the responsible person) and must fulfil the obligations below.

Alternatively, if the market participant declines the NSP's offer, or breaches the agreement with the local NSP, the market participant must arrange for, and enter into an agreement with, another registered metering provider(s) to install and maintain the meter. In this situation, the market participant is the responsible person.

In either case, the code requires the responsible person to provide a metering installation for a particular connection and to:

- ensure their revenue and check metering installations comply with the type, accuracy and design requirements in schedule 7.2;
- ensure the components and testing of each metering installation complies with the requirements of the code;
- arrange for an alarm monitoring feature for certain metering installations, to alert NEMMCO or the responsible person of any failure of the critical components of the metering installation – if the alarm alerts the responsible person, they are required to notify NEMMCO of the failure within a specified period;
- provide NEMMCO with the metering information in schedule 7.5 (for the metering register) for each metering installation;
- ensure that the revenue metering point is located close to the connection point;
- ensure that any instrument transformers required for check metering are located so as to achieve a mathematical correlation with the revenue metering data; and
- ensure that a communication link is installed for each of its metering installations and that it is maintained to the public telecommunications network.

Technical requirements for and testing of metering installations

To ensure the accurate recording of energy data, the metering chapter of the code contains provisions specifying accuracy standards and testing for metering installations and the auditing of metering data. Box 6.2 lists the components of a metering installation that are required by the code.

Box 6.2: Requirements for a metering installation

The code requires that a metering installation:

- has a visible or an equivalently accessible display of metering data;
- be accurate and secure;
- have electronic data transfer facilities between it and the metering database;
- have electronic data recording facilities so data can be collated into trading intervals;
- be capable of separately registering and recording flows in each direction where bi-directional active energy flows occur;
- have an active energy meter and, if required under schedule 7.2, a reactive energy meter, both having an internal or external data logger;
- be capable of communicating from the site of the metering installation to the metering database; and
- have facilities for storing the metering data for at least 35 days.

Chapter 7 of the code also sets out the components (eg current transformers (CT) and voltage transformers (VT), secure and protected wiring from the CT and the VT to the meter, and communication interface equipment) which may be combined to form a metering installation. Features other than those specified may be included, provided a local NSP or market participant seek the agreement of the responsible person.

The applicant (sub. p. 166) argues that the technical specifications for components of a metering installation are necessary for the proper functioning of a low cost, automated, modern metering system and there are public benefits as the code requirements are intended to be technology neutral.

The applicant (sub. pp. 164–165) argues that, given the important role metering plays in the operation of the market (such as determining usage and settling payments for electricity trades), metering installations must conform with recognised standards which participants can rely on. The applicant considers that:

> ...the benefit from the development and operation of the NEM which requires confidence in the metered information far outweighs any perceived detriment to the public from a requirement to meet the metering standards of the code.

The class of, and accuracy requirements for, a metering installation are to be determined according to the annual amount of active energy which passes through the metering point. Check meters are not required to meet the same degree of accuracy as revenue meters, but they must be correlated with the revenue meter and comply with schedule 7.2. If the accuracy of the metering installation does not satisfy the code's requirements, the responsible person must advise NEMMCO of the errors and their possible duration; arrange for the accuracy to be restored within a period to be agreed with NEMMCO; and NEMMCO may make any appropriate corrections to the metering data.

The code requires the responsible person to ensure that purchased metering and associated equipment has been tested to the code's standards and accuracy levels. The responsible person must provide the test results to NEMMCO and any affected code participant that requests the results and must notify affected market participants of the test's outcome.

The code also imposes testing responsibilities on NEMMCO, requiring it to:

- arrange for the testing of any metering installation if so requested by a code participant;
- check the metering register for test results for each metering installation and arrange for audit testing of metering installations;
- negotiate with the responsible person for access to the metering installation for the purpose of testing; and

- make test results available to persons NEMMCO considers have a sufficient interest in the results.

In support of the code's requirements for metering accuracy, inspection and testing, the applicant (sub. p. 167) stated that they 'reflect the collective wisdom and experience of the industry in relation to the technical issues involved.'

Auditing, security and processing of metering data

The code requires NEMMCO to conduct periodic random audits of metering installations to confirm compliance with the code. A code participant may request NEMMCO to conduct an audit to determine if the metering data held in their metering installation is consistent with the data held in the metering database. The code states that if there are discrepancies between such data, code participants must liaise to resolve the discrepancy. The code also states that, in this situation, data in the metering installation is to be taken as prima facie evidence of the metering point energy data. The Commission is uncertain whether this is an apparent inconsistency or whether the provisions are requiring parties to liaise to determine the appropriate energy data, using the data in the metering installation as a benchmark.

The code requires energy data to be collated in trading intervals (half hourly), unless NEMMCO, the local NSP and the market participant agree otherwise. NEMMCO is required to use revenue metering data as the main source of metering data for billing purposes and if check metering data is available, NEMMCO is to use it for validation, substitution and account estimation of revenue metering data. The code requires NEMMCO to develop a data validation process in consultation with code participants.

If there is a discrepancy between the revenue (or check) metering information and the code's requirements, NEMMCO must advise affected code participants of the discrepancy and the responsible person must arrange for the discrepancy to be corrected within two business days, unless exempted by NEMMCO.

The code requires NEMMCO to create, maintain and administer a metering database containing information for each registered metering installation. The market participant, the local NSP and NEMMCO must use their best endeavours to agree to adjust the data in the metering database to allow for physical losses between the metering point and the relevant connection point.

The code specifies which persons can obtain either remote or direct access to metering data from a metering installation, the metering database or the metering register. There is an apparent conflict in the access code regarding the responsibilities for managing access to metering data. On the one hand, NEMMCO must ensure access to metering data from the metering installation is scheduled appropriately to ensure that congestion does not occur. Conversely, the responsible person is required to coordinate the electronic accessibility of each metering installation to prevent congestion.

The code states that the responsible person must ensure the security of the metering installation and associated links, circuits and information storage and processing systems. NEMMCO is required to conduct an audit of the security measures and can exercise its power to override any of the security devices fitted to a metering installation, providing it notifies the responsible person prior to doing so.

The code allows the use of evolving technologies or processes if they

- meet or improve the functional requirements of the metering chapter; or
- facilitate the development of the market; and
- are agreed to by the market participant, the local NSP and NEMMCO.

NEMMCO is required to report on the application of evolving technologies and processes and the extent to which the metering chapter needs to be amended to accommodate these or the development of the market.

In supporting the code's metering requirements, the applicant (sub. p. 105) argued that the code's prescriptiveness for the responsibilities and obligations of code participants helps to reduce ambiguity and makes the requirements for entry clearer and less risky to possible new entrants. However, the applicant (sub. p.107) acknowledges that the metering chapter of the code

> ...is subject to a review to assess whether arrangements can be less prescriptive, more flexible and allow market driven responses.

Derogations

Jurisdictions have derogated from some of the code's metering provisions (see Table 6.2).

6.3.2 The consultant's views

The Western Power review concluded that the metering requirements of the code do not act as a barrier to entry to market participants establishing new connections above 1 GWh per annum, nor to metering providers. Moreover, Western Power stated that the metering requirements will have virtually no impact on new network providers and new network investment because the cost of new metering is only a small part of the cost of a new connection.

Table 6.2 Metering Derogations

Jurisdiction	Expiry date	Details
Victoria (1)	29/3/1999	Metering installations are taken to be registered with NEMMCO if they are registered with VPX at market commencement and details given to NEMMCO.
	29/3/2000	Metering installations are taken to comply with the code's requirements for components and design standards.
	29/3/2003	Minimum level of accuracy requirements different to the code.
	not specified	Responsible person given 6 months from market commencement to demonstrate that metering installations meet the derogated accuracy requirements.
	29/9/1998	Holders of distribution or transmission licences at market commencement are taken to be registered metering providers.
	not specified	It is taken as agreed that alternate technologies or processes (specified in the Wholesale Metering Code) for calculating energy consumption by non-franchise customers can be used.
New South Wales	29/3/1999	Metering installations are taken to be registered with NEMMCO if they are registered with TransGrid at the code commencement date and details given to NEMMCO.
	not specified	TransGrid may extend the period by which the metering installation must comply with chapter 7 of the code (2).
ACT South Australia (3)	not specified	If requested, the Local NSP is obliged to make an offer for the upgrading of an existing metering installation.
	29/3/1993	Minimum level of accuracy requirements (similar to Victoria).
	not specified	Various derogations on meter types and components.
	not specified	NECA must verify compliance of NSPs with registration requirements within 2 years of code commencement.

(1) Victoria's derogations apply to metering installations in use at market commencement, which comply with Victoria's Wholesale Metering Code.

(2) NSW's metering installations must comply with chapter 7 of the code at the code start date, unless the responsible person has been granted an extension by TransGrid.

(3) These States' derogations are for existing metering installations where the participant opts to join the wholesale market within the first 5 years of the market's operation.

Western Power state that the metering provisions encourage competition in installing and maintaining meters by allowing the market participant to choose whether a local NSP or some other metering provider provides these services. They also argue that the responsibilities of metering providers are not so burdensome to act as an entry barrier. Indeed, Western Power believes that these responsibilities are not defined clearly enough, which may lead to unnecessary metering disputes and the need to remedy substandard metering installations following the possible default of the metering provider.

One of the most significant concerns that Western Power raised about the metering chapter of the code is that it does not address the needs of smaller customers. The cost of metering will continue to discourage low end users (down to households) from entering the market until low cost communication is available. Western Power suggest that market customers (retailers) with connections of less than 1 GWh should be exempt from some of the code's requirements for metering installation components. They also argue that the requirements for the responsible person are a burden for low voltage market customers.

Western Power argue that the alternative of using standard load profiles for small users has disadvantages because it precludes smaller users from taking advantage of demand side initiatives and it introduces extra risk because of the wide variation in domestic usage. Load profiling may also discourage the development of low cost communication systems and low cost meter offerings.

Another concern raised by Western Power is that the code may both advantage and disadvantage NSPs. The requirement for participants to request a quotation from the NSP for new metering installations gives NSPs an advantage over other metering providers. However, NSPs may be disadvantaged if they are obliged to accept responsibility for an existing installation that is below standard. Persons building new installations may be disadvantaged by the ability of existing metering installations to be exempt from the code's metering requirements.

Western Power expressed concern that competition will encourage independent metering providers with no commercial interest in meter accuracy to offer low cost, low quality installations. They argue that it is in the long term interests of all market participants if the code ensures that the accuracy of metering installations is related to the value of the commodity traded.

The Western Power review also raised other concerns that:

- the code sets a low standard for metering, which is contrary to market participants' longer term interests;
- the responsible person's degree of self regulation conflicts with their commercial interests in the metered data and is often contrary to the interests of a NSP or other market participants;
- the responsible person's role in ensuring the security of the metering installation may encourage malpractices if they are also a market participant;
- NEMMCO's, and its agents', right to inspect metering installations is too restricted;
- parties, other than NEMMCO and its agents, who have a commercial interest in the metered data should be allowed to inspect and witness testing;
- NEMMCO should have unrestrained access to the metering installation for the purpose of conducting random audits;
- NECA's role of registering metering providers is inconsistent with its main function and expertise – it would be more appropriate for NEMMCO to perform the function, given

they are responsible for registering metering installations, approving metering security devices and sealing and issuing exemptions for compliance with metering standards;

- agreements for providing metering installations should include a completion date;
- it is unclear whether the termination of an agreement under clause 7.2.3 includes a breach of contract by the market participant during or after the provision of a metering installation by the NSP. The clause does not allow for the situation in which the NSP breaches the contract;
- the market participant should, at their own cost, allow the NSP to locate check metering on their premises if the market participant opts for a metering provider, rather than a local NSP, to provide metering services;
- there is no provision for the market participant to choose a different metering provider for ongoing metering support;
- series metering should be used by medium and large market participants to improve accuracy. In this case, there is no need for any other form of metering, however, market customers above 10 GWh may decide to install check metering;
- the connection agreement should specify the method for determining losses between the metering point and the connection point;
- it is unrealistic that there will be a mathematical correlation between check and revenue metering data if the meters have different accuracy levels;
- the code should specify the requirements and certification of data collection agencies and the technical and administrative requirements for agency databases;
- clause 7.6.1(d) implies that NEMMCO is responsible for testing metering installations, contrary to other clauses which assign this responsibility to the responsible person;
- the local retailer responsible for distributing power should have unrestrained access to inspect the metering installation of first tier customers because the National Standards Commission Weights and Measures Act requires that both the seller and the buyer have access to local meter readings; and
- there are several clauses that are contradictory or unclear; errors and omissions in the schedules; and minor textual errors.

