ACCC/AER Submission

Energy Reform Implementation Group

Response to Issues Paper

August 2006

Introduction

The Australian Competition and Consumer Commission (ACCC) and the Australian Energy Regulator (AER) welcome the opportunity to comment on the Issues Paper issued by the Energy Reform Implementation Group (ERIG).

The ACCC/AER notes that ERIG is to develop implementation arrangements for further reforms to the Australian energy markets in the following areas:

- Electricity transmission
- Electricity market structures
- Energy financial markets

The electricity transmission and electricity market structures work streams are directly relevant to the work of the ACCC and AER. Among its responsibilities the ACCC enforces section 50 of the *Trade Practices Act 1974* (TPA), which prohibits acquisitions that would result in a substantial lessening of competition. The ACCC/AER notes that the Issues Paper raises questions about the role of section 50 in considering electricity industry market structure issues. The AER is responsible for regulating the revenues of Transmission Network Service Providers (TNSPs) in the National Electricity Market (NEM) and promulgating the regulatory test. The ACCC/AER notes that questions concerning these roles are canvassed in the electricity transmission section of the Issues Paper.

This submission focuses on these two work streams, but also briefly comments on related financial markets issues.

Electricity transmission

- What is the appropriate role of transmission in the national electricity market and is that role being performed effectively today?
- Do the current arrangements create a stable framework for efficient investment in new (including distributed) generation and transmission capacity?
- How can a level playing field be established and maintained between the competitive elements of the market and the regulated natural monopoly elements?
- What is the role of the current regulatory test? Is it performing that role effectively? If not, what changes are appropriate?

Role of transmission

Transmission fulfils a number of crucial roles in the efficient operation of the NEM.

By connecting generators to distributors (from where the electricity is transformed and passed onto end users), transmission plays the fundamental transportation function for electricity. The significant capacity of transmission lines allows for the transfer of electricity at high voltages, effectively and efficiently transferring energy from the generation plant. The laws of physics and the fact that electricity cannot be stored means that transmission is an essential step in the electricity supply chain because it is required to deliver a product to the source of demand.

Electricity transmission facilitates generation competition. Generators have open access to transmission lines in the NEM. Open access provides generators with the use of the network on the basis of dispatch decisions made by the National Electricity Market Management Company (NEMMCO), the system operator, rather than having preferential rights to transmission capacity.[1] Transmission facilitates generation competition both within a region and between regions. This increased inter regional trade potentially reduces the ability for market participants to exercise market power. Interstate transmission also enables the greater sharing of reserve capacity within the NEM, which promotes the delivery of least cost, reliable electricity services.

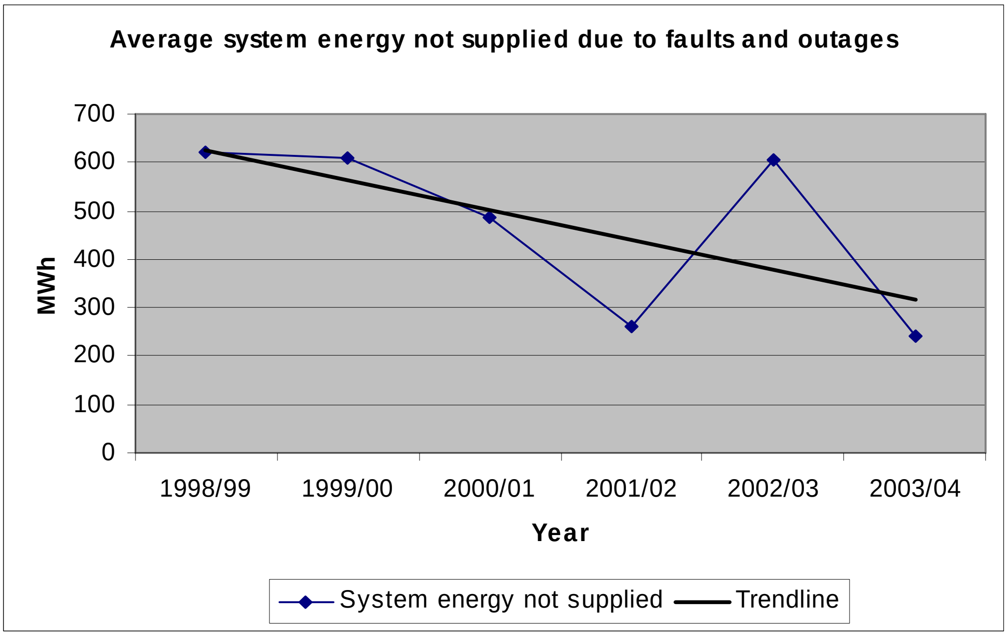
Efficient investment in transmission capacity is vital when considering the role transmission plays in the operation and efficiency of the NEM. The AER considers that the current regulatory regime for transmission investment provides a stable and effective framework for efficient investment in new electricity transmission capacity. Since the NEM's inception there has been significant network investment. Since the first transmission revenue cap the transmission sector has been provided over $5 billion in capital expenditure allowance to facilitate transmission investment. This figure represents half of the overall regulated asset base.[2]

However, an efficient transmission system is not simply a function of investment levels. It is also the result of effective planning, operation and maintenance and the setting of appropriate technical standards.

Since the commencement of the NEM transmission has continued to remain a highly reliable sector in the NEM. TNSPs regularly meet the minimum reliability performance requirements set out in schedule 5.1 of the Rules as well as the jurisdictional obligations contained in state-based statutory instruments. Indeed, the reliability of transmission lines has improved since the commencement of the NEM. This is illustrated by the trendline in Figure 1 which shows the decreasing amount of energy not supplied by transmission in the NEM averaged across the jurisdictions.

[1] Firecone Ventures, *Regulatory Framework for Transmission – Final Report*, November 2003 p.ii
[2] Based on the depreciated optimised replacement cost (DORC) value of transmission assets which came under ACCC regulation in 1999.

Figure 1: Average of system energy not supplied due to faults or outages[3]



There are also measures in place to further improve the quality of the service provided by TNSPs. Service incentive schemes are now included as part of TNSPs' revenue caps. These schemes allow TNSPs to receive +/–1 per cent of their MAR for over or under performance. In the last two years of reported performance against service standard targets, all of the major five TNSPs have outperformed all of their targets.

Notwithstanding this performance, there has been some industry concern about the market impact of transmission outages and claims that TNSPs should be subject to greater penalties for lower performance.

