13 May 2011

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear John,

Strategic Priorities for Energy Market Development Discussion Paper

Grid Australia welcomes the opportunity to make a submission in response to the Commission's Strategic Priorities for Energy Market Development Discussion Paper (the Paper) published on 1 April 2011.

Subject to the comments below, Grid Australia considers that the strategic priorities identified by the Commission are generally appropriate. However, Grid Australia does not consider that the third strategic priority should include the efficiency of the transmission economic regulatory framework, given the expectation of an impending Australian Energy Regulator (AER) Rule change proposal on the subject.

A predictable regulatory and market environment for rewarding economically efficient investment

In regard to this priority, Grid Australia submits that the Commission's focus should be on the policy mechanisms needed to secure future adequate levels of generation investment, particularly in relation to base load power. Broadly, the situation in the past where there has been an overhang of generation capacity in Australia has steadily evolved to a tighter balance between supply and demand. However, generation assets are ageing and the current investment environment tentatively emerging from the global financial crisis remains fragile. In particular, it appears significantly affected by uncertainty regarding how best to respond to the challenge posed by climate change.

In addition, there are signs that energy input costs will rise in the medium-term with capital costs likely to respond to the expected increase in world energy demand and fuel costs being influenced by Australia moving to a global gas price. Grid Australia notes the Commission has not nominated a strategic priority in relation to the development of the gas market. However, given these risks, there may be a case for reviewing whether there are ways to improve the competitiveness of gas supply[1].

Taken together, these provide clear signals that the frameworks for ensuring efficient investment in electricity generation capacity should be an important priority. They also raise the related question whether the ways in which energy prices are signalled to customers are as effective as they should be in order to support an appropriate generation mix.

By comparison, the evidence is that the transmission planning and investment framework continues to work well. That framework is the result of a long and careful process of COAG-led industry reform, combining a stable regime with the opportunities for incremental improvement. It ensures that investment is efficient and timely, appropriately takes into account both national and local dimensions and, with the recently enhanced Regulatory Investment Test for Transmission (RIT-T), strikes a pragmatic balance regarding the breadth of the analysis and level of information sharing and consultation required to support specific investments. Recent criticisms of the planning and investment framework by the Garnaut Update Paper No. 8 are misguided and are addressed in the attached copy of Grid Australia's response to that publication.

Finally, there are also processes within the planning framework for ensuring that network service levels are aligned with the expectations of energy consumers. Grid Australia supports the operation of those processes including efforts to make them more transparent.

Building the capacity and capturing the value of demand flexibility

Grid Australia continues to support improvements in the ability of energy users to participate meaningfully in the market. That challenge is complex and part of the solution is to provide network businesses with greater scope to develop innovative solutions that support customer participation. Some of these opportunities were discussed by the Commission in its Review of National Framework for Electricity Distribution Network Planning and Expansion as well as the current Demand Side Participation Review. While much of the value from this sort of innovation will lie within the distribution network sphere, Grid Australia notes that there may be opportunities arising from that work for transmission network service providers to enhance demand side effectiveness.

Ensuring the transmission framework delivers efficient and timely investment

Grid Australia agrees with the view expressed by the Commission in its recent Transmission Frameworks Review (TFR) Directions Paper that it is timely to review a number of aspects of the transmission framework that have implications for the competitiveness of the generation sector (generator access, transmission charging, improving congestion management, supply standards and connection arrangements). In regard to the last of these, Grid Australia is already working with other key stakeholders to examine where there may be scope to improve the processes needed to connect transmission customers.

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1 This will also be relevant in terms of the Commission's input into the Commonwealth Government's development of its energy White Paper.

Grid Australia also notes the commentary in the media regarding recent rises in retail electricity prices. Amongst other things this commentary includes calls to re-examine the economic regulatory regime applicable to both transmission and distribution network businesses.

Grid Australia is concerned that these calls have been made without a full understanding of that framework. There are legitimate reasons why electricity network prices are currently increasing at rates well in excess of general price movements. These include:

- as per generation, the 'overhang' in network capacity from earlier years has been 'used up' and investment in new capacity is required to meet growth in peak demand;
- a move towards 'more conservative' planning standards — notably, recent changes to distribution standards in New South Wales followed a 2004 review[2] of those standards applying in Queensland due to stormy periods in the south-eastern part of that State;
- a 'bow wave' of asset replacement investment is required over the next few years — most network businesses undertook substantial investment in the 1960s and 70s and the assets created during this period are now coming to the end of their economic life;
- the growth in maximum demand has exceeded the growth in energy usage in recent years due to a range of factors, including the increased use of air conditioners — a significant proportion of network investment is required to meet very short periods of peak demand and this capacity is not utilised for most of the time; and
- increases in regulated revenues and, hence, prices reflect real increases in the cost of capital associated with the global financial crisis. The risk adjusted cost of debt increased to record highs during this crisis and remains high in historical terms.

These reasons have been widely acknowledged[3]. In particular, they have been explicitly affirmed by the Chairman of the Australian Energy Regulator (AER) in a letter to the Australian Financial Review this week[4].