With respect to Victoria's metering derogations, Western Power argues that there are no doubt good reasons for derogations concerning differences in accuracy, conformance with code quality and check metering during the transition period, arising from different metering regimes. They state, however, that it is difficult to see the need for other provisions to differ, such as the registration of metering installations and metering providers and arrangements for submultiples of metering periods. Western Power adds that the six months grace given to responsible persons in Victoria to demonstrate the accuracy of metering installations seems unnecessary and may afford entry advantages in Victoria compared to other States.

6.3.3 What the participants say

One of the main concerns raised in submissions was that the cost of metering will act as a barrier to small customers seeking entry to the market.

The joint submission from the Victorian Distribution Businesses (sub. p. 23) observes that the metering provisions of the access code have been drafted for the requirements of relatively large participants and the access code will need to evolve to accommodate the needs of smaller customers.

The EUG (sub. p. 87) state that metering can be a reasonably costly adjunct to participation in the NEM, although there appears to be very little reliable information available about the likely costs of the access code's proposals. The EUG point to the example of unexpected higher metering costs in the UK pool and suggest that the applicant be required to provide the ACCC with indicative metering costs.

The EUG (sub. p. 88) accepts that while the cost of metering will be relatively less for larger users, it could still be significant because of the requirement for large users to have separate metering at each site. The EUG notes that while the applicant expects the NEM to be mainly made up of larger users, an increasing number of customers will become contestable and for smaller users the costs of metering may reduce their ability to participate in the NEM. The EUG has suggested that there should be an examination of the feasibility of using deemed load profiles as a substitute for metering in certain cases.

TransGrid (sub. p. 8) believes that the metering requirements in the access code for those entering the wholesale market would be a small component of the value of traded energy, however, the issue they say is for the retail market which involves smaller customers. TransGrid states that there are views that load profiling should be used in the retail market, however, they note that load profiling introduces significant risks to both the host retailer and the retailer of choice, and that these need to be weighed up against the advantages.

Delta Electricity (supplementary sub. p. 4) submits that practicality requires load profiling to be permitted in the short term, but adds that pressure should be maintained for improved metering technology.

The National Farmers' Federation (NFF) also raise concerns about the cost of metering. They submit (sub. p. 3) that:

> ... the code requires all metering installations to be capable of providing electronic transfer of data to the metering database. This is likely to add substantial fixed cost to the metering installation, and will force customers who wish to have a choice of electricity supplier to install new metering in their premises. NFF is concerned that such a requirement is likely to limit smaller customers from fully participating in the market.

Australian Paper (sub. p. 2) believes that operating in the NEM requires expensive metering and that at the domestic end of the market, the costs of such metering will outweigh the benefits of deregulation. Instead Australia Paper calls on the development of a method of system control which does not require such extensive metering costs.

The Tasmanian Government (sub. p. 9) believes the metering requirements will impose a significant compliance cost for participants in a system such as in Tasmania where currently revenue metering occurs only at the end user customer premises. It adds that this compliance cost would apply to all market participants, and is likely to become a more significant issue as the contestability thresholds are reduced.

Integral (sub. p. 7) submitted that many of the meters currently in service within their supply area do not meet the password requirements of the code and some allowance should be made for these meters to remain. They argue that it would be an unnecessary expense to customers to replace single level of password meters with meters that comply with the code.

Another area of concern raised in submissions relates to the requirements of metering providers and metering agents and whether metering provision and data collection should be contestable.

TransGrid (sub. p. 8) supports contestability in both metering provision (ie installing of meters) and metering agencies (ie the acquisition and initial processing of data) and argues that it should be a requirement in the code. TransGrid argue that contestability is necessary to drive the innovation and cost reductions in metering, which are necessary for smaller customers to participate in the market. TransGrid advised that New South Wales is developing procedures to allow contestability in both metering provision and the collection of metering energy data.

The New South Wales Electricity Taskforce (sub. pp. 1–2) is supportive of changes to the code which facilitate contestability among metering agents. The Taskforce states that the access code needs to clarify whether the retailer of choice or NEMMCO is responsible for determining which metering agent serves the retail customer. The Taskforce believes the retailer of choice is best placed to be accountable for metering provision and data collection. They base this belief on two principles: risk management and the separation of contestable and non–contestable functions.

The Taskforce points out that, in relation to risk management, some risk of mal-operation of metering and data collection systems will continue and that this risk should be deployed to the market participant, rather than being spread across the market generally, or being deployed only to a party whose involvement is based principally on their technical accreditation. For this reason the Taskforce suggests the access code should clarify that the retailer of choice is accountable to NEMMCO for correct operation of metering and data collection. This accountability structure will then be completed by the retailer of choice being able to choose (and contract with) the supplier of contestable services (ie metering and data collection).

In relation to the separation of contestable and non–contestable functions, the Taskforce submits that metering and data collection is not a centralised function. They point out that contestable and non–contestable functions are separated throughout the market and there should be no exception for the functions of NEMMCO.

The EUG (sub. p. 88) notes that the access code proposal to licence metering providers and to subject them to a series of procedures for approval will restrict customers in their choice of metering provider and could increase the cost involved. The EUG suggests it may be preferable to provide for voluntary registration or accreditation with NECA and rely on the metering standards for compliance. In contrast, Integral Energy has submitted that the requirements for metering providers in Schedule 7.4 lack clarity.

The Victorian Distribution Businesses (sub. p. 23) have questioned the merits of including separate metering providers in an already complicated arena where customers, retailers and the NSPs will interface. They also submit that metering errors ultimately pose a risk to the local distributor, not the independent metering provider and that this and other issues (such as the ownership of meters) need to be considered more closely before a contestable metering regime is adopted.

The Victorian Distribution Businesses (sub. pp. 23–24) suggest that accuracy could be compromised by allowing NEMMCO to use agencies to collect metering information and by enabling agency databases to form part of the metering database. They note that agencies are not bound by the code unless they are local NSPs, market customers, market generators, or metering providers. This could result in a situation where critical metering information is controlled by persons not bound directly by the code. This poses the unacceptable risk that accuracy could be compromised if data held in the agency databases are not subject to rigorous requirements for accuracy through compliance with the code. The submission contends that the performance standards and obligations of the agency databases to be used by NEMMCO should be prescribed by the code. Agencies should be bound by the code in relation to all relevant matters, including dispute resolution, when there are disagreements about the metered data.

Integral (sub. p. 7) submitted that the code will need to define the requirements of metering agents as it does for metering providers.

Other issues raised in submissions included the process for data substitution, the length of the trading interval and the code's allowance of the use of certain evolving technologies or processes.

The Victorian Distribution Businesses (sub. p. 24) also submit that accurate metering data forms a critical link in the commercial transactions of code participants. It is inevitable that circumstances will arise where accurate metering data is unavailable due to meter failure, or other causes, and NEMMCO must develop data substitution processes in consultation with code participants for application under clause 7.9.4(d) in such circumstances.

With respect to data validation and substitution, EnergyAustralia (sub. p. 6) submits that where metering data cannot be used for the purposes of settlement, the data substitution must be undertaken in consultation with all affected code participants, not just with the market participant and the local NSP.

In relation to periodic energy metering, the Victorian Distribution Businesses (sub. p. 24) state that all meters installed in Victoria for the purposes of pool participation have 15 minute recording intervals which is a sub multiple of the trading interval. They suggest that the current drafting of clause 7.9.3 represents an unacceptable risk that existing metering arrangements may need modification if NEMMCO or the market participant do not agree to energy data being recorded in such a sub multiple. They also note that the derogation under clause 9.9.9 of the code may not be required if the code directly accommodated the 15 minute interval.

EnergyAustralia (sub. pp. 6–7) submits that it is concerned about what a market participant may propose as falling under 'evolving technologies or processes'. It requests that such technologies and processes should only be implemented after broad consultation has been undertaken. A restricted consultation process in some circumstances may well prove to be appropriate but EnergyAustralia does not generally support this type of approach.

6.3.4 The Commission's considerations

The Commission believes that metering is essential for the effective operation of the NEM, given its role in managing usage and determining financial settlements (ensuring generators are paid for the quantity they produce and customers pay for the quantity they purchase). The measurement and settlements functions of metering in the NEM are no different to the important role metering has in other areas, for example in taxis, at petrol stations and the electronic recording devices in supermarkets.

Despite the public benefits that derive from an accurate and reliable metering system, a large number of participants – transmitters, distributors and users – and the Commission's consultant have raised concerns about the cost of the code's metering requirements, including the provision of the meter, the communications link and data analysis for determining settlements.

However, many of these concerns have not been raised in the context of the access code and the wholesale market (ie large users), but rather the retail market and smaller users. Indeed, the Commission has been advised by Western Power that for medium to larger users the cost of metering will be small relative to the overall cost of connection. The Commission maintains the concern it expressed in its draft decision that small contestable customers (less than 1 GWh) will not receive the benefits of competition in the retail market because the lower energy prices offered by non-local retailers will be outweighed by the additional metering costs these retailers will face.

It is likely that small consumers would remain with their local retailer, rather than transfer to a non-local retailer who would be required to install a half hourly meter that complies with the code. In the draft decision, the Commission stated that the current metering requirements in the access code are deficient in relation to the retail market because they will discourage retail competition until there are improvements in technology which reduce metering costs. As Table 6.3 shows, franchise thresholds are falling. New South Wales and Victorian customers consuming more than 750MWh annually are now able to unbundle their electricity purchases. Metering is now an important issue for these customers, assuming that 1 GWh per annum is taken as the lower cut off point beneath which any cost savings from transferring to a non-local retailer are outweighed by the additional metering costs. The concerns over metering arrangements for retail competition will become an even greater issue from July 1998 when customers between 160MWh and 750MWh become contestable.

Table 6.3 Contestability Thresholds in New South Wales and Victoria

Jurisdiction	Site threshold	Eligibility date
New South Wales	>40GWh pa	1 October 1996
	>4GWh pa	1 April 1997
	>750MWh pa	1 July 1997
	>160MWh pa	1 July 1998
	>25MWh pa	1 January 2001
	>10MWh pa	1 July 2001
	zero threshold	1 March 2002
Victoria	>5 GWh pa	December 1994
	>1 GWh pa	July 1995
	>750MWh pa	July 1996
	>160MWh pa	July 1998
	zero threshold	January 2001
Queensland	>40 GWh pa	29 March 1998
	>4 GWh pa	1 October 1998
	>200MWh pa	1 July 1999
	zero threshold	1 January 2001
ACT	>20 GWh pa	21 December 1997
	>4 GWh pa	1 March 1998
	>750 MWh pa	3 May 1998
	>160 MWh pa	28 June 1998

To the extent that the metering provisions are not a problem for the access code, which large users will use to unbundle their electricity and transportation purchases, it is acceptable to the Commission. However, the Commission stated in its draft decision that:

> **The National Electricity Market access code would be improved by an investigation of the practical alternatives for smaller customers to ensure that they are not precluded from participating in the NEM.**

The Commission suggested that any new metering arrangements for the retail market should be flexible rather than the prescriptive single metering standard necessary for the wholesale market. That is, customers should be able to benefit from retail competition while not placing open ended risks on the retailer. For example load profiling could be allowed in situations where electricity consumers are unable to radically change their usage patterns, thereby placing little risk on the host retailer. This would occur in circumstances in which electricity is a derived demand, such as telecommunications, where the demand for such services is unlikely to be influenced by the price of electricity.