New work undertaken by the AER - the indicators of the market impact of transmission congestion (MITC) and accompanying report for 2003-04 - reveals there is great potential for data to reveal the impact of transmission network congestion on electricity prices. The potential impact of transmission congestion has been a key issue since the commencement of the NEM.

With the assistance of NEMMCO the AER has developed a number of indicators to measure this impact. The indicators show total congestion costs in the NEM of $36 million in 2003-04. Given the turnover in the electricity market for the same period was $6 billion this would indicate that the cost of congestion is relatively low.

This data should be treated cautiously as it only outlines results for a single year. Longer term trends are expected to be revealed in the MITC data for the 2004-06 period which will be issued later this year. However, these preliminary investment and performance outcomes indicate that the transmission sector is generally responding well to the needs of the market and that the regulatory framework is supporting necessary transmission investment.

[3] Energy Supply Association of Australia, *Electricity Gas Australia 2005*, p. 30

This data will help industry, planning bodies, policy makers and the AER understand the economic costs of transmission congestion and to identify locations requiring transmission investment. Market incentives have a great potential to strengthen the regulatory framework and reveal if there is effective investment in and operation of transmission networks.

Framework for transmission investment

As noted in the Issues Paper, the two main elements of the regulatory regime for transmission investment in the NEM are the economic regulation of revenues and the planning obligations on TNSPs. The economic regulation of TNSPs entails a revenue cap determination which approves an allowance for capital expenditure for the forthcoming regulatory period. This revenue cap is determined using a risk adjusted weighted average cost of capital, the TNSPs asset base and forecast capital works program and efficient operating costs. The economic regulatory process works in parallel with the investment planning undertaken by TNSPs for future network augmentation. As opposed to replacement of lines, a network augmentation increases capacity or provides a new service. The identification of required network augmentation is influenced largely by the reliability requirements of each jurisdiction.

Figure 2: Economic regulatory regime for transmission investment

<u>Economic regulation of capital expenditure</u>

TNSP conducts network planning and prepares revenue application

↓

AER assesses proposed capex—examines efficiency of cost estimates and the drivers behind new projects (taking into account any projects that have passed the regulatory test)

↓

AER sets revenue cap and determines total ex-ante capex allowance

↓

TNSP constructs capital projects

↓

All actual expenditure is rolled into regulated asset base at next revenue reset without ex-post assessment

In relation to economic regulation, the AER has adopted a clear approach to how it will assess revenue proposals and make allowance for efficient transmission investment.[4] The AER follows the approach established in its *Statement of*

[4] However, the AER notes that the AEMC is currently reviewing chapter 6 of the Rules which governs the economic regulation of transmission and that the current regulatory framework may be subject to amendment. The comments contained in this submission should therefore be read in light of this review.

Regulatory Principles. A feature of the regulatory approach is the provision of capital expenditure allowance on an ex ante basis.[5] The ex ante approach allows a TNSP the freedom to expend its capex allowance on the suite of projects it deems appropriate with the knowledge that all actual expenditure will be rolled into the regulated asset base without the uncertainty of ex post assessment. The certainty and flexibility of the ex ante approach, together with service standards incentives, provide real incentives for efficient investment in transmission. Figure 2 illustrates the broad process in determining a TNSP's capital expenditure allowance in the ex ante approach.

A key element of the regulatory framework for investment is the planning obligations on TNSPs which includes meeting reliability requirements within their jurisdictions. All TNSPs are required to publish Annual Planning Reports (APR) and ensure that their services satisfy fairly strict performance standards. The standards are a combination of reliability standards set by NEMMCO and security of supply requirements set in each of the jurisdictions.

The other major planning obligation is to undertake a regulatory test assessment of proposed network augmentations. The regulatory test is applied by network businesses and is used in the planning phase to evaluate proposed new transmission investment against other network or non-network alternatives to ensure that the investment is at least cost and is competitively neutral.

A regulatory test assessment is required for network augmentations valued over $1 million (small augmentations) with a public consultation process required for regulatory test assessments of investments valued over $10 million (large augmentations). The obligation on network service providers is to apply the regulatory test to new network assets. There is no requirement that replacement or refurbishment expenditure be assessed against the criteria set out in the regulatory test.

An investment may satisfy the regulatory test via one of two limbs:

- *The reliability limb* – used for considering reliability driven augmentations, which are based on the service obligations imposed on network service providers through the Rules or state regulations or statutory instruments. A reliability augmentation satisfies the test if it represents the least cost option considering the total costs of the options to those who produce, distribute and consume electricity in the NEM.