Grid Australia understands that the AER is currently reviewing its experience of the economic regulatory framework for network businesses, based on the revenue determinations it has conducted since the implementation of chapter 6 and chapter 6A of the National Electricity Rules. Subsequent to that review, the AER may propose a number of possible improvements or enhancements to the framework via a Rule change to the Commission later this year.

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2 Report on Electricity Distribution and Service Delivery for the 21st Century prepared for the Queensland Government in 2004. The Government's response was published in August 2004 and expressly required the adoption of 'more conservative planning standards'.

3 See, for example, recent transmission revenue determinations by the AER, the Parry-Duffy NSW Electricity Network and Prices Inquiry (Final Report, December 2010) and IPART's Changes in Regulated Retail Electricity Prices from 1 July 2011 (Draft Report, April 2011). For further material regarding claims made by IPART in that draft report, see the attached Energy Networks Association submission.

4 We understand that the Commission has received a copy of this letter dated 11 May 2011.

Grid Australia notes that the Commission, in its TFR Directions Paper, considers the Rule change to be an appropriate mechanism to progress those suggestions. We agree with this approach. There is, therefore, no need to consider this proposed Rule change as part of the Commission's third strategic priority. Rather, the Rule change assessment should be informed by work undertaken in relation to the strategic priorities including the TFR.

Grid Australia looks forward to participating further in the Strategic Priorities Review. Should you have any questions in relation to this submission, please contact me on (08) 8404 7983.

Yours sincerely,

Rainer Korte

Rainer Korte
Chairman
Grid Australia Regulatory Managers Group

grid australia
BACKBONE OF THE NEM

20 April 2011

Professor Ross Garnaut AO
c/- Garnaut Climate Change Review – Update 2011
GPO Box 854
Canberra ACT 2601

Via email: garnautreview@climatechange.gov.au

Dear Professor Garnaut,

Garnaut Climate Change Review – Update Paper 8 *Transforming the electricity sector*

Grid Australia welcomes the opportunity to respond to your Climate Change Review Update Paper 8 *Transforming the electricity sector*.

Grid Australia represents the owners of the main electricity transmission networks across southern and eastern Australia (which is the region covered by the National Electricity Market, or NEM) and Western Australia. Collectively, our members own and operate more than 47,000 km of transmission lines with a combined value of $12 billion, and with a responsibility for funding and delivering an annual investment program of approximately $2.2 billion.

Grid Australia understands the considerable challenges of finding mechanisms that can deliver meaningful carbon signals to businesses and households while ensuring that Australia's power industry remains both sustainable and efficient. Grid Australia supports this objective, but it is a complex problem that tempts easy solutions.

A clear target for the Electricity Update Paper is the current regulatory framework that applies to energy networks. It is asserted that the current arrangements encourage inefficient network investment and cause unnecessarily high electricity prices. However these assertions are not supported by an understanding of the robust economic regulatory framework that operates in the NEM and the principles behind it.

In this regard, it is worth noting that there are very significant differences between transmission networks and distribution networks in relation to their impacts on the NEM and in terms of contribution to the delivered price of electricity. Transmission networks, in addition to being pivotal to reliable supply, play a facilitative role in the NEM by enabling wholesale trading and facilitating the transition to a lower emission generation mix.

In terms of price impact, the transmission component represents less than 10% of the typical electricity bill (compared with about 40% for distribution). The import of these differences is that 'strangling' transmission investment will have a miniscule direct impact on the total electricity bill, but would lead to increases in congestion. Presently, the costs of congestion remain a very small percentage of the value of wholesale energy traded in the NEM. However, the consequential increases in congestion from 'strangling' transmission investment will lead to higher wholesale energy prices, with an impact on electricity bills that would far outweigh the miniscule direct reductions in the transmission charges.

Grid Australia supports enhancements to the NEM that have been built upon COAG's more than decade long program of industry reform (with many elements focussed on the transmission sector), a program that has made the NEM one of the world's most efficient, competitive and reliable power systems.

Given the success of the framework to date, where the broader objectives of government cannot be met through prices or decisions that are efficient within the context of the electricity sector alone, Grid Australia also supports the introduction of measures that operate alongside the NEM framework.

What is essential is that such measures complement, but do not distort the framework, given that doing so would impair the market's ability to identify customers' needs and to attract the necessary investment. This is of particular importance given the need for Australia's electricity networks to be resilient, both to the direct impacts of climate change, and to the changing patterns of flows of electricity that may accompany carbon reduction policies.

It is noteworthy that the existing transmission frameworks (including recent reforms) are already facilitating demonstrable, and non-trivial, shifts in the generation mix (towards lower emissions).

The attached submission seeks to explain in some detail the careful process of refinement and improvement to the transmission regulatory framework that has occurred over a number of years sponsored by the Ministerial Council on Energy (MCE).

The submission also responds in specific detail to observations and findings in the Update Paper, and highlights the considerable reform effort that has recently been undertaken to strengthen the framework for national transmission planning and investment.