The Commission considers that the provisions in the access code which introduce contestability in supplying and installing meters will provide a catalyst for technical innovation and will drive down the cost of metering. This view is supported by several participants, although the Commission acknowledges that the Victorian Distribution Businesses have concerns about contestability of metering provision. The Commission also considers that that metering costs will be reduced by introducing competition to metering agents (persons responsible for data collection). In the draft decision the Commission indicated that before accepting the access code it was seeking a commitment from NECA to amend the code:

> **to allow for the development of competition among metering agents (persons responsible for data collection).**

With respect to metering agents, the Commission also accepted Western Power's and participants' concerns that the code does not clearly define their role and responsibilities. The Commission accepted the Victorian Distribution Businesses' concern that metering information could be controlled by metering agents who are not bound by the code (ie those agents that are not local NSPs, market participants or metering providers). The Commission stated that this poses a risk to the accuracy of metering data which is contrary to the interests of network service providers, network users and the public. In the draft decision the Commission also indicated that the code would be improved by specifying

> **the role and qualifications of metering agents; the requirements for agency databases; and that metering agents be required to comply with the code's standards and obligations.**

In the draft decision, the Commission also indicated that before accepting the access code, it was seeking a commitment from NECA to:

> **refer the issues raised by participants and Western Power's review of the code's metering arrangements to the code change processes. Western Power's comments include the concerns that:**
>
> - **the code sets a low standard for metering, which is contrary to market participants' longer term interests;**
> - **the responsible person's degree of self regulation conflicts with their commercial interests in the metered data and is often contrary to the interests of a NSP or other market participants;**
> - **the responsible person's role in ensuring the security of the metering installation may encourage malpractices if they are also a market participant;**
> - **the market participant should, at their own cost, allow the NSP to locate check metering on their premises if the market participant opts for a metering provider, rather than a local NSP, to provide metering services;**
> - **there is no provision for the market participant to choose a different metering provider for ongoing metering support; and**
> - **there are several clauses that are contradictory or unclear; errors and omissions in the schedules; and minor textual errors.**

As indicated in the draft decision, the Commission considers that since Western Power's suggestion are of a technical nature, the industry, rather than the Commission, is best placed to reconsider their merits

In the draft decision, the Commission indicated that the jurisdiction's metering derogations are generally acceptable since they facilitate an orderly transition to the NEM's metering arrangements. In assessing the jurisdiction's metering derogations, the Commission took into account Western Power's and participants' views. The Commission also acknowledged that requiring market participants to comply with chapter 7 of the code from market commencement would require some metering installations currently in place to be upgraded or replaced rather than allowing for a phasing in of new metering equipment. This would place a cost burden on existing market participants.

The Commission also indicated that the time limits for most of the derogations are reasonable. However, the Commission expressed concern with New South Wales' derogation which allows TransGrid to grant an extension to the time period in which metering installations in New South Wales have to comply with chapter 7 of the code. Whilst appreciating the need for some discretion, the Commission stated that this derogation must not continue beyond a reasonable transition period. **Accordingly, the Commission stated in its draft decision that the New South Wales derogation must be altered so that the period of the extension granted by TransGrid does not extend beyond five years of market commencement.**

The Commission also required that the code be amended so that the South Australian and ACT derogations regarding meter types, components and alarms contain a transitional period, as it is currently not specified.

In the draft decision, the Commission indicated it would accept South Australia's and the ACT's derogation that requires a local NSP to make an offer to upgrade an existing metering installation if so requested. After taking into account the comments made by Western Power, the Commission recommended that this requirement also be imposed on other metering providers and should also apply in Victoria and New South Wales.

The Commission also suggested that Victoria and New South Wales consider including a provision, as in the South Australian and ACT derogation, that requires NECA to verify whether NSPs comply with registration requirements within 2 years of code commencement in order for these NSPs to maintain their registration granted at code commencement.

The Commission indicated in its draft decision that it would accept the Victorian derogation which allows responsible persons in Victoria an extra six months grace to demonstrate the accuracy of metering installations since the entry advantages accruing to them as a result of this derogation would appear to be minor.

6.3.5 Issues arising from the draft decision

In a joint submission in response to the Commission's draft decision, the New South Wales DNSPs state their support for competition in the provision of metering data agent services. However they express concern that there is no obligation on the metering data agent to provide the NSP with the metering data required for network billing purposes. They suggest that the code should be amended to require NEMMCO to establish a process to ensure the timely delivery of data suitable for network billing. They also suggest that NECA should, as part of its review of network pricing, develop a standard data format for determining network usage.

EnergyAustralia argue that the data provided to NEMMCO by meter data agencies is unsuitable for network pricing because it will be grossed up by distribution loss factors. It states that DNSPs will need to obtain data separately from the meter data agencies. It considers that the current arrangements could prevent contestable customers from changing retailers because of unsatisfactory arrangements for the settlement of network charges. EnergyAustralia suggests that the ACCC should require the code to place an obligation on meter providers to ensure an uninterrupted stream of data for market and network billing purposes and to ensure that the property of the original meter service provider is safeguarded. At the pre-decision conference, EnergyAustralia argued that while they would like to see contestability in the provision of metering services, the code needs to be amended to ensure a continuity of data is achieved when metering facilities are changed.

In a joint submission, the New South Wales DNSPs argue that the code should provide for the metering provider to consult with the local NSP before altering a metering installation. They argue that this is necessary as the NSP requires this information to review the structure of network tariffs for the customer and advise them accordingly.

The EUG supports the suggestion that the code should include practical alternatives for smaller customers and recommends that there be effective co-ordination between jurisdictions on this issue.

TransGrid supports the inclusion of metering requirements for smaller customers in the code, however they argue that the necessary amendments must be made before 1 July 1998, to give metering providers adequate time to order new equipment. It also draws the Commission's attention to work undertaken by the Office of the Regulator General, Victoria (ORG) to devise a satisfactory solution to the problem of smaller tranche customers.

CitiPower argues that the code must state that host distribution businesses should not bear any additional costs as a result of new metering requirements for smaller customers.

Solaris argues that the Commission's suggestion to include new metering requirements for smaller contestable customers seems to raise as many questions as it answers. Solaris argues that the real issue is whether the cost of alternative methods of market settlement is less expensive. Solaris also believes that NECA should conduct a review of both metering technology and market settlement options to allow more cost reflective options to be identified before any changes are made to the code.

United Energy argued that deemed load profiling should not be considered as a solution if the cost of metering for smaller customers is excessive. It argued that deemed load profiling has the potential to deliver an extremely inefficient outcome by not allowing true pricing signals at times of system stress.

Eastern Energy argued that the requirements for customers below the 160MWh/ year tranche will be dependent on technology and may require further amendments post-July 1998.

Australian Paper stated that the ACCC should specifically mandate ways that are acceptable as alternatives to overcoming the high cost of metering as required by the code.

6.3.6 Applicant's response to the draft decision

NECA has accepted the Commission's position that practical alternatives for smaller customers need to be investigated. Indeed, NECA indicated that it is a member of the NEM metering and retail settlements steering committee which is already investigating practical alternatives to metering for smaller customers. NECA also stated that it will ensure that the committee is "aware of the Commission's other concerns in relation to competition among metering agents, the need to specify the role and qualifications of metering agents, the requirements of agency data bases, and compliance of metering agents with the Code's standards and obligations".

6.3.7 Commission's findings

The Commission finds acceptable the applicant's response that it will raise the Commission's concerns about the code's metering arrangements within the context of the NEM metering and retail settlements steering committee. While the Commission is satisfied with the applicant's commitment to raise Commission's metering concerns, this is no guarantee that the issues will be resolved.

In general, the major concern of the Commission and participants in this assessment process have been related to the cost of metering and identifying and implementing practical alternatives for metering smaller customers. To a large extent these concerns have not been raised in the context of the access code and the wholesale market (ie large users), but rather the retail market and smaller users. Effective resolution of these matters will require the establishment of seamless metering arrangements between the code (which largely deals with the single wholesale market in the NEM) and the regulation of retail competition in each of the participating jurisdictions.

The Commission believes there is a danger that, if the jurisdictions and the NEM administrators are unable to address industry and public concerns, the benefits of retail competition may not be passed through to smaller customers.

7. Disputes and code enforcement

The approach chosen for the access code and undertakings reflects a negotiation model whereby the code and undertakings provide general guidelines which are flexible enough to cope with a broad range of circumstances over a long period of time. The detail of the arrangements will be determined on a case-by-case basis through negotiated connection agreements.

Consequently, the access code generally relies upon procedures and objectives to implement its framework for negotiating access terms and conditions. Although technical standards are closely defined, many other outcomes are dependent on the parties following the processes available in the code. The advantage of this approach is that the access procedures can be flexibly adapted across a variety of situations to suit the particular circumstances of the negotiating parties.

However, this may lead to disputes in that even where parties abide by the code processes and negotiate in good faith they may still arrive at different judgements and interpretations. The effect of disputes is that they stop or retard the progress of negotiations, add to the cost of using the access procedures and can jeopardise the rights of access established under Part IIIA of the Trade Practices Act.

Hence, when a dispute or code breach arises, effective mechanisms are needed to resolve the problem promptly and effectively so that the relationship and dealings between the parties can advance. It is also in the interests of third parties and the public interest in general that problems with either the code or access and competition issues which are identified in a dispute or breach are rectified in a timely and cost efficient manner.

This chapter commences with an overview of the code's dispute resolution and enforcement procedures (7.1) and the issues the Commission considers are relevant in their assessment (7.2). The Commission then separately analyses the dispute resolution (7.3) and enforcement procedures (7.4).

7.1 Overview of dispute resolution and enforcement procedures

Chapter 8 of the code deals with the responsibilities both NECA and code participants have for dispute management, code enforcement and code changes. All of these areas may affect the operation of the connection, use of system, augmentation and pricing aspects of the access code. The Commission understands that the disputes function is intended to deal with disagreements between:

- a participant and its NSP over connection or augmentation procedures, requirements or performance ;
- a participant and its NSP or NEMMCO over tests, inspections or commissioning;
- a participant and its NSP or NEMMCO over disconnection or reconnection; and
- participants over compliance with the code, particularly the issue of rights of entry to inspect a competitor's operations.

With regard to breaches of the code, the National Electricity Law requires all participants to be registered under the access code which in turn binds all participants. Compliance with the code will be monitored and enforced primarily by NECA and breaches of the code are to be examined and decided by the National Electricity Tribunal upon application by NECA. In addition the Commission can seek Federal Court orders to ensure compliance with access undertakings.

7.2 Issues for the Commission

In any regime, it is likely that disputes will arise. In a changed environment such as the NEM, it is inevitable that disagreements, disputes and code breaches will occur over the interpretation and implementation of the code.

Disputes and breaches are likely to affect the interests of users and providers because:

- the need for agreement and negotiation on many (often complex and technical) issues increases the probability of disagreements;
- the access code represents a new regime which is likely to have transitional problems at both the systemic and individual level, especially with new entry;
- negotiating with monopoly providers has inherent problems for users with unequal bargaining power; and
- responses to disputes and code breaches can potentially affect, if not harm, the interests of third party providers and users of the network, particularly if it results in disconnection (for a discussion of disconnection, see section 4.5 of this decision).

For these reasons, and in light of its statutory criteria in s.44ZZAA of the Trade Practices Act, the Commission needs to be sure of the adequacy of the code dispute resolution processes and enforcement mechanisms in terms of serving:

- the interests of NSPs and users in having a fair, responsive, affordable and well-defined means of resolving disputes or adjudicating code breaches on the basis of an impartial assessment of the participants' rights, obligations and claims; and
- the public interest in establishing and maintaining confidence in the administration and implementation of the code not just for the benefit of code participants but all people affected by the use of electricity.

Both the dispute management and code breach processes need to establish fair and efficient processes conducive to fair and workable outcomes which reinforce the objectives of the code, respect the interests of involved parties and take account of the wider interests of network providers and users, including the public interest. It is most likely that this can be best achieved by ensuring these processes reflect established principles of natural justice and effective dispute management (see Box 7.1).

The Commission will examine how adequately the arrangements provide for the explicit expression of natural justice and effective management principles in both the dispute resolution and the enforcement objectives and procedures.

Box 7.1: Principles of dispute management and natural justice

In order for the code to operate efficiently, there needs to be an effective mechanism for resolving disputes. Accordingly, the Commission considers the following principles to be relevant to its assessment of the dispute resolution provisions contained in the code.

Dispute Management

The Commonwealth's Justice Statement recognised the importance of dispute resolution mechanisms which enable people to resolve disputes by simple and accessible means before pursuing the formal avenue of litigation. Although there are a range of possible dispute resolution models (eg arbitration and mediation), an effective dispute resolution process will usually involve:

- accessible, cost-effective procedures emphasising early resolution of disputes and time limits within which each process must be utilised;
- transition from a non-interventionist to an interventionist process;
- a defined decision at the end of each process, which is binding on the parties, without foregoing legitimate avenues of appeal;
- flexibility to meet the needs of parties but sufficient certainty and completeness so that rights and obligations are protected and the outcome is enforceable; and
- accountability through examination of the criteria used to assess and resolve disputes.