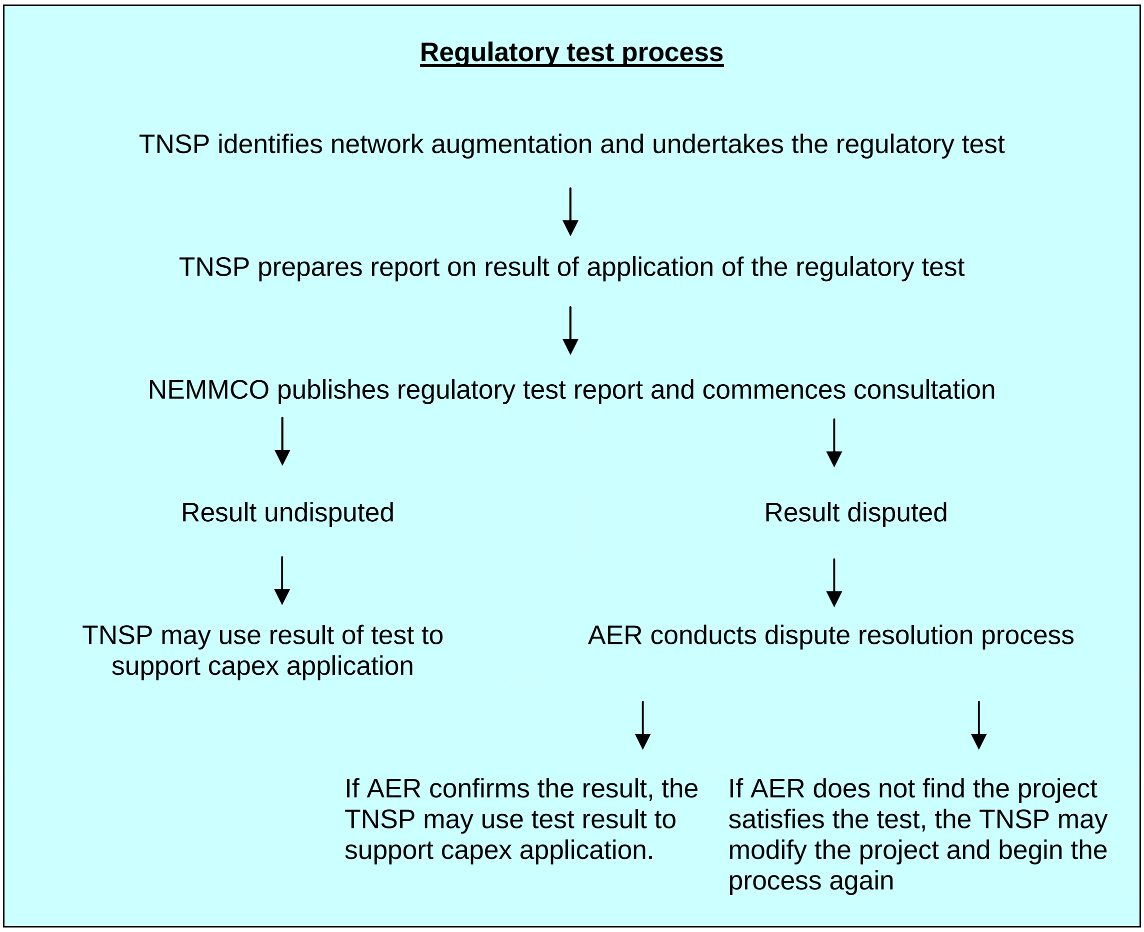
- *The market benefits limb* – applied to non-reliability driven investment. New investment satisfies the market benefits limb of the regulatory test if it maximises the net present value (NPV) of the market benefits having regard to alternative options, timing and market development.

Clause 5.6 of the Rules outlines the process by which network service providers are to assess the planning and development of networks. The regulatory test is applied by

[5] There is also provision for contingent projects, determined at the revenue reset stage which may be included in the capex program if triggered by specific predetermined drivers or circumstances.

'the proponent' (the TNSP proposing the investment) who must provide a report detailing how the investment satisfies the test. Following a consultation process, the proponent's report is then published on the NEMMCO website. The broad process for regulatory test assessments for large network augmentations which are eventually included in a TNSP's capex program is illustrated in Figure 3.

Figure 3: Regulatory test process for large network augmentations



The role of the regulatory test

The questions posed in the Issues Paper indicate that ERIG is undertaking a broad consideration of regulatory test issues. The AEMC is considering similar issues in its review of the MCE's regulatory test principles Rule change proposal. It is therefore important for ERIG to liaise with the AEMC on regulatory test issues.

The Issues Paper includes a number of questions concerning the operation of the regulatory test, in particular questioning the role of the regulatory test.

The ACCC/AER believes that the overarching role of the regulatory test is to minimise inefficient investment in the NEM. Further, the test is directly related to ensuring a level playing field is established between the competitive elements of the market and the transmission sector as a regulated monopoly. This intent was clear in the development of the regulatory test, where the clear aim was to protect new generation investment from over-building by TNSPs (which would favour more remotely located generators). Since transmission is (in some cases) a substitute for remote generation, certain generation investment is exposed to the risk of transmission network expansion. In order for there to be adequate efficient private commercial generation investment, it is necessary to limit or prevent the possibility of non-commercial or inefficient transmission investment decisions. This is reflected, in the original Ernst and Young report of March 1999, which was used to develop the initial regulatory test, which states:

> Our main concern, therefore, is to ensure that the regulated transmission investment decision criterion does not unfairly favour one group of generators over another. For example, if the decision criterion promoted investment to relieve all transmission constraints, then existing (and new entrant) generators located remotely from load centres could be said to be favoured over potential new entrants close to load centres. We take "favouring" (or discrimination) to mean any arrangement, not reasonably based on cost, which allows one party to benefit over another. With reference to the example above, regulated transmission could be deemed to favour remote generators if the cost of that transmission together with the cost of remote generators exceeded the cost of generators close to load centres.[6]

Therefore, the regulatory test attempts to limit or prevent the possibility of non-commercial or inefficient transmission investment decisions in order to ensure efficient development of commercial generation investment together with the efficient development of transmission. This will best promote the long term interests of customers as required by the NEM objective.

Further, in the context of an ex ante framework, the regulatory test plays two important roles in fulfilling this overarching efficiency objective. First, the regulatory test provides a valuable consultative and transparency tool for transmission planning. The regulatory test is crucial to an effective transmission planning process in that it allows for public consultation and comment whilst strengthening the transparency and rigour of transmission planning and investment decisions. The fact that a TNSP's application of the regulatory test can be disputed provides a further check on inefficient investment.

Secondly, the regulatory test provides information to assist in regulatory decision making at the TNSP's revenue reset. In the context of the current ex ante regulatory framework, the regulatory test plays a significant role in informing the regulator about the merits of proposed capex projects and the efficiency of the proposed capital expenditure, particularly for projects scheduled early in the regulatory period. As the ex ante approach means that there will be no ex post assessment of projects, it is important that the regulator obtains relevant information at the time it sets the revenue cap to ensure the capex allowance is determined appropriately.

It is important to clarify that the regulatory test is not a defined part of the economic regulatory process, but part of the planning process. Whilst the AER promulgates the test, the AER is not responsible for transmission planning. Passing the test satisfies planning and consultation requirements, and informs the regulatory decision.

[6] Ernst and Young, *Review of the Assessment Criterion for New Interconnectors and Network Augmentation*, March 1999, p. 17

Concerns with the regulatory test

There have been concerns raised that the regulatory test is acting as a barrier to appropriate transmission investment. The problems associated with the development of the South Australia - New South Wales Interconnector (SNI) in particular are used to argue that the regulatory test is a major impediment to necessary transmission development in the NEM. It should be recognised that SNI was assessed under a fundamentally different transmission development framework to what exists now.

Basically, the framework for transmission development has progressed through four distinct stages:

- *Pre-NEM - the customer benefits test*: this test was applied by NEMMCO and the Inter-Regional Planning Committee (IRPC)[7] to transmission augmentations between regions, and by transmission businesses to assess transmission developments within regions. The customer benefits test was specified in the National Electricity Code (Code).

  The customer benefits test was applied by NEMMCO to the proposed SNI project. SNI failed to satisfy the customer benefits test because conflicting assessment criteria created issues in its application.

- *December 1999 – the regulatory test*: In light of problems with the customer benefits test, the ACCC was requested, as an independent party, to review the test. The ACCC revised the customer benefits test to the regulatory test. These changes were supported by industry.

  NEMMCO and the IRPC continued to apply the regulatory test to transmission developments between regions. NEMMCO assessed a 400MW upgrade to the interconnector between Snowy and Victoria, which was approved under the regulatory test – allowing its timely development.

  At the same time, SNI was assessed against the regulatory test. There was significant contention surrounding SNI given that at that time, Murraylink, a non-regulated link, was built covering the same area as SNI. NEMMCO concluded that SNI was justified under the regulatory test. In December 2001, this decision was challenged in the National Electricity Tribunal (Tribunal) by Murraylink but failed. In July 2003, the Victorian Supreme Court allowed Murraylink's appeal and set aside the Tribunal's decision on the basis of an error of law by the Tribunal.

- *Regulatory test and regulatory test process change*: Soon after the issues with the SNI process, NECA revised the process for the consideration of transmission development through a code change package known as the Network and Distributed Resources (NDR) Code changes. These Code changes were authorised by the ACCC in February 2002. These Code changes devolved responsibility for new investment to the TNSPs and replaced the inter/intra regional distinction with a new large/ new small network asset distinction. The package also inserted reference to a reliability augmentation and introduced a dispute resolution process for regulatory test applications. The revised arrangements reflected movement towards decentralised transmission development decision-making.

- *August 2004 – Review of the regulatory test*: the ACCC reviewed and revised the regulatory test to provide further clarity and explain the consideration of competition benefits in the market benefits limb of the test. Projects coming under the market benefits limb must achieve a net market benefit in most credible scenarios, and some of these development scenarios may include competition benefits. Competition benefits are defined as the benefits accruing to the market as a result of changed generation bidding. The calculation of these benefits does not include wealth transfers which see benefits move from one party to another. These are not considered under the regulatory test as it is concerned with the overall increase in total market benefits.

In this review, the ACCC/AER encourages ERIG to consider the effectiveness of the operation of the current regulatory test, and not previous versions. As highlighted above, the regulatory test is now applied by TNSPs and explicitly includes the consideration of competition benefits. In addition, the AEMC recently approved a set of Rule changes to further streamline the regulatory test dispute resolution process.

Despite this, it appears many comments about the flaws in the regulatory test appear to be referring to a centralised framework for assessing transmission investment that is no longer in place. Further, market network service providers are unlikely to be a significant feature in the market moving forward (meaning that there won't be 'competition' between regulated and non-regulated entities to build transmission assets covering the same area as there was in the case of SNI).

It should be noted that the revised regulatory test has been supported by industry and the Ministerial Council on Energy. There may, however, be opportunities to improve the application of the regulatory test. The process of developing an interconnector relies on the co-ordination of investment decisions between two TNSPs. There would appear to be the prospect of an inefficient outcome if the interests of the TNSPs are not aligned.

Further, given the importance of the regulatory test it needs to be well understood by stakeholders. There is a need to enhance the replicability of the regulatory test and help ensure its consistent application. As part of the MCE’s regulatory test principles Rule change proposal, the AEMC is considering whether to insert a provision into the Rules requiring the AER to issue guidelines on the application of the test. It is envisaged that these guidelines would provide some instruction on the methodologies for estimating competition benefits. This should ensure an improved understanding of the regulatory test and its application across the market. However the AER notes that the quantification of market benefits is not an exact science and that there are a number of approaches that could be used. Whilst AER guidelines will assist in putting some definition to the methodology to be employed in undertaking a markets benefits assessment they will not eliminate the inherent difficulties in applying the test entirely.

A further step in enhancing the clarity and certainty of the regulatory test is the development of a clear definition of a reliability augmentation for the reliability limb. The IRPC has requested that the AEMC remove the provision in the Rules which requires the IRPC to provide a set of criteria for the definition of a reliability augmentation.[8] Given that the majority of projects are assessed under the reliability limb, it is important to have a clear definition of a reliability augmentation for market transparency and certainty. This will assist the AER in performing its role as the dispute resolution body for the regulatory test. This issue is a difficult one and is tied to the challenges in achieving consistent transmission reliability requirements across the jurisdictions.

Transmission planning

A real challenge in progressing a more national transmission grid lies in implementing a more effective and coordinated transmission planning regime.

There are currently several different models for transmission planning across the NEM jurisdictions. Pursuant to the Rules, each jurisdiction has a body responsible for transmission planning which determines how networks are to be augmented to meet that jurisdiction's security of supply standards. In NSW and Queensland, this responsibility is vested in TransGrid and Powerlink respectively. In Victoria the not-for-profit entity VENCorp has sole responsibility for planning and directing investment decisions and in South Australia, the planning functions are the responsibility of the Electricity Supply Industry Planning Council (ESIPC), a statutory authority. In Tasmania, the jurisdictional regulator has established the Reliability and Network Planning Panel which has roles and responsibilities similar to that of ESIPC, without actually having any responsibilities under the Rules.

There is concern that this jurisdiction-by-jurisdiction planning approach may ignore the NEM-wide benefits of transmission.[9] The Annual National Transmission Statement (ANTS) was developed to provide a more national focus to transmission planning. It aims to provide the market with an integrated overview of the possible required future development of major national transmission flow paths in the NEM. In addition, the MCE has lodged a proposal to create a Last Resort Planning Power (LRPP), whereby the AEMC will have a power to direct a relevant party to undertake the regulatory test for transmission investment. This Rule change proposal is currently being considered by the AEMC. However, a potential weakness of both of these measures is that they stop short of the ability to direct the construction of network investment and deliver tangible outcomes. Further, the ANTS only assesses opportunities at a high level- it does not involve detailed planning or utilise the regulatory test. As highlighted previously there is an additional challenge in coordinating investment decisions in situations where two TNSPs are involved. There are a number of measures and reforms which may help the market progress towards a more national transmission grid with a NEM-wide focus.