Natural Justice Principles

Natural justice, or procedural fairness, is a well established requirement for administrative decision-making. Its main features are:

- the *hearing rule*, which requires the decision-maker to give the person whose interests will be affected by the decision, an opportunity to be heard; and
- the *bias rule*, which requires the decision-maker to be disinterested or unbiased in the matter to be decided.

Although the required procedures vary depending on the individual circumstances of the case, procedural fairness generally involves:

- prior notification to affected persons that a decision will be made;
- the right of people to be actively involved in decisions affecting their interests including the opportunity to present their case and respond to claims or allegations;
- uniform and impartial application of rights, duties and procedures;
- an unbiased decision-maker subject to the need for appropriate technical industry expertise; and
- the right of affected persons to know the reasons for the decision, and the public interest in publishing decisions subject to legitimate claims of confidentiality.

Sources: Attorney-General's Department, *Justice Statement* (May 1995) chapter 2; David, 'Designing a Dispute Resolution Process' (1994) 1 *Commercial Dispute Resolution Journal* 26–38; Spencer, 'Uncertainty and Incompleteness in Dispute Resolution Clauses' (1995) 2 *Commercial Dispute Resolution Journal* 23–40. See also *Administrative Decisions (Judicial Review) Act 1976* (Cth); Allars, *Introduction to Australian Administrative Law* (Butterworths, Sydney, 1990); Sykes et al, *General Principles of Administrative Law* (Butterworths, Sydney, 3rd ed 1989); Aronson & Dyer, *Judicial Review of Administrative Action* (LBC Information Services, New South Wales, 1996).

7.3 Disputes

7.3.1 What the applicant says

The applicant states (sub, pp. 62, 257–260) that disputes relating to connection applications, connection agreements or other access matters will be resolved in the first instance through the code's dispute management procedures.

The code states that the dispute management procedures in chapter 8 (depicted in Figure 7.1) apply to code participants including NECA. These procedures must be in accordance with criteria determined by NECA as well as those set out in the code. For instance, procedures must:

- be guided by the market and code objectives in the code;
- be simple, quick and inexpensive;
- preserve or enhance the relationship between the parties to the dispute;
- take account of the skills and knowledge that are required for the relevant procedure;
- observe the rules of natural justice; and
- emphasise avoiding conflict and encouraging dispute resolution without formal legal representation or reliance on legal procedures.

Despite these formal requirements, the code provides additional flexibility by allowing network providers and users to agree on alternative arrangements within the terms and conditions of their individual connection agreements.

In general the code encourages the parties to resolve their disputes between themselves before invoking more formal, resource-intensive measures. Failing resolution through internal mechanisms, disputes will be referred to the Dispute Resolution Adviser (appointed by NECA) who may either mediate the dispute or refer it to a Dispute Resolution Panel set up by the Adviser. However, if these procedures do not settle the dispute, code participants are free to pursue other options to resolve disputes between them.

While needing to possess expertise in both dispute resolution and the electricity industry, the Adviser and Panel members cannot be code participants and must not have any interests which could conflict with an impartial resolution of the dispute. A Dispute Resolution Panel's procedures can involve:

- exchange of submissions, documents and information;
- consultation with all parties affected by the dispute; and
- adequate opportunity for those parties to present their case.

Dispute panel decisions are recorded and both the Adviser and Panel are obliged to produce a summary of their determinations or mediations, without identifying parties and subject to the code's confidentiality provisions. NECA must publish or make available these summaries to all code participants on a regular basis.

In particular, the code states that the dispute resolution regime applies to any dispute between any code participants (including NECA) and covers such areas as:

- the application or interpretation of the code;
- contracts adopting the code procedures;
- failure to reach agreement on a matter where the code requires agreement;
- a dispute concerning certain augmentation of a network; or
- the payment of moneys under or concerning any obligation under the code.

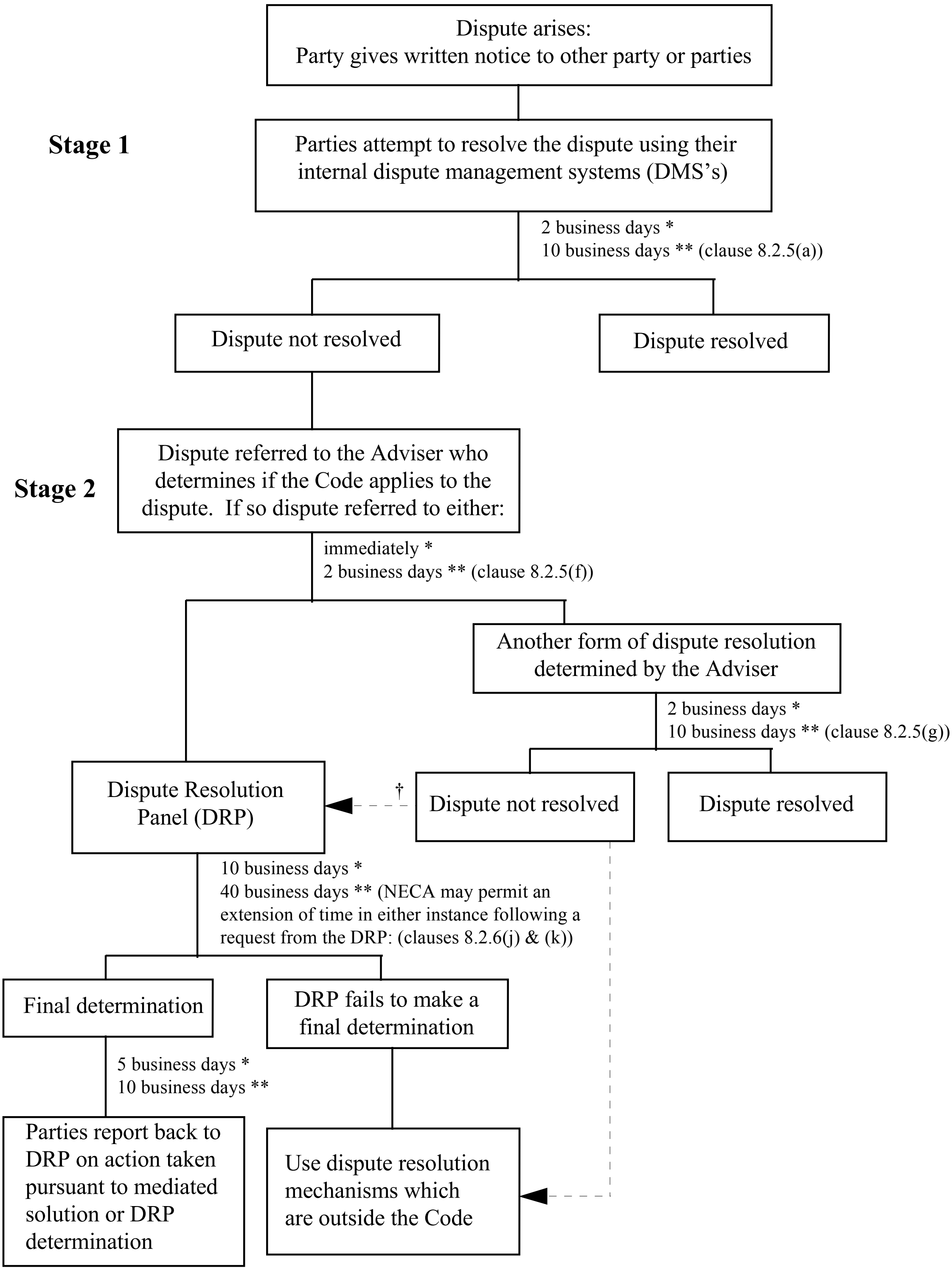
Individual clauses of the code state that certain disputes will be resolved through either the chapter 8 provisions or some other regulatory mechanism. For example, the ACCC is nominated to arbitrate disputes concerning generator transmission use of system charges and transmission network capital contributions. The Inter Regional Planning Committee will settle disputes over parameter settings. Jurisdictional Regulators will settle disputes concerning embedded generators' distribution use of system charges and distribution capital contributions.

In addition to its decisions on code breaches (see below), the National Electricity Tribunal also can re-examine NECA's and NEMMCO's 'reviewable decisions'.[21]

The applicant indicates (sub, pp. 175, 183, 196, 264–5, 290ff) that, at least for the transition period (till 1999/2000), disputes over network access and connection will remain with the jurisdictional regulators by dint of the almost identical chapter 9 derogations (see Table 7.1). Local laws and procedures will apply instead of the code dispute provisions.

- [21] The access code defines that the following are reviewable decisions:
- a NECA decision to exempt a code participant from providing an access undertaking;
- a NEMMCO determination that an augmentation is or is not justified;
- a NEMMCO determination whether or not a proposal to establish an interconnector is justified;
- NECA approval of network pricing software; and
- a NECA decision to impose additional requirements, procedures or standards on a participant.

Figure 7.1: Dispute Resolution Process Flow Chart



* Disputes about market trading, settlements, power system operation directions and metering.
** All other cases
† Clause 8.2.5(g) states that "the Adviser *may* then refer the dispute for resolution by a DRP [our emphasis] "

Table 7.1: Derogations from dispute resolution procedures[22]

State	Transmission		Di	
	Date	**Derogation**	**Date**	**Derogati**
Victoria	Ends 31/12/2000	Disputes resolved according to transmission licence.[23]	Ends 31/12/2000. Post 2000	Disputes licence. Disputes specified
New South Wales	Ends 30/6/1999	Transmission access disputes arbitrated by IPART under its Act.[25]	Indefinite Ends 31/12/2000 Post 2000	If Dispu Supply A Act. If dispute arbitrated code disp
ACT	Ends 30/6/1999	Disputes handled under legislation nominated by the relevant Minister.	Ends 31/12/2000	Disputes the releva
South Australia	31/12/2000	Arrangements yet to be detailed.	Indefinite	Regulator access dis

22 Does not include derogations on the regulation of network pricing.
23 NEC clause 9.7.1(c). Prior to 1 January 2001, transmission and distribution network connection will be regulated by the Office of the Regulator General under the Electricity Industry Act.
24 NEC clause 9.7.4(e). It is intended that the Regulator-General will apply the terms of chapter 5 (and not a specific Victorian access regime) until the Regulator-General ceases to regulate distribution network pricing: Application, p197.
25 Independent Pricing and Regulatory Tribunal: code 9.15.1.

7.3.2 What the participants say

Many of the access concerns raised in submissions focused on the potential problems for participants in interpreting the code, users negotiating with a monopoly provider and small users in particular complying with complex technical standards. All of these concerns emphasise the likelihood of disputes arising between participants, potentially delaying or thwarting access to the use of electricity infrastructure.

The capacity of participants to handle disputes effectively, simply and quickly through code processes ought to be a key way of meeting these concerns and maintaining confidence of users, providers and the public in the code.

In this context, several submissions (eg Energy Users Group, Boral, Environment Australia) called for wider representation on code administration bodies and panels including the Dispute Resolution Panels. They nominated such interests as small participants, end user experience, participants with alternative generation and energy efficiency backgrounds and external interests such as the gas industry. In particular, the Energy User's Group (sub., pp. xiv, 14) argued that:

> NECA and NEMMCO who will jointly be responsible for administering the NEM need to be impartial and keep their charges to a minimum, but also have adequate resources to fulfil their responsibilities. Users must be assured of these outcomes. The new institutions need to establish effective links with end-users and involve users in their various committees and panels. ... This needs to be done for at least the code Change Panel, Dispute Panel, Reliability Panel and Inter-regional Planning Committee.

Other participants (eg Australian Paper, Business Council of Australia and the Snowy Mountains Hydro–Electricity Authority) perceived a need to monitor the effectiveness and accountability of the code's self-regulatory processes and the code administration bodies. They also emphasised the need for derogations to end when the market is fully operating ie by 2000.

It is worth noting that related concerns — examined in chapter 4 — focussed on difficulties in interpreting the code, negotiating connection and complying with technical standards. These concerns also emphasised the likelihood of disputes occurring and the need for effective dispute management systems.