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[8] IRPC, *Submission to AEMC – Regulatory Test Principles Rule Change*, February 2006

[9] See for example, Council of Australian Governments Energy Market Review (2002), *Towards a truly national and efficient energy market*, Final Report, December 2002, pp 125-126

Reliability standards

A practical step to address the above issues which does not involve institutional or structural change is to establish more consistent reliability standards across all the NEM-states to promote consistency in transmission planning decisions. The different jurisdictional security of supply requirements could be refined to form one uniform security of supply standard to be interpreted in a clear and consistent fashion by all the TNSPs. If required, this could allow derogations to meet local load requirements (for example, separate standards for CBD areas).

Currently schedule 5.1 of the Rules sets out the minimum reliability requirements of transmission networks in the NEM. Schedule 5.1 requires TNSPs to plan to ensure their responsibilities under a connection agreement are satisfied, even in cases of certain faults (credible contingency events) occurring.[10] As TNSPs are free to negotiate connection agreements that require them to deliver higher standards of reliability than the minimum, TNSPs may plan to a higher standard of reliability in certain situations.

A further layer of jurisdictional security of supply standards operates on top of schedule 5.1 which results in divergent planning methodologies. The diverse arrangements result in different degrees of discretion afforded to TNSPs in relation to the setting of these standards. In South Australia for example, these standards are prescribed in great detail through the *Electricity Transmission Code*, whilst in NSW and Queensland TNSPs are conferred some discretion in the interpretation of the requirements of these standards through their transmission licenses. The approach adopted by Victoria and Tasmania is a probabilistic planning standard which contrasts with the deterministic approach utilised in the other jurisdictions. Table 1 illustrates the diversity of approaches adopted in the jurisdictions in the setting of security of supply standards.

[10] Schedule 5.1.2.1 of the Rules: credible contingency events

Table 1: Security of supply standards

State	Planning Body	Security of Supply Standards
VIC	VENCorp	Probabilistic approach based on minimum unserved energy.
SA	Electricity Supply Industry Planning Council	Prescriptive standard specified in clause 2.2.2 of the Electricity Transmission Code (SA) which ranges from N–0 through to N–2 depending on the category and location of the line.
TAS	Transend	Defaults to a probabilistic approach based on minimum unserved energy.
QLD	Powerlink	Requirements are specified in Powerlink's transmission authority (transmission license) which Powerlink interprets as deterministic (N¬1[11] or N–1–G[12]) unless otherwise agreed.
NSW	TransGrid	Section 6 of the *Electricity Supply (Safety and Network Management) Regulation 2002* (NSW) allows the Director-General of the NSW Ministry of Energy & Utilities to require network service providers to lodge 'network management plans' which include security of supply standards interpreted by TransGrid as deterministic (N–1).

A clear and transparent security of supply standard framework across the NEM would benefit all stakeholders in boosting the consistency of transmission planning decisions. Progress towards a national standard should form part of the considerations of the Reliability Panel in its current review of reliability standards in the NEM. This would continue the work commenced by NECA in 2000 which aimed to reach a more national standard to facilitate the integrated operation of the energy spot market and network investment and reliability.[13]

The ACCC/AER recognises that the jurisdictional standards of reliability are a policy matter for the States. However, as schedule 5.1 and the jurisdictional requirements are open to interpretation and individual connection agreements are not open to scrutiny, it is currently difficult to understand the underlying rationale behind some reliability settings. As a consequence, certain standards may appear arbitrary and unjustified. The Reliability Panel's review should cover both state-based and rule-based reliability obligations. The review should examine ways to develop a consistent and transparent framework for specifying state-specific reliability obligations and their rationale, such as the formulation of an appropriate reference level of reliability to be provided in transmission networks at certain connection points, and the expression of this as a benchmark standard. If required, local deviations could be allowed to meet specific requirements based on the application of a consistent and transparent methodology.

[11] N-1 refers to the planning standard that provides for the transmission system to continue to supply contracted loads connected to the system without interruption should any one element fail (typically an outage of a transmission line or transformer). N-1 capacity may be provided by whatever means including by implementation of transmission network capability and/or network support arrangements.
[12] N-1-G plans on an N-1 basis but also provides for continued service where the most critical or largest generator is out of service coincident with a network element outage.
[13] National Electricity Code Administrator (NECA) Reliability Panel, *Review of network performance standards- Issues paper*, September 2000, p. 1

Institutional arrangements

There may be reticence from jurisdictions to move away from the transmission planning model that they currently operate under. There are a number of different transmission planning options, all of which have pros and cons. Table 2 sets out some of the pros and cons of the several identified options which deal with institutional arrangements.

Table 2: Options for Institutional Planning Arrangements

Option	**Argument For**	**Argument Against**
Current decentralised system where TNSP is responsible for planning	▪ Minimises regulatory burden and cost. ▪ Arrangements are understood. ▪ Maximises local knowledge.	▪ Potential lack of alignment between TNSPs in planning for inter-regional benefits ▪ Incentives for TNSPs to plan for inter-regional transmission is not always strong ▪ Weak incentives on TNSPs to consider non-network solutions.
Reviewing body to conduct independent regulatory test of certain projects	▪ Ensures appropriate consideration of non-network solutions. ▪ Builds upon well understood framework. ▪ Provides assurance that projects have fairly passed the Regulatory Test.[14]	▪ Possibility of disputes over costings between independent body and TNSP. ▪ Does not guarantee investment outcome.
National independent planner for main transmission backbone without power to direct investment	▪ Ensures appropriate consideration of non-network solutions. ▪ Allows market wide benefits to be considered and captured.	▪ Costs of implementation. ▪ Does not guarantee an outcome. ▪ Less consistent with light handed incentive based regulation.
National independent planner for main transmission backbone with power to direct investment	▪ Guarantees an outcome. ▪ Benefits of competitive tendering process for projects. ▪ Allows market wide benefits to be considered and captured. ▪ Ensures more national approach to transmission planning and investment.	▪ Issues over accountability of planning body ▪ Costs of implementation. ▪ May raise sovereign risk issues for some entities as investment decisions are taken away. ▪ Less consistent with light handed incentive based regulation.
National independent planner for all transmission with	▪ Guarantees an outcome. ▪ Benefits of competitive	▪ Centralised planning may be inefficient for local

[14] This body may also act as an expert custodian and adviser to the AER on regulatory test guidelines.

power to direct investment	tendering process for projects. ▪ Allows market wide benefits to be considered and captured. ▪ Ensures more national approach to transmission planning and investment	transmission needs ▪ Costs of implementation. ▪ May raise sovereign risk issues for some entities as investment decisions are taken away. ▪ Less consistent with light handed incentive based regulation.
Establish National Grid Company	▪ Guarantees an outcome ▪ Ensures national approach to transmission planning and investment. ▪ Ensures coordinated transmission operations. ▪ Consistent with light handed incentive-based regulation	▪ Large commercial and sovereign risk issues. ▪ Unclear benefits over less intrusive/heavy handed options. ▪ Removes ability to compare efficiency of transmission business operations and develop benchmarks

Given the inherent difficulties in implementing a single preferred transmission planning model, ERIG could consider a number of options (in addition to the reliability standards issues already raised) to improve the national character of transmission planning which do not involve significant institutional change.