The joint submission of Victorian distribution businesses (sub., p. 24) highlighted that both state and national regulators will have responsibility for connection and pricing disputes post 2000. They requested that the same body be responsible for dispute resolution for pricing and connection post 2000. Yallourn Energy (sub., pp. 5–6) raised the issue of dealing with cross-border complaints or disputes where different regulations operate in each jurisdiction.

The consultant's report suggested that, where negotiations over connection are protracted with no agreement being reached, it is important that such disputes be resolved promptly, particularly in the case of vital reinforcements to the network. They also suggested an alternative process where the IRPC could review the connection or augmentation proposal with a final decision made by NEMMCO.

7.3.3 The Commission's considerations

In its draft decision, the Commission sought to ensure that the code's dispute resolution processes were adequate in terms of serving:

- the interests of providers and users in having a fair, responsive, affordable and well-defined means of resolving disputes through an impartial assessment of the participants' rights, obligations and claims; and

- the public interest in establishing and maintaining confidence in the administration and implementation of the code not just for the benefit of code participants but all people affected by the use of electricity.

The Commission's analysis examined the effect on these interests in terms of the ability of the code processes to accommodate:

- coverage of appropriate parties;
- principles of natural justice;
- prompt settlement of disputes; and
- uniformity and impartiality as to:
  - procedures;
  - mediators/arbiters;
  - publication of decisions; and
  - scope for appropriate appeal.

The Commission also examined the provisions relating to internal DMSs.

Coverage

The connection provisions and the explanations in the NECA submission intend that both existing and intending code participants (including new connection applicants) are covered by the code including the dispute provisions in chapter 8.

In its draft decision the Commission considered that more clarity was needed as to who, and what type of dispute, is covered by the dispute provisions in chapter 8. Chapter 8 confines its coverage to code participants who are defined in chapters 2 and 10 as participants registered with NEMMCO (under various categories) and by implication already connected to the network. However, clause 2.8 allows intending participants to register under the category relevant to them before acting in that capacity. In addition, clause 2.3.5 (d) explicitly states that an intending customer 'acquires the benefits of the access provisions of chapter 5 and the administration provisions of chapter 8 for matters connected with any intending load. However, a number of participants, such as Sithe Energies (sub. attach., p. 10) indicated that this coverage of both existing and *intending* participants is not obvious from reading the start of chapter 8. Based on this uncertainty, the Commission's draft decision stated:

> **Chapter 8 of the National Electricity Code must indicate clearly that all intending participants, connection applicants and their connection arrangements are covered by the code's dispute resolution provisions.**

Dispute resolution is important in the context of new connections because the nature of the connection process is prone to disagreements, new connection applicants are likely to have disadvantages in bargaining power and new connections may represent new entry into the electricity market. At the same time, it needs to be clear that the dispute processes governing access arrangements apply only to those participants who have, or intend to have, a direct connection agreement with the network service provider.

Natural justice and effective dispute management

The stated objectives of the code's dispute provisions emphasise the rules of natural justice and encourage simple, quick and inexpensive measures without resort to formal legal procedure or representation. At the same time there is provision for parties to put their case and have legal representation where it is necessary to accord the parties natural justice or for other reasons appropriate to the circumstances. The objectives also emphasise the need to restore or enhance the relationship between the disputants. Overall, effective dispute management based on natural justice is a basic theme in these provisions.

However, in its draft decision the Commission expressed concerns that, in the NEM's infancy, disputes would need to be settled with due regard to the views of all participants who may have an interest in the subject matter of a dispute. The Commission took the view that the Panel procedures should stipulate that the Panel must consult with parties who may have a relevant interest in a dispute. Consequently, the Commission's draft decision stated:

> **The code must be amended so that the Dispute Resolution Panel's procedures stipulate that it must consult with parties who may have a relevant interest in a dispute.**

The articulation of these principles in the guiding objectives of the dispute management provisions sends an clear signal to both users and providers that fairness, due process and transparency are the benchmarks for resolving disputes and creating effective dispute management systems.

The Commission concluded overall that the code acts in the interests of facility owners and network users by including, and basing the dispute management procedures on, principles of natural justice and effective dispute management.

Prompt settlement of disputes

As noted above, the emphasis in the code is on cost effective, timely resolution which is strengthened by an obligation on the disputing parties to act in good faith and use all reasonable measures to resolve the issue. Deadlines are set for each part of the process to minimise delay in resolving the dispute. Nevertheless, parties may seek an urgent injunction from a competent court, thus preserving their right to take more immediate action on the dispute.

The time lines in the code, with the distinction between more and less urgent matters, assist parties to estimate the time and resources they need to commit to each stage of the process as well as attain a reasonable idea of how quickly their dispute will be managed. Not only does this benefit the parties but it is in the public interest that the limited resources of the dispute arrangements are employed prudently and on the issues likely to have the most significant effects on users, provider and the public overall. At times, parties may decide to settle the issue themselves without invoking more time-consuming processes: this will be of public benefit where it allows the process to deal with more important matters.

The Commission considered that the code acts in the interests of facility owners and network users by including provisions that emphasise the timely resolution of disputes (ie time lines and court injunctions) but which also seek to balance procedural efficiency with a suitable regard for parties' exercise of their rights and obligations.

Uniformity and impartiality

All code participants and NECA are bound by the dispute resolution provisions. Moreover it is required that the Dispute Resolution Adviser and Panels should be competent but without any conflict of interest in regard to an individual dispute.

At the same time, the provisions allow for flexibility so that appropriate decisions can be made according to the circumstances and issues involved. The stated objectives and subsequent provisions stress the need for responsiveness and timeliness in decision making. Participants will be able to design internal dispute processes relevant to their situation, while conforming with criteria to be developed by NECA. The composition of a Dispute Resolution Panel must be suited to the particular circumstances including expertise in the field to which the dispute relates.

The Commission believes this approach balances the flexibility required to cater for the diversity of users' and providers' interests in a dispute with a suitable degree of uniformity and predictability as to the resolution procedures involved. The requirement of an impartial Adviser and Panels should result in a system which is unbiased in terms of no single interest being favoured over another. At the same time, the requirement of expertise should bring competence to deal with the complex matters likely to arise in an access dispute.

Nevertheless, in its draft decision the Commission observed that the capacity for disinterested decision-making would be enhanced if the membership of panels could be drawn from a wide spectrum of relevant interests and views, thus increasing the opportunity for issues under dispute to be assessed from a variety of relevant viewpoints. At the same time, selection onto a panel should be on the basis of merit including the ability to act diligently and reasonably in the interests of participants and the public overall, rather than representation of a particular industry sector.

Accordingly the Commission considered the code could be improved by nominating a more representative range of user and provider interests that the Adviser should consider in constituting a Panel. Specifically, the Commission's draft decision stated that:

> **To improve the efficient operation of the access code's procedures the code should widen the representation on the National Electricity Code Administrator and the membership pool for the Dispute Resolution Panel, with due regard to expertise in dispute resolution and industry operations.**

Publication of decisions

While there is no provision for publishing the results of disputes resolved through internal processes, this may be a matter which NECA will address in its guidelines on internal dispute management systems.

The Commission considers that, to be effective, dispute mechanisms must be publicly perceived as being fair, accountable processes which result in binding and workable decisions. Given the newness of the code in terms of access and market arrangements, it also is important to give third parties additional guidance on the code's interpretation and implementation. The Commission believes that the regular publication of information to participants is a good basis for establishing and maintaining such confidence. Publication of decisions also can be productive in:

- yielding useful feedback on the adequacy or otherwise of code provisions or operations; and
- assisting participants to resolve future disputes involving similar issues based on precedents decided by the adviser or panel.

This should also provide a useful source of information in response to a major concern of both users and providers regarding the availability of information on how the code is operating and on decisions likely to affect their interests.

Publication of information in this context is also in the public interest, again in fostering confidence in the code's administration and in providing a basis for more informed decisions by participants in negotiating access as a prelude to entry into the competitive side of the market.

Rights of appeal

Resolution of a dispute by way of agreement or determination by the Adviser or Panel will be binding on the disputing parties. Although there are not rights of appeal as such from one stage of the dispute process to the next, failure to resolve a dispute will often be the trigger for moving to a more formal reconsideration and mediation/ arbitration of the issues on their merits.

As noted before, parties have a standing right to apply to a court for an injunction regarding the dispute. In addition, questions of law which arise during a dispute may be determined by a court of competent jurisdiction. This limited right of referral or appeal has two related effects:

- it maintains the ability of the dispute process to produce final decisions, especially on issues of fact; and yet

- it preserves the rights of parties to have outstanding legal questions decided by an authoritative body (ie the court).

The provision by the code of an independent forum of appeal is another means of injecting independence and impartiality into the dispute process. The confidence of users and providers in bringing matters to the dispute process will be enhanced because legal decisions affecting their interests can be reviewed by a recognised authority.

The only potential drawback is that, while courts may be expert on the relevant legal issues, the complexity of the code and technical matters may require additional expertise not available to the court. However, this can be addressed by such measures as the use of expert evidence and the appointment of acknowledged experts as independent advisers to the court.

It is in the interests of users, providers and the public that the dispute arrangements produce clear, binding and final decisions without unduly compromising the benefit of having important legal questions determined in an authoritative manner. The Commission believes the present arrangements give sufficient weight to each of these factors in defining the scope for appeal from a dispute outcome.

Internal dispute mechanisms

The first stage of the resolution process will rely on the internal dispute management systems (DMS) adopted by individual participants, subject to the criteria and guidelines devised by NECA. The ideal of effective resolution of disputes at an early stage will be tested by the adequacy of these DMSs

Given the importance that it places on the timely resolution of disputes, the Commission raised the issue of time lines with NECA as a feature to be included in the internal dispute guidelines. More generally, the Commission indicated it would assess, and advise on, the guidelines in terms of their capacity to balance the interests of providers, users and the public interest (including the competition objectives of both the code and Part IIIA).

State and Territory derogations

Consistent with a transitional period to adjust to the code, access dispute resolution will be regulated by jurisdictional laws and regulators over that time. The Commission recognises that this transition is a necessary feature of reform of the access and market arrangements in each jurisdiction. In Victoria and New South Wales participants are now making market, access and investment decisions subject to a competitive environment. In South Australia, the Australian Capital Territory and Queensland, governments are carrying out electricity review and restructuring.

For the most part, the transitional phase will be completed by 2002. Even so, uniformity and certainty was a common theme in participants' responses, especially network users. The Commission too had misgivings about some of the arrangements for access dispute resolution, namely:

- the lack of a final date for the Victorian derogations on distribution and the continued use of Victorian (rather than code) dispute procedures;
- the content and timing of South Australian dispute regulation, including the suggestion that commitment to the code will depend on the code adjusting its access arrangements to South Australian conditions; and [26]
- the degree of autonomy from government in the ACT regulatory arrangements.

The Commission's draft decision recommended that arrangements for dispute resolution should be uniform at the end of the transition phase. Specifically it stated;

[26] Both Queensland and South Australia have instituted major reviews of their electricity access, market and regulatory arrangements with a view to enacting reform legislation during 1997.

The code must be amended so that, by 2001, the dispute regime administered by each jurisdictional regulator are either based on, or compatible with, the code's dispute provisions. Each jurisdiction should also commit to definite deadlines for their derogations.

7.3.4 The applicant's response

Since the draft decision, the applicant stated that it was always intended for intending code participants, registered with NEMMCO under the provisions of clause 2.8, to be able to use the dispute resolution procedures of the code and the code would be amended to clarify this position beyond any doubt. Consequently, the applicant amended the code to make explicit that disputes involving the proposed access arrangements or connection agreements of intending customers or connection applicants are covered by the dispute resolution provisions. In particular, clause 8.2.1(a) has been amended and clause 8.2.1(a)(5) inserted so it now states:

> (a) The dispute resolution regime provided for in this clause 8.2 applies to any dispute which may arise between any *code participants* (and for the purposes of clause 8.2, "*code participant*" includes ~~*NECA*~~, *Connection Applicants* and, for the avoidance of doubt, *Intending Participants*) as to:
>
> (5) a dispute concerning the proposed *access* arrangements or *connection agreements* of an *Intending Participant* or a *Connection Applicant*; or

In response to the Commission's other concerns about the operation of the code's dispute resolution procedures, NECA committed itself to considering these issues as part of its review of dispute resolution arrangements as required under clause 8.2.13 of the code.

In addition, since the pre-decision conference, the Commission has been informed that the ACT Assembly passed legislation in October 1997 establishing access dispute arrangements to be administered by a statutory regulator, the Independent Pricing and Regulatory Commission. These changes have also been reflected in amendments to the ACT's derogations, in particular clauses 9.22.2(a) and 9.22.3(a) which establish IPARC as the body responsible for resolving access disputes regarding transmission and distribution networks in the ACT up until 1 July 1999.

7.3.5 The Commission's findings

The Commission considers the code's principles and general mechanisms for handling disputes act in the interests of facility owners and network users by:

- establishing a framework for uniformly applying procedures which can accommodate the diverse interests of all parties;
- being based on natural justice principles such as due process, rights of reply and representation, and publication of decisions;
- emphasising cost effective resolution with opportunity for disputes to be resolved mutually at the appropriate level;
- arranging for independently conducted mediation/ arbitration; and
- allowing scope for appeal to a competent court.

Because interpretation of the code can lead to different outcomes, disputes are likely in the NEM's implementation, especially in the early stages when established precedents are not available. It is vital to the interests of facility owners and network users that they have ready access to a range of uniform but flexible procedures which allow them to resolve disagreements in a timely fashion. The dispute provisions balance the interests of participants with the broader public interest by leaving the initiative for resolving disputes with participants themselves while still establishing standards (eg through guidelines) and scope for impartial review (eg dispute panels and court appeals). Accordingly, the

Commission believes the code provides such mechanisms as well as arrangements for identifying systematic problems (thus assisting code changes) and publishing decisions.

The Commission considers that the code amendments which make explicit the coverage of intending participants and connection applicants properly address this issue and improve the rights of network users under the dispute resolution arrangements.

In addition the Commission has been kept informed of the development and implementation of the guidelines which will establish procedures for the internal dispute resolution mechanisms (ie the first stage of the code's dispute arrangements).

Overall, the Commission considers that these guidelines[27] are appropriately designed to:

- be used by participants, end use customers and regulators;
- deal flexibly with a wide range of conflicts and disputes;
- emphasise the importance of mediation and conciliation;
- involve expert and other third party assistance as required;
- document clearly the progress of individual disputes; and
- provide administrative support and facilities to the disputing parties.

The guidelines also integrate well with the other dispute resolution procedures set out in chapter 8 and should prove to be a important resource for facility owners and network users.

The Commission notes the applicant's response to consider as part of its review the membership of a Dispute Resolution Panel. Nevertheless, the Commission maintains its view that the code needs to demonstrate that the group from which Panels are selected will be representative of the diversity of user and provider interests. This would extend the range of expertise available and maintain confidence in the code's capacity to accommodate that diversity of interests. The Commission also notes that this issue was initially raised by user groups and alternative energy interests, whose concerns are relevant to the environmental and consumer interests that the Commission must consider in assessing the code.

For these reasons, the Commission believes that it is important that this aspect of the dispute resolution provisions reflects the diverse interests involved in the access arrangements and electricity market. Accordingly, clause 8.2.2 (c) should indicate the areas of the industry and market from which the dispute panel group is to be selected.

The Commission notes the applicant's response that consultation by the Dispute Resolution Panel will also be considered in its review of dispute resolution arrangements. However the Commission considers that the applicants need to develop more detail on how this will be achieved and what the scope of the Panel's duty to consult will be in practice. In essence, the Commission believes that the Panel should have an obligation to consult widely with affected interests, rather than a discretion.

The Commission considers that it is important that, at the end of the transition period, the dispute regimes for both transmission and distribution need to be consistent across the electricity market and compatible with the dispute procedures set out in the code. As in other areas, the code must demonstrate that facility owners and network users will be treated equitably and consistently in terms of the code's procedures and safeguards, irrespective of jurisdiction. It is equally important that the code indicates a common end date for the jurisdictional dispute derogations in chapter 9, which ought to be the same as the end date decided for technical standards, that is by 31 December 2002 at the latest.

The Commission is satisfied, on consideration of the ACT legislation, that the regulatory arrangements concerning access disputes in that jurisdiction will be autonomous from government and will follow procedures which adequately accommodate the interests of facility owners and network users.

[27] *National Electricity Market Dispute Management System: the DMS Criteria*, January 1998.

In general, the Commission is satisfied that its major concerns regarding dispute resolution have either already been addressed or, on the basis of NECA's commitment, will be addressed in a forthcoming review. Nevertheless, the Commission considers the benefits to facility owners and network users arising the dispute provisions would be enhanced if the code was amended:

1. **To widen the representation on NECA and the Dispute Resolution Panels pool, with due regard for expertise in dispute resolution and industry operations. Clause 8.2.2 (c) should indicate the areas of the industry and market from which the dispute panel group is to be selected.**
2. **So that the Panel procedures stipulate that the Panel must consult with parties who may have a relevant interest in a dispute. The definition of 'interested party' in chapter 10 should also be amended to take account of persons interested in the subject matter of a dispute.**
3. **So that the dispute regime administered by each jurisdictional regulator will be either based on, or compatible with, the code's dispute provisions. Each jurisdiction should also commit to definite deadlines for the cessation of their derogations by 31 December 2002 at the latest.**

7.4 Enforcement

7.4.1 Issues for the Commission

While disputes focus on disagreements within the boundaries of the access code, enforcement focuses on remedies and actions when a participant steps outside the code's boundaries. The code's effectiveness will depend on participants and code bodies complying with its provisions. Accordingly, the Commission stresses the need for effective compliance and enforcement mechanisms for the code to operate as the primary means of guiding participant behaviour in the new access and market environments.

Demonstrable compliance with the code by participants will strengthen confidence in the code as a workable instrument for implementing electricity industry reform, particularly in the initial stages of the market. Due to the impact breaches of the code may have on other code participants and members of the public, it is important that the code provisions operate effectively. Consequently the Commission believes that it will be in the interests of facility owners, network users and the wider Australian community if the code's enforcement provisions are designed to:

- deter contraventions of the code by providing:
  - adequate incentives and disincentives to promote compliance;
  - a prompt and efficient response to breaches; and
  - a clear statement of code participants' obligations subject to the requirement of flexibility to meet the needs of code users.
- to promote confidence in, and support for, the code by providing:
  - compensation for individuals suffering loss or damage arising from the breach;
  - fair and transparent procedures which comply with the principles of procedural fairness (see Box 7.1);
  - consistent decisions; and
  - proportionality between breaches and penalties.

7.4.2 What the applicant says

The applicant indicated that the enforcement powers contained in the code and National Electricity Law (depicted in Figure 7.2) are intended to ensure 'that the code provisions are effective and adhered to by service providers and network users'.

These powers are largely contained in the National Electricity Law (to be enacted in each of the participating jurisdictions), under which:

- service providers and network users must be registered with NEMMCO. As part of being registered, participants agree to abide by the code provisions;
- penalties will be prescribed for code breaches;
- NECA has the power to investigate possible code breaches, and to impose limited penalties or apply to the National Electricity Tribunal for an order;
- questions of law are appealable to a State Supreme Court; and
- penalties imposed by the Tribunal are recoverable through debt recovery courts.

The implementation of the code relies on section 9 of the National Electricity Law which imposes a penalty on service providers and network users who are not registered by NEMMCO as code participants. Registration requires the code participant to be bound by the code or subject to a derogation under the code.

Regulations will prescribe the code's provisions as either Class A, B or C. Breaches of these provisions may give rise to civil penalties, as follows:

Provision	**Initial penalty ($) not exceeding**	**Continuing penalty ($)**[28]	**Administered by**
Class A	20 000	No penalty	NECA
Class B	50 000	10 000 per day	Tribunal
Class C	100 000	10 000 per day	Tribunal

Breaches of other code provisions which are not classified by regulation, may also give rise to a civil penalty not exceeding $20 000.

Enforcement proceedings: code breaches

NECA is primarily responsible for investigating and enforcing code breaches, although code participants have limited rights to enter and inspect another participant's facility.

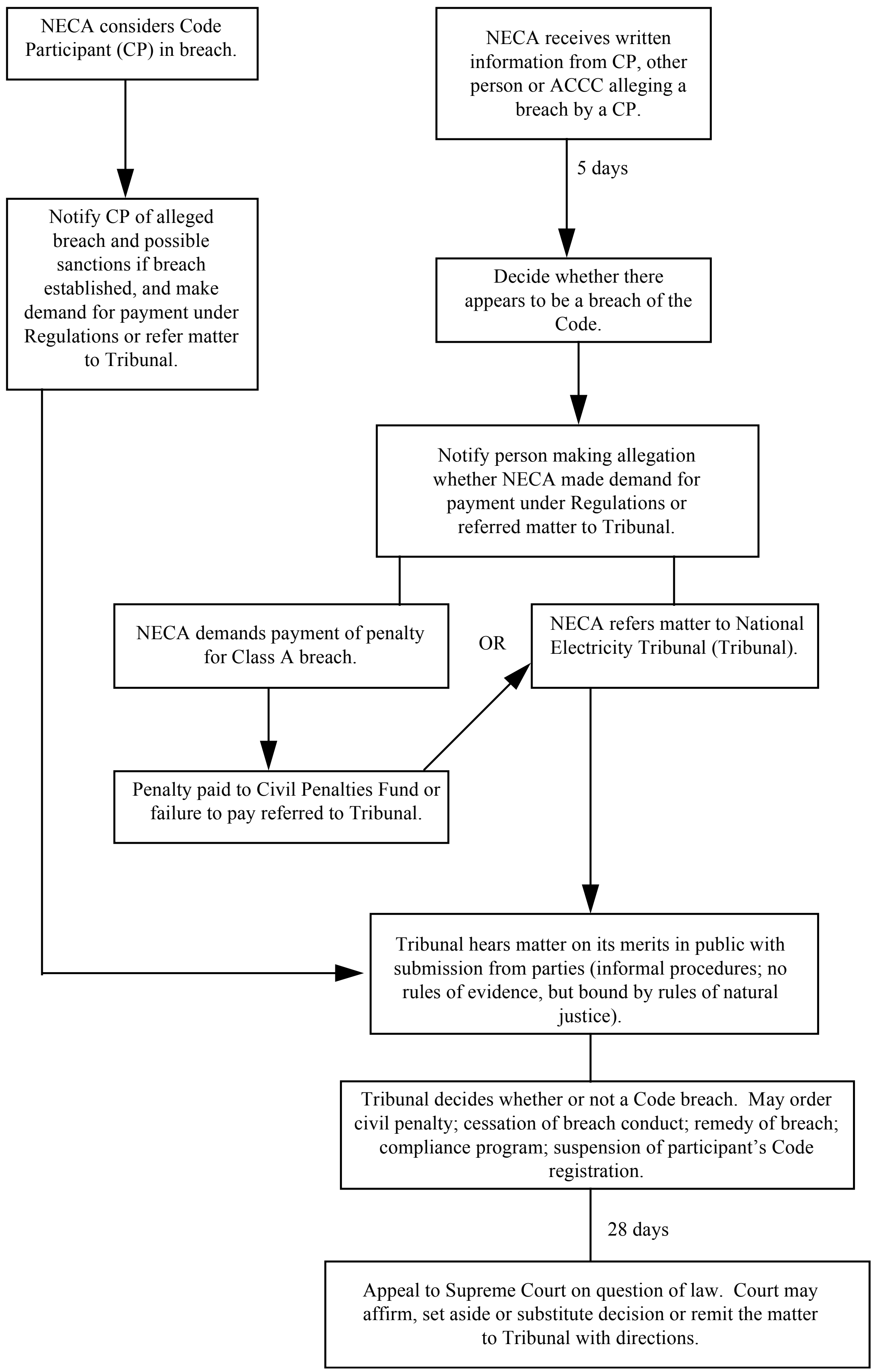
In performing this function, NECA may request information, initiate investigations and exercise rights of entry and inspection (as defined by the National Electricity Law) in respect of possible code breaches.

If NECA receives written information alleging a breach of the code, NECA must determine whether there is a code breach within 5 business days of receiving the information, and notify the person making the allegation of NECA's response.[29]

28 Imposed for each day the penalty continues after service by NECA of notice of the breach.

29 If the person providing the information is dissatisfied with a decision by NECA not to refer the matter to the Tribunal, they may provide further information and request NECA to reconsider.