For options involving the continuation of TNSP-driven planning, it would be beneficial for the NEM-states to conduct a review of state legislation to ascertain whether there are clear obligations on TNSPs to plan for the benefit of all consumers in the NEM (consistent with the NEM Objective) not just simply the customers in their jurisdiction. If none exist, jurisdictional obligations may need to be created, and any existing jurisdictional obligations conflicting with whole-of-network planning requirements removed. This could support mandated coordination obligations on TNSPs. It would assist if other incentives were provided for TNSPs to invest in transmission network even in cases where it benefits another region. Exactly how this could be achieved is a question for ERIG to consider.

A further option is to adopt a “bottom up” approach to the consolidation of transmission planning involving an amalgamation of state planning bodies for those states that choose to participate. For example, Victoria, South Australia and Tasmania already have independent transmission planning bodies so it may be practical for them to amalgamate or strengthen the coordination between their bodies.

Electricity Market Structures

- How are competition and efficiency affected, now and into the future, by:
  - integration between monopoly and contestable sectors;
  - vertical integration between contestable sectors; and
  - horizontal aggregation (greater market concentration)?
- What, if any, are the limitations of section 50 of the TPA in providing adequate protection against energy sector mergers which may lessen competition substantially?
- Are these limitations generally applicable, or especially relevant, where contestable and non-contestable markets are combined?
- Is the energy market sufficiently different to warrant special rules beyond those generally applicable? If so, how?

From the mid-1990s State governments in conjunction with the Commonwealth Government implemented wide ranging structural reforms in the electricity supply industry. In each jurisdiction these reforms vertically separated contestable generation and retail activities from natural monopoly network elements (although in many states combined distribution-retail businesses were created). The reforms also involved creating competing companies at generation and retail levels.

Since the reforms were implemented, there has been some horizontal integration of generators, retailers and network businesses. There has also been significant vertical integration of generators and retailers, and proposals to vertically merge generation and transmission functions.

Each reaggregation proposal has been considered by the ACCC under section 50 of the TPA. The ACCC/AER has the following comments to make on the capacity of section 50 to adequately consider the competitive effects of various merger proposals.

Generation-transmission mergers

The ACCC has previously raised considerable concerns about mergers between generators and transmission companies. When the owner of essential infrastructure also participates in a contestable market it typically has the ability and the economic incentive to restrict the level of competition in the contestable market in ways that are difficult to prevent or monitor.

Effective structural separation of the operation and control of the transmission sector from generation is an important issue in the NEM. When the owner of essential transmission infrastructure also participates in the contestable generation market it typically has the ability and the economic incentive to discriminate against rivals in this market. There are numerous possible methods to effect that discrimination. In some cases these are subtle, and therefore may be difficult to detect. Discrimination could occur through limiting or raising the price of access to monopoly services to competitors by:

- imposing terms for access (restricting access to the transmission network by delaying or degrading connections)

- investment and maintenance decisions (restricting the quantity and quality of the transmission service provided or pursuing improvements in the network performance for its affiliated interests)

- sharing commercially sensitive information regarding competing generators with its affiliated generator or retailer

- line rating decisions and

- negotiation and processing of connection agreements.

This potential for discrimination highlights the need to retain effective separation between generation and transmission activities. A number of the concerns highlighted above relate to discrimination in terms of access. These problems of a 'regulatory evasion' nature, which are consequent on the existence of information asymmetries, are unlikely to be fully captured in the substantial lessening of competition test in section 50.[15]

The ACCC has previously supported the introduction of specific provisions aimed at limiting the level of cross ownership of generation and transmission as means of dealing with this problem. At present the MCE is developing such cross ownership restrictions. The ACCC/AER supports the development of these cross ownership provisions as an effective complement to section 50 of the TPA.

Generation-retail mergers

ERIG is interested in understanding how competition and efficiency are affected, now and into the future, by vertical integration between generators and retailers.

The original design of the NEM was based on structural separation of generators from retailers. The stated objectives of the fully competitive national market included "the ability for customers to choose which supplier, including generators, retailers and traders, they will trade with" and "no discriminatory legislative or regulatory barriers to entry for new participants in generation or retail supply."[16] While there was no explicit stated national policy requiring vertical separation, in each NEM jurisdiction vertical separation was adopted. In some jurisdictions, this followed an examination of the most appropriate models, specifically, South Australia and Tasmania.[17] In Victoria cross ownership regulations were imposed limiting subsequent reintegration between retailers and generators.

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[15] The ACCC/AER acknowledges that section 50 did successfully deal with a recent potential generation-transmission merger, SPI/TXU. However, the ability of section 50 to deal with generation-transmission mergers has not been tested in court and would depend on the court accepting that regulation of transmission is imperfect so that market manipulation cannot be ruled out.
[16] *COAG Communiqué,* Darwin 19 August 1994, Attachment 2(b)
[17] See National Competition Council, *Assessment of governments' progress in implementing the National Competition Policy and related reforms,* June 1999.

The ACCC/AER's understanding is that establishment of separate retail and generation businesses in all jurisdictions in the early to mid-1990s was a practical necessity given the historically high level of integration between distribution and retail.

However, some policy makers at the time also considered that the competitive model should recognise two distinct competitive markets: a wholesale market where generators competed against each other and a retail market where "retailers compete against each other to supply contestable customers."[18] The ACCC/AER understand that in this view active hedging markets would be required to manage spot market activities, with contracts written around the volatile energy only spot market. This model was designed to encourage the liquidity of the contract markets and establish an open market to enable retailers and generators to manage their risks. Structural separation between generation and retailing was also seen to help minimise barriers to entry of retailers and generators, consistent with COAG, and in turn encourage strong competition particularly in the retail markets.