Figure 7.2: Enforcement



If NECA considers that a code participant may have breached the code and that sanctions would be appropriate, NECA must notify the code participant of the alleged breach.[30]

If a code participant breaches a Class A provision, NECA may notify the code participant to pay the prescribed civil penalty. The participant then has 28 days to pay the amount or apply to the National Electricity Tribunal for a review of the decision. If the code participant fails to take the specified action, the Tribunal, on application by NECA, may make an order that the amount be paid.

If NECA considers that a code participant has breached any provision of the code, NECA may apply to the National Electricity Tribunal for an order. The Tribunal:

- must declare whether or not the participant is in breach of the code;
- can make orders requiring the participant to pay a civil penalty;
- can impose a requirement on the code participant to:
  - cease its breach of the code;
  - take action to remedy a breach of the code;
  - implement a specified program for compliance with the code; or
  - any combination of these; and
- can suspend the registration of the code participant or suspend the participant's code rights.

Unless the Tribunal directs otherwise, each party bears its own costs. Parties to the proceeding can appeal questions of law to the Supreme Court.

Either NECA or NEMMCO may direct a code participant to 'do or refrain from doing anything' which NECA or NEMMCO thinks necessary or desirable to give effect to any order of the Tribunal.[31] An order by the Tribunal for payment of a civil penalty may also be registered in a court having jurisdiction for the recovery of debts up to the amount of the civil penalty.[32] Proceedings for enforcing that order may then be taken as if the order were a judgment of the court. Civil penalties must be paid into a civil penalties fund established by NECA.[33]

Every six months NECA must publish a report summarising:

- matters referred to the Tribunal in the previous six months;
- all findings of the Tribunal during that period; and
- any demand for payment made by NECA under the Regulations or sanctions applied by the Tribunal under the National Electricity Law.

NECA may publish additional reports on specific Tribunal matters and findings, including any sanctions imposed by NECA or the Tribunal. A decision by NECA to publish an additional report is a reviewable decision.

Other enforcement proceedings

Where there is an alleged contravention of the code, section 10 of the National Electricity Law allows code participants to bring an action against other code participants provided that the contravention gave the defendant an obligation or liability to them. Likewise, where NECA allegedly contravenes the code, code participants may bring an action against NECA provided that the contravention gave NECA an obligation or liability to them.

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30 NECA may refer an alleged breach to the Tribunal without information from a third person.

31 This allows NECA to direct a NSP to disconnect a code participant from any transmission or distribution system. An appeal to the Supreme Court does not affect the operation of the Tribunal's decision unless the Supreme Court orders otherwise.

32 The NEL also allows a code participant to go the courts to recover any code related debts not paid within 28 days after the due date.

33 Money from this fund may be applied only in payment of Tribunal costs and expenses (including staff and services); NECA costs and expenses; and liabilities and expenses of the fund.

The code puts particular emphasis on participants complying with system security directions issued by NEMMCO under chapter 4 of the code or section 76 of the National Electricity Law. A failure to observe such a direction is deemed to be a breach of the code. Any code participant who is aware of such a failure must refer the allegation to NECA.

In addition to the code's enforcement procedures, under Part IIIA of the TPA, the ACCC may enforce an undertaking against the relevant network service provider in the Federal Court. The Court is empowered to make a range of orders to achieve compliance with the undertaking and compensate third parties for loss or damage. As the code will eventually be brought to the Commission as an undertaking, these enforcement procedures will also apply to facility owners.

In response to NECA's application, participants did not comment on the enforcement arrangements for the access code.

7.4.3 The Commission's considerations

The application recognises the need to ensure that the code provisions are effective and adhered to by service providers and network users. Consistent with this view, the Commission considers that the proposed access code and National Electricity Law promotes the interests of facility owners, network users and the wider Australian community by possessing many of the features necessary for effective enforcement. For example, the code and National Electricity Law:

- use deterrents and penalties (such as fines and disconnection) as disincentives against behaviour detrimental to code and market objectives;
- require NECA to respond promptly to every allegation received;
- outline a common set of procedures and principles to be followed in gaining access;
- require compliance with definite standards to meet system security and technical obligations;
- allow the Tribunal to order the code participant to remedy the breach; and
- require NECA to publish a report summarising the Tribunal's decisions.

However, in its draft decision the Commission identified several areas which could detract from the code's operation, in particular the lack of clarity in the legislative machinery underlying the enforcement procedures.

Failure to register with NEMMCO

Section 9 of the National Electricity Law ensures that the code operates as the primary means of regulating access to the national electricity grid and market by requiring participants to register with NEMMCO. However, the procedure for bringing proceedings under s. 9 for failure to register are unclear and require further clarification. In particular:

(a) The penalty suggests that a contravention notice in respect of s. 9 is to be served on the defendant by NECA. As the National Electricity Tribunal does not have the jurisdiction to hear proceedings for such contraventions, it is unclear whether NECA also has the responsibility of bringing the proceedings in the appropriate State court.

(b) The omission of the word 'civil' from the phrase 'maximum penalty' suggests that a breach of s. 9 is a criminal offence.[34] It should be clarified whether it is intended or not that NECA prosecutes a contravention of s. 9 as a criminal offence.

In its draft decision the Commission argued that the expected benefits from the NEM access code would be raised if:

[34] NEL Schedule 1 cl 37 states that a penalty specified at the end of a subsection indicates that a contravention constitutes an offence. "Offence" generally indicates that the provision is a crime.

the procedure for bringing proceedings under section 9 of the National Electricity Law was clarified, including the question whether NECA would be able to prosecute such proceedings.

NECA indicated that it is intended that a breach of s. 9 be prosecuted as a criminal offence and that NECA would provide the necessary information and evidence to the prosecuting authorities. If prosecution is appropriate but the relevant DPP does not wish to proceed, NECA would prosecute. This raised an issue of whether NECA, as a private corporation, has jurisdiction to prosecute.

Code contraventions

Together, section 9 of the National Electricity Law and the regulations prescribing the code provisions as Class A, B or C will provide an incentive for code participants to comply with the code.

Due to the difference between the civil and criminal standards of proof, the imposition of civil as opposed to criminal penalties for code breaches should increase the likelihood of penalties being imposed, and thus the deterrent effect of the regulations. However, until the regulations classifying the code provisions are adopted, the Commission cannot assess the proportionality between the contravention and the penalty.

In the absence of more information the Commission was concerned that:

- delay in publishing the regulations will add to the uncertainty as to how effectively the code will operate in practice;
- the range of penalties may be limited and inflexible in meeting the diverse circumstances of different breaches; and
- penalties may be inappropriately severe or lenient in response to particular breaches.

As a result of these concerns the Commission's draft decision stated that:

the draft regulations classifying code provisions as Class A, B or C should be made available for public comment with a commitment to finalise them before the national market commences.

Bringing an action

Although NECA is intended to have primary responsibility for taking action against code participants who breach the code, section 10(1) of the National Electricity Law allows a person to bring proceedings against NECA or a code participant for code breaches. In order for this provision to operate effectively, the Commission's draft decision recommended that the following issues should be clarified:

(a) Where NECA or a code participant has breached the code, section 10(1) allows a person to bring proceedings against NECA or the code participant provided that the contravention gave 'rise to an obligation or liability of NECA or the code participant' to the person bringing the proceeding. It is not clear from the code or the National Electricity Law, which provisions will give rise to this type of 'obligation or liability'.

(b) Section 10(1) allows certain persons to bring proceedings against NECA in respect of a contravention of the code. However, under section 10(2), both parties to the proceeding must be code participants. As NECA is not a code participant,[35] s10(2) appears to exclude action being taken against NECA under s10(1).

(c) Proceedings under section 10(1) may not come within the Tribunal's jurisdiction. The Tribunal's functions may need to be rewritten to accommodate the right of code participants to bring actions over contraventions which affect their interests.

Given this range of concerns, in its draft decision the Commission stated:

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[35] NECA is a code participant for the purposes of the dispute provisions in clause 8.2 of the code but not for enforcement or other code purposes: see clause 2.1.2(b)

the right of code participants to bring an action against NECA and other code participants in respect of an alleged contravention of the code should be clarified.

In its initial response, NECA advised that section 10(1) is intended to preclude proceedings where there is no detriment to a third party. It will be the responsibility of the party alleging damage to prove that an obligation or liability exists under the code or Law and has been breached. Proceedings outside the Tribunal's jurisdiction are commercial actions and so will not be heard by the Tribunal but rather will be handled through the code's dispute procedures.

NECA also stated that, since it is a non-profit body charged with administering the code, it is not appropriate that NECA be open to actions brought by participants for alleged breaches of the code. However, NECA points out that section 10(3) provides that actions can be brought against NECA in terms of its conduct on grounds which do not rely on the code.

Without any success, the Commission, in its draft decision, requested the views of participants and other interested parties with respect to NECA's response, in the light of its comments on NECA's accountability.

Tribunal Orders

The range of orders which the Tribunal may make are sufficient to allow the Tribunal to develop appropriate remedies for code breaches. The registration of civil penalty orders in a court will facilitate enforcement of the Tribunal's orders.

The code states that the Tribunal can issue orders to disconnect a participant as the ultimate sanction for a default event as defined in the code. However, there is no explicit provision in the National Electricity Law for the Tribunal to order disconnection: the most relevant power would seem to be the Tribunal power to suspend the rights of a code participant.

The lack of a clear power to disconnect may mean a Tribunal disconnection order could be challenged on the grounds of validity. The Commission believes that at an appropriate time at or shortly after the commencement of the NEM, the Law should be amended to include a specific power enabling the Tribunal to disconnect a participant in breach of the code. Specifically, the Commission's draft decision stated:

the National Electricity Law should explicitly grant the Tribunal the power to order disconnection.

Cross-vesting arrangements

The Tribunal is empowered to adjudicate the code through a variety of orders and penalties set out in the Law and Regulations and its orders can be enforced through the Supreme Court of each jurisdiction enacting the Law. Similarly, the Commission is empowered under Part IIIA to enforce access undertakings and other provisions of the Trade Practices Act in the Federal Court. It is likely therefore that similar matters may come before different courts which may result in divergent decisions.

As a result of these concerns in the draft decision the Commission stated that:

NECA should examine existing State and Commonwealth cross-vesting provisions to determine whether they will be sufficient to ensure the minimum amount of duplication and inconsistency in regard to the enforcement of the code, the Law and access undertakings in the Supreme and Federal Courts.

Natural justice and efficient breach management

The National Electricity Tribunal processes allow for: disclosure of interests; pre-hearing conferences; representation of parties; public hearings; minimal formality of proceedings; written reasons for its decisions; and an avenue to appeal on questions of law.

Consequently, the Commission believes that the provisions establishing the Tribunal are in the interests of facility owners, network users and the wider Australian community as they achieve an appropriate balance between an efficient response to breaches and procedural fairness.

To a lesser extent, NECA is also accountable for its conduct. The requirement to give feedback to informants ensures NECA promptly responds to every complaint received. In addition, there is an avenue to appeal against a decision by NECA to impose a Class A penalty, and NECA has an obligation to publish a half-yearly report on Tribunal matters and findings.

However, under the code, NECA has been granted broad powers including the power to request information for investigations, and to unilaterally impose a penalty for Class A provisions. These powers do not appear to be subject to any explicit procedural fairness requirements. For example, NECA is not required to provide participants under investigation an opportunity to respond to allegations, nor to provide participants with reasons for NECA's decision to impose a Class A penalty. In addition, a decision by NECA not to apply to the Tribunal alleging a breach of the code by a participant or to bring proceedings against a participant, is not a 'reviewable decision'.

Even though the code may not specify procedures which NECA must follow in performing these functions, NECA's decision-making process will be subject to the common law rules of procedural fairness. However, relying on this approach alone brings with it a degree of uncertainty and raises the potential for litigation from aggrieved participants.

Consequently, the Commission indicated in its draft decision that it would be prudent to clarify NECA's procedural obligations by incorporating more explicitly transparent and fair procedures into NECA processes and decisions. It may also be prudent to clarify the rights of code participants to bring proceedings against NECA and other code participants in respect of code breaches under s. 10 of the National Electricity Law. In responding to these concerns, TransGrid supported the development of guidelines regarding NECA's investigation powers under clause 8.5.1 of the code, but suggested these guidelines are not necessary prior to market commencement.