Since then significant vertical integration has occurred. AGL purchased a 35% stake in Loy Yang A in April 2004, and CLP purchased SP Energy's retail and generation assets in mid 2005. Now two of the three dominant retailers in the Victorian and South Australian markets are substantially integrated (AGL and TRU). The third major retailer also has peaking plant and has announced plans to build base load plant in Victoria.

In the majority of mergers to date involving generator-retailer integration, the ACCC has assessed the proposed merger against section 50 and concluded that the merger is unlikely to involve a substantial lessening of competition and therefore has allowed the merger to proceed. While the ACCC will assess any future integration on a case by case basis, the majority of future proposals that only involve generator-retailer integration are also unlikely to involve a substantial lessening of competition under section 50.

Vertical integration between generation and retailing reduces the need for explicit arms-length hedging as the integrated "gentailer" has a natural or internal hedge through being both a supplier and a buyer of spot electricity. While individual generator – retailer mergers are unlikely to involve a substantial lessening of competition, the overall result of this trend could be a reduction in the liquidity of the hedge market and, as a result, a reduction in the availability of hedge contracts.

There are a number of possible costs and benefits to the change. On the positive side the benefits include:

- Improved risk management. Integration can be used by retailers to mitigate the risks associated with generator market power by providing a natural hedge against spot market volatility. Generators with market power only have an incentive to manipulate the spot price to the degree that they have unhedged load that will be dispatched at the higher spot price. A generator with a natural hedge due to

[18] Victorian Department of Treasury and Finance, *Victoria's Electricity Supply Industry: Towards 2000* June 1997, p 3

vertical integration has less incentive to manipulate the spot price because any price increase that benefits the generator is at least partially offset by the detriment the price rise causes to its retail arm.

- Reduced transaction/risk costs. Integration may reduce trading costs and costs associated with trading risks, for example, credit risk costs.

- Significant generation investment. Most of new peaking plant in Victoria and South Australia has been built by the large retailers.

Costs may also arise if there is a significant loss of liquidity in hedge markets as integrated retailers hedge risks internally. More specifically:

- Entry barriers – retail. Barriers to entry for stand alone electricity retailers increase if it becomes more difficult for them to secure competitively priced contracts. This risk is most obvious where all/most generation is owned by competing retailers as is the case in New Zealand.

- Entry barriers – generation. If the integrated retailers build their own generation plant there may be little scope for new generation entry.

- Risk management for small integrated retailers. All retailer-generators must manage risks such as generator outages. Large retail - generators can more readily manage these risks through internal back up due to "portfolio" effects; whereas small generator-retailers are likely to be more reliant on external hedging. Accordingly smaller integrated players are likely to be more disadvantaged if there is a lack of liquidity in hedging markets.

Market outcomes so far have been broadly favourable, both before and after the move towards integration. Prices for industrial users have fallen significantly and have been stable for household users except in South Australia. At the same time the market has delivered significant new investment. The favourable outcomes have been due to a number of factors including the generally successful implementation of the competitive reforms, low and stable fuel costs, increases in productivity and limited exercise of sustained market power.

The trend towards greater integration of retailers and generators seems likely to continue as businesses act to ensure they are not disadvantaged in their ability to buy/sell electricity and manage risk compared to other generator-retailers. Section 50 is unlikely to prevent further integration.

The ACCC/AER encourages ERIG to evaluate the risks associated with the trend towards vertical integration, to weigh up the costs and benefits associated with different policy options (including the status quo) and to consider whether a policy response is warranted.

In undertaking a cost/benefit analysis it would be useful to clearly identify policy objectives. This will help ensure that the benefits of any policy response are clearly defined.

A useful starting point is the objective of competitive markets because of the economic efficiency benefits they generate. The initial structural reforms and supporting legislation and rules were largely directed at achieving this objective. The question now is whether the initial policy settings are appropriate or whether adjustments are required.

Horizontal mergers

The ACCC has previously considered a number of horizontal retail mergers under section 50 of the TPA. Based on this experience, the ACCC is of the view that the TPA adequately covers consideration of competition factors associated with horizontal retail electricity mergers such as market power and market definition. Therefore, the ACCC believes that horizontal retail mergers do not need to be covered by industry specific cross-ownership rules.

The ACCC has also considered a number of horizontal generation mergers under section 50 of the TPA. To date, the ACCC considers that the TPA has generally been effective in the consideration of competition issues associated with these horizontal electricity generation mergers. However, the ACCC notes that in the *AGL v ACCC* case, French J defined a NEM wide market for generation.[19] The Court did not agree that markets for generation were state-based and thus it has been argued that this decision potentially gives greater scope for generators to merge 'without gaining' market power. The ACCC/AER notes, however, that the findings of French J have not been tested in the context of a significant generation merger. While the ACCC has recognised French J's decision in subsequent merger proposals considered since the AGL – Loy Yang case, the ACCC has stated that, in its opinion, a different market was relevant.[20]

As noted above, the ACCC/AER believes that the major trend in electricity market structure is towards greater integration of generation and retail activities. An issue that may have to be considered in the future concerns the horizontal aggregation of generator-retailers. Such a merger would appear to raise more acute competition issues than the other horizontal mergers outlined in this section. As it has never been tested, it is not clear how effective section 50 would be in dealing with the merger of competing generator-retailer companies.

- Is competitive neutrality between government and private businesses a significant issue influencing competitive and efficient outcomes?

[19] *Australian Gaslight Company v Australian Competition and Consumer Commission (No. 3)* [2003] FCA 1525 at 387.

[20] See for example, ACCC, *China Light & Power's proposed acquisition of the Australian non-regulated energy assets of Singapore Power – Public Competition Assessment*, 14 April 2005; and ACCC, *ACCC assessment of SP Energy's acquisition of TXU Australia*, 19 July 2004. In these matters, the ACCC considered that the relevant geographic market was the market for the supply of wholesale electricity in Victoria, and also in Victoria and South Australia combined.

The ACCC/AER notes that previous energy market reviews have raised issues about the impacts of government ownership, particularly of generation capacity, on the competitiveness and efficiency of Australia's electricity markets.[21] In noting these issues, the Parer Review argued that "governments that currently own generation assets should pursue a program of divestment, with a view to completely exiting the market, or at least reducing ownership to a single generator."[22]

However, the ACCC/AER considers that government ownership, particularly of generation, is likely to remain a significant feature of the market for the foreseeable future. In this environment, it appears critical to ensure that there is a level playing field between state-owned and privately-owned businesses. If private businesses perceive that government businesses are not always operating on a commercially driven basis, there will clearly be sovereign risk issues for private investors. Private businesses will be reticent to invest under these conditions. Concerns about government interference in the market are not limited to circumstances where they are an asset owner. Similar issues about a level playing field can arise where governments attempt to "pick winners" and subsidise specific projects or technologies.

There are a number of measures that governments can implement to provide market confidence that investment decisions are being made on a strictly commercial basis.

To date, the focus in Australia has largely been on competitive neutrality arrangements. The concept of competitive neutrality is founded on the principle that competition should be fair between different classes of market participants so that a level playing field exists between competing public and private entities. There has been considerable effort undertaken by COAG over the last ten years in developing and implementing an operational competitive neutrality framework in Australia.[23] The competitive neutrality framework provided by these agreements has been commended internationally.[24] Further, the recent *Competition and Infrastructure Reform Agreement*[25] seeks to enhance reporting and corporate governance requirements which should lead to greater transparency and provide incentives to encourage State-owned businesses to implement competitive neutrality reforms.

ERIG should assess the materiality of competitive neutrality concerns and consider whether Australia's competitive neutrality framework should be further improved in respect of the energy markets. If there is a real need for improvement, a first step would be for governments that own electricity businesses to independently review their shareholding monitoring and decision-making arrangements to determine whether they could be strengthened and to make public their findings. If further

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[21] See for example, Council of Australian Governments Energy Market Review (2002), *Towards a truly national and efficient energy market: Final Report*, December 2002; and Productivity Commission (2005), *Review of national competition policy reforms*, Productivity Commission Inquiry Report, No. 33, 28 February 2005.
[22] Council of Australian Governments Energy Market Review (2002), *Towards a truly national and efficient energy market: Final Report*, December 2002, p. 119.
[23] As established through the *Competition Principles Agreement* (1995) and the *Agreement to Implement the National Competition Policy and Related Reforms* (1998).
[24] Organisation for Economic Co-operation and Development (2005), Competition Committee, *Regulating Market Activities by Public Sector*, DAF/COMP(2004)36, 1 February 2005, pp. 48–50.
[25] *Competition and Infrastructure Reform Agreement*, 10 February 2006 COAG clause 6.1

improvements in the competitive neutrality framework are required then this will require an assessment of existing enforcement mechanisms and possible alternatives in ensuring the compliance of State-owned businesses with their competitive neutrality obligations. Currently, the key element of Australia's competitive neutrality enforcement program is the complaints-handling mechanism which has been implemented in each of the Commonwealth, State and Territory jurisdictions. The ACCC/AER would encourage ERIG to consider whether a complaints mechanism whereby complaints against a government corporation are heard by a body set up by the same jurisdiction would highlight the full extent of competitive neutrality issues.

A number of alternative enforcement mechanisms exist internationally. Although there may be practical difficulties in implementing some of the approaches listed below given Australia's political and legal circumstances, there are nevertheless a number of lessons to be learnt from the international experience. A 2005 OECD report, *Regulating Market Activities by Public Sector,*[26] lists a number of these mechanisms including:

- mechanisms that hold agencies accountable for their compliance with government policies, which could be extended to cover competitive neutrality obligations
- administrative mechanisms which require compliance with competitive neutrality obligations and
- legislation which specifies how government business activities are to be conducted when competing in the private sector.

In relation to the third mechanism, there is Australian precedent. Most notably, the Western Australian Government has capped the generation capacity of Western Generation at 3000MW.[27]

The ACCC/AER encourages ERIG to undertake a broad consideration of these competitive neutrality issues in this review.

[26] See Competition Committee, OECD, *Regulating Market Activities by Public Sector, Proceedings of a Roundtable on Market Activities, June 2004,* DAF/COMP(2004)36. 1 February 2005. The AER is aware that the Commonwealth Government does not have the power to require State Governments to reform their business activities.
[27] Ministerial Direction issued in April 2005. The Ministerial Direction has been replaced since with separate directions on Verve Energy and Synergy, following the disaggregation of Western Power.

Financial markets

▪ Are there structures or rules or mechanisms which impede the development and/or operation of effective financial markets?

It is important to have efficiently operating financial markets to support the operation of electricity and gas markets. As noted in the Issues Paper, efficient financial markets tend to emerge of their own accord in the absence of regulatory or other barriers. Therefore, the focus in the Issues Paper of identifying these impediments to the efficient operation of financial markets is supported. The ACCC/AER believes this focus is appropriate because it is not clear that the materiality of financial markets issues is such that the trading system needs to be radically overhauled, by for example mandating that all electricity is traded through an exchange.

As an initial point, the issues of liquidity in financial markets are heavily related to the market structure questions noted earlier in this submission. In particular, the extent of integration of generation and retail critically determines the overall liquidity of the financial markets. Clearly, an increased trend to a market model based on competition between a number of generator-retailers will compromise the liquidity in financial markets.

There are, however other arrangements in Australia's energy markets that may create impediments to the efficient operation of financial markets. The effects of the Electricity Tariff Equalisation Fund (ETEF)[28] in NSW on the operation of financial markets in particular have been widely analysed on previous occasions.[29]

[28] Currently, all standard retail suppliers and State-owned generators in NSW are required to participate in ETEF. ETEF is designed to manage the wholesale price risk, faced by NSW retailers which are obliged to supply customers at regulated tariffs. It requires standard retail suppliers in NSW to contribute to a fund when the NSW pool price is below the regulated energy component (REC) recovered from regulated tariffs and receive money from the fund when the pool price is above the REC.

[29] National Competition Council, *Assessment of governments' progress in implementing the National Competition Policy and related reforms: Volume one—Overview of the National Competition Policy and related reforms*, 2003, AusInfo, Canberra, p. 7.14. In its 2003 National Competition Policy assessment of NSW, the NCC argued that the operation of the ETEF is likely to reduce the liquidity in the financial and physical hedges market. As ETEF provides standard retailers with a perfect hedge in supplying customers on regulated tariffs, standard retailers and generators have no incentive to contract for supplying this load. The NCC argued that the reduced liquidity may increase the prices of financial instruments and increase the costs for new entrant retailers.