On a related issue, where NECA initiates an investigation, the costs are to be borne by the participant under investigation, even where no code breach is found and there is no subsequent enforcement action. In its draft decision, the Commission stated that:

> **in those cases where an investigation by the NECA does not result in a penalty or Tribunal proceedings, then the NECA should bear the cost of the investigation.**

7.4.4 The applicant's response

In response to the Commission's concerns about the uncertainty surrounding the classification of code provisions, NECA has advised that the regulations are being drafted, they have been made available for comment by participants and others and are expected to be finalised before market commencement.

In relation to the Commission's remaining concerns over the code's enforcement provisions, the applicant stated that, it will consider the case for those amendments, in consultation with the participating jurisdictions when the first appropriate opportunity arises to amend the legislation.

7.4.5 The Commission's findings

In general, the Commission believes the code's enforcement procedures act in the interests of facility owners and network users by: including obligations on NECA to respond to allegations of a code breach; using deterrents, penalties and Tribunal orders as remedies for code breaches; and by requiring the Tribunal to adopt processes which are consistent with the rules of procedural fairness.

However, in assessing the code's enforcement mechanism's the Commission identified a number of deficiencies. Individually these deficiencies were unlikely to bring into question the enforceability of the code. Nevertheless collectively they created uncertainty of procedure and outcomes and therefore are likely to detract from the effectiveness of the provisions and are likely to have a detrimental impact on the interests of the facility owners and access seekers. Despite the Commission's concerns, participants generally did not comment on the code's enforcement procedures.

Nevertheless, the Commission believes that the applicant's response falls well short of a commitment to revise, clarify and stream line the code's enforcement arrangements. However, to the extent that it is the National Electricity Law which is deficient, then the problems fall outside the scope of the access code and the direct sphere of NECA's responsibilities. Nevertheless, given its concerns the Commission believes that the participating jurisdictions and NECA should conduct a review of the interaction of the National Electricity Law, the code and jurisdictional regulations.

The Commission also maintains its concerns on the need for explicit principles and procedures of natural justice to guide NECA's enforcement actions. The Commission considers that, apart from notifying the 'defendant' participant of the alleged breach and likely sanction, the emphasis in clause 8.5.4 is on NECA's response to the participant alleging the breach and its obligation to notify NEMMCO and jurisdictions of an impending disconnection. The Commission does not believe that clause 8.5.4 sets out specific requirements of natural justice and/or procedural fairness on NECA (particularly in contrast to the explicit obligations placed on the Tribunal by the National Electricity Law).

The Commission is of the view that NECA must, using the code consultation procedures, develop and implement guidelines and conditions in respect of the exercise of its investigation powers under clause 8.5. The guidelines and conditions must set out those matters which NECA must have regard to or be satisfied as to, prior to the exercise of its powers and also set out those circumstances in which, notwithstanding that no breach of the code by a code participant is subsequently found to have occurred, that code participant is to bear the cost of providing the information sought by NECA.

In particular the Commission recommends that:

a) NECA examine existing State and Commonwealth cross-vesting provisions to determine whether they will be sufficient to ensure the minimum amount of duplication and inconsistency in regard to the enforcement of the code, the Law and access undertakings.

b) Procedural fairness be incorporated into NECA enforcement processes and decisions. Using the code consultation procedures, NECA develop and implement guidelines and conditions in respect of the exercise of its investigation powers under clause 8.5.1. The guidelines and conditions set out those matters which NECA must have regard to or be satisfied with, prior to the exercise of its powers; and also set out those circumstances in which, notwithstanding that no breach of the code by a participant is subsequently found to have occurred, that participant is to bear the cost of providing the information sought by NECA.

Appendix A. Consultations

NSW/ACT consultations

Generators

Delta Electricity

Energy Horizons/Lend Lease

Macquarie Generation

Distribution Businesses

EnergyAustralia

Great Southern Energy

Financial Investment Trader

Macquarie Bank

NSW Generator & Transmission Network Owner

TransGrid

Victorian consultations

Generators

Australian Cogeneration Association

Ecogen Energy

Hazelwood Power

Distribution Businesses

Powercor

Solaris Power

United Energy

Customers

Alcoa

BHP

Vested Interests

Michael Gunter

South Australian consultations

ETSA

Appendix B. Submissions

NEM Code of Conduct Authorisation and Access Undertaking:
Parties who have made submissions.

Access Code†

ACTEW Corporation

BHP (+ supplementary submission)

Capral Aluminium (+ supplementary submission)

Colin Taylor(+ supplementary submission)

Energy Users Group (+ 2 supplementary submissions)

Goldfields Power/Normandy Power

Hazelwood Power

Sithe Energies Australia Pty Ltd (+ supplementary submission)

TransGrid (+ supplementary submission)

Authorisation‡

Alcoa Australia (+ supplementary submission)

Australian Chamber of Manufactures

Australian Chamber of Commerce & Industry

Australian Cogeneration Association
(+ supplementary submission)

Australian Paper (+ supplementary submission)

BHP

Boral Energy (+ supplementary submission)

Business Council of Australia (+ supplementary submission)

Citipower

Delta Electricity (+ 2 supplementary submissions)

Department of Primary Industries and Energy

Ecogen Energy

Electricity Week

EnergyAustralia

Energy Users Group

Environment Australia

Greenpeace

Michael Gunter

Hazelwood Power (+ supplementary submission)

Industry Commission

Integral Energy

Chek Ling

Macquarie Bank

Macquarie Generation

Queensland Electricity Reform Unit

National Farmers Federation

New South Wales Electricity Reform Taskforce

Northparkes Mines

Hugh R Outhred

The Partnership Group

Powercor/Eastern Energy/Solaris/United Energy Citipower (Joint Submission)

SEQEB

Sinclair Knight Merz (Zauner)

Sinclair Knight Merz (Popple)

Snowy Mountains Hydro-electric Authority
(+ supplementary submission)

South Australian Government (+ supplementary submission)

Tasmanian Government

TransGrid

Yallourn Energy

Victorian Power Exchange

† While these submissions deal primarily with Access Undertaking issues, some also include comments on authorisation issues.
‡ While these submissions deal primarily with authorisation issues, some also include comments relevant to the Access Undertaking.

Appendix C. Submissions regarding the draft determinations

NEM Code of Conduct Authorisation:
Parties who have made submissions in response to the draft determination and pre-decision conference.

Submission Author/s	Date Submitted	Submission Title
AMPOL[1]	17/9/97	Trade Practices Act 1974. Applications for Authorisation No's A40074; A4475; A40076
AMPOL[2]	2/10/97	Trade Practices Act 1974. Applications for Authorisation No's A40074; A4475; A40076
Australian Cogeneration Association (ACA)[1]	5/10/97	National Electricity Code
Australian Cogeneration Association (ACA)[2]	9/10/97	Qld and NSW Interconnector
Australian Consumers' Association	3/10/97	Australian Consumers Association Response to the Draft Determination.
Australian Paper	4/9/97	National Electricity Code: Response to the ACCC's Draft Determination
Boral Energy[1]	12/9/97	Draft Determination On Applications For Authorisation National Electricity Code And Application For Acceptance Of NEM Access Code
Boral Energy[2]	2/10/97	Re: National Electricity Market Access Code
Boral Energy[3]	8/10/97	Comments on IRH as Requested by NEMMCO
Boral Energy[4]	14/10/97	National Electricity Market Access Code — NSW Proposed Derogation
Business Council of Australia (BCA)	10/10/97	Supplementary Submission to the ACCC on the Draft Determination on the National Electricity Code
Cadia Mines	7/10/97	Re: NECA Review
CitiPower	3/10/97	National Electricity Code — Draft Determination
Consumers' Federation of Australia (CFA)	3/10/97	Letter Regarding Draft Determination
Delta Electricity[1]	12/9/97	Draft National Electricity Code Technical Derogations
Delta Electricity[2]	3/10/97	ACCC NEM code of conduct — Draft Determination Response from Delta Electricity
Eastern Energy	7/10/97	NEC: Application for Authorisation and Acceptance of Code Lodged by NEMMCO and NECA
Ecogen Energy[1]	12/9/97	Submission to ACCC Pre-decision Conference 18 & 19 Sept
Ecogen Energy[2]: Gill, Len	18/9/97	Reserve Plant Issues

Ecogen Energy[3]	29/9/97	Ecogen Submission to ACCC's NEC Draft Determination — Further Submissions Following Draft Determination Conference
Edison Mission Energy Australia Ltd (EME)	18/9/97	Comments from Edison Mission Energy Australia Ltd
Energy Brix Australia	3/10/97	Draft Determination on Applications for Authorisation of the National Electricity Code
Energy Users Group (EUG)	9/10/97	Submission on the ACCC Draft Decisions on the NEC Application for Authorisation and Industry Access Undertaking
energyAustralia	7/10/97	National Electricity Code Authorisation — Supplementary Submission
Ergon Energy	6/11/97	
Hazelwood Power[1]	12/9/97	Application for Authorisation National Electricity Code — Additional Submission Pursuant to Pre-decision Conference
Hazelwood Power[2]	3/10/97	Application for Authorisation National Electricity Code — Additional Submission Pursuant to Pre-decision Conference
Incumbent Generators — Yallourn Energy	6/10/97	Response Re: National Electricity Code Draft Determination
Incumbent NSW DNSPs — Integral	3/10/97	Response to the ACCC's Draft Determination
Incumbent Victorian Generators — Hazelwood	12/9/97	Application for Authorisation National Electricity Code
Incumbent Victorian Generators — Orr	18/9/97	Generator Derogations
Incumbent Victorian Generators — Orr	18/9/97	Prudential Counterparty Risk
Incumbent Victorian Generators — Orr	18/9/97	Settlement Residue & Inter-regional Hedging
Incumbent Victorian Generators — Orr	18/9/97	Participant Compensation Fund Payments
Incumbent Victorian Generators — Orr	18/9/97	VoLL Changes
Integral Energy	17/9/97	National Electricity Code Authorisation — Draft Determination
Loy Yang Power	3/10/97	NEC — Draft Determination
Macquarie Generation	17/9/97	National Electricity Code: Macquarie Generation Initial Response to ACCC Draft Determination
National Electricity Code Administrator (NECA)	3/10/97	Supplementary Evidence to the ACCC — Conditions of Authorisation of the National Electricity Code

National Standards Commission	11/9/97	National Standards Commission
New South Wales Treasury[1]	24/9/97	Interconnection of the NSW and Queensland Electricity Grids — Proposed Derogation to the National Code
Optima Energy	8/10/97	Submission regarding the draft determination
Outhred, Hugh	16/9/97	Temporal & Spatial Issues in a Competitive Electricity Industry & their Implications for the National Electricity Code
Pacific Power	15/10/97	TPA 1974 – Applications for Authorisation of National Electricity Code and National Electricity Market Access Code
Powercor	10/10/97	ACCC Draft Determination and Draft Authorisation of the National Electricity Code
Proponents of Qld/NSW Interconnector	10/10/97	Supplementary Information — Qld/NSW Interconnector
Queensland Treasury Corporation	5/11/97	Prudential Requirements Under the National Electricity Code
SEQEB	15/9/97	TPA 1974. National Electricity Code: Applications for Authorisation Numbers — A40074, A40075, A40076 lodged by NECA and NEMMCO — Application for Acceptance of NEM Access Code Lodged by NECA. Position Paper on Payments to Embedded Generators for Shared Network Benefits. Version 2
SMHEA[1]	11/9/97	SMHEA Response to Draft Determination on NEC
SMHEA[2]	3/10/97	SMHEA Supplementary Submission
Snowy Hydro Trading	11/9/97	Determinations on NEC
Solaris	18/9/97	ACCC National Electricity Code Draft Determination Response
South Australian Government[1]	17/9/97	Application for Authorisation: National Electricity Code Application for Acceptance: NEM Access Code
South Australian Government[2]	3/10/97	Application for Authorisation: National Electricity Code Application for Acceptance: NEM Access Code
South Australian Government[3]	12/11/97	Draft Determination on the National Electricity Code
Southern Hydro[1]	11/9/97	Response to the ACCC's Draft Determination
Southern Hydro[2]	29/9/97	Response to the ACCC's Draft Determination
TransGrid	2/10/97	Response to ACCC's Draft Determination
United Energy	6/10/97	National Electricity Code

Victorian Government	3/10/97	NEC draft Authorisation Determination — Victoria's Final Submission to the ACCC
Westcoast Energy	8/10/97	
Yallourn Energy	15/9/97	Version 1.0: ACCC Response Re: National Electricity Code Draft Determination

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