Specifically, the submission focuses upon:

- the arrangements that exist for coordinating transmission planning across the NEM and ensuring that there is sufficient and efficient inter-regional transmission investment;
- the economic test that is applied to assess the efficiency of transmission investments (the 'Regulatory Investment Test for Transmission', or RIT T);
- the incentives that apply to transmission network service providers with respect to investment;
- the return that investors in network assets require, given the risk borne in the 'new normal' post-GFC world ;
- the merits of a national system of transmission charging;

- the rationale for, and characteristics of, the current system whereby network investors are able to appeal the regulator's decision; and

- the appropriate specification of reliability standards for transmission networks .

I would appreciate the opportunity to meet with you and your review team as you work to prepare your final consolidated report to discuss the information provided in our submission, and to provide any further insights that may be helpful.

Please do not hesitate to contact my office on 07 3860 2607 if you would like to arrange a time to meet to discuss these matters, or if Grid Australia can be of further assistance.

Yours sincerely,

Gordon Jardine
Chairman
Grid Australia

grid australia
BACKBONE OF THE NEM

Garnaut Climate Change Review Update 2011

Response to Transforming the Electricity Sector (Update Paper 8)

April 2011

Powerlink Queensland · TransGrid · ElectraNet electricity transmission · TRANSEND · SP AusNet A member of Singapore Power Group

Table of Contents

1. Key messages

1.1 Who are we?

Grid Australia represents the owners of the main electricity transmission networks across southern and eastern Australia (which is the region covered by the National Electricity Market, or NEM) and Western Australia. Collectively, our members own and operate more than 47,000 km of transmission lines with a combined value of $12 billion, and with a responsibility for funding and delivering an annual investment program of approximately $2.2 billion.

The purpose of this submission is to respond to a number of the observations and findings in the Garnaut Climate Change Review Update 2011 paper: 'Transforming the Electricity Sector, Update Paper 8' (Electricity Update Paper) that relate to the performance of electricity networks and the frameworks under which they operate.

1.2 Challenges of climate change policy

Grid Australia understands the considerable challenges of finding mechanisms that can deliver meaningful carbon signals to businesses and households while ensuring that Australia's power industry remains both sustainable and efficient. Grid Australia supports this objective, but it is a complex problem that tempts easy solutions.

A clear target for the Electricity Update Paper is the current regulatory framework that applies to energy networks. It is asserted that the current arrangements encourage inefficient network investment and cause unnecessarily high electricity prices. However these assertions are not supported by an understanding of the robust economic regulatory framework that operates in the NEM and the principles behind it.

Grid Australia supports enhancements to the NEM that have been built upon COAG's more than decade long program of industry reform, a program that has made the NEM one of the world's most efficient, competitive and reliable power systems.

Given the success of the framework to date, where the broader objectives of government cannot be met through prices or decisions that are efficient within the context of the electricity sector alone, Grid Australia also supports the introduction of measures that operate alongside the NEM framework.

What is essential is that such measures complement but do not distort the framework, given that doing so would impair the market's ability to identify customers' needs and to attract the necessary investment. This is of particular importance given the need for Australia's electricity networks to be resilient, both to the direct impacts of climate change, and to the changing patterns of flows of electricity that may accompany carbon reduction policies.

1.3 The current framework is the product of recent, substantial reform

The Electricity Update Paper appears to demonstrate a lack of awareness of the careful process of refinement and improvement to the transmission regulatory framework that has occurred over a number of years.

Sponsored by the Ministerial Council on Energy (MCE), that process has included substantial reviews such as the COAG Energy Market Review (Parer Review), the review by the Expert Panel on Energy Access Pricing, as well as a review by the Energy Reform Implementation Group (ERIG), which reported on measures to achieve a fully national electricity grid[1]. The COAG reform process has considered the findings of each of these reviews in establishing its reform program which has included the following significant steps:

- the Australian Energy Market Commission (AEMC) was established in 2005 to ensure, amongst other things, that the National Electricity Rules (Rules) for planning and delivering transmission services were robust and based on a clear economic objective;
- at the same time, the Australian Energy Regulator (AER) was formed with the power to review the economic efficiency of the investment decisions made by the transmission businesses under those Rules — those reviews must be conducted according to well-established principles of competitive neutrality, favouring neither private nor government-owned transmission businesses;
- in 2008, a limited system of merits review came into operation to ensure that all stakeholders' interests were properly taken into account by the AER in reaching its decisions while minimising the delay and costs to interested parties;
- a nationally co-ordinated planning regime came to fruition in 2010 with the publication by the Australian Energy Market Operator (AEMO) of the first National Transmission Network Development Plan (NTNDP) — a key focus of the Plan is on testing the need for further backbone transmission capacity across the NEM (including interconnectors); and
- since August 2010, all major transmission investments have been required to pass the new Regulatory Investment Test for Transmission (RIT-T), a test that specifically requires the full range of market-wide economic benefits to be considered when testing the efficiency of a transmission project.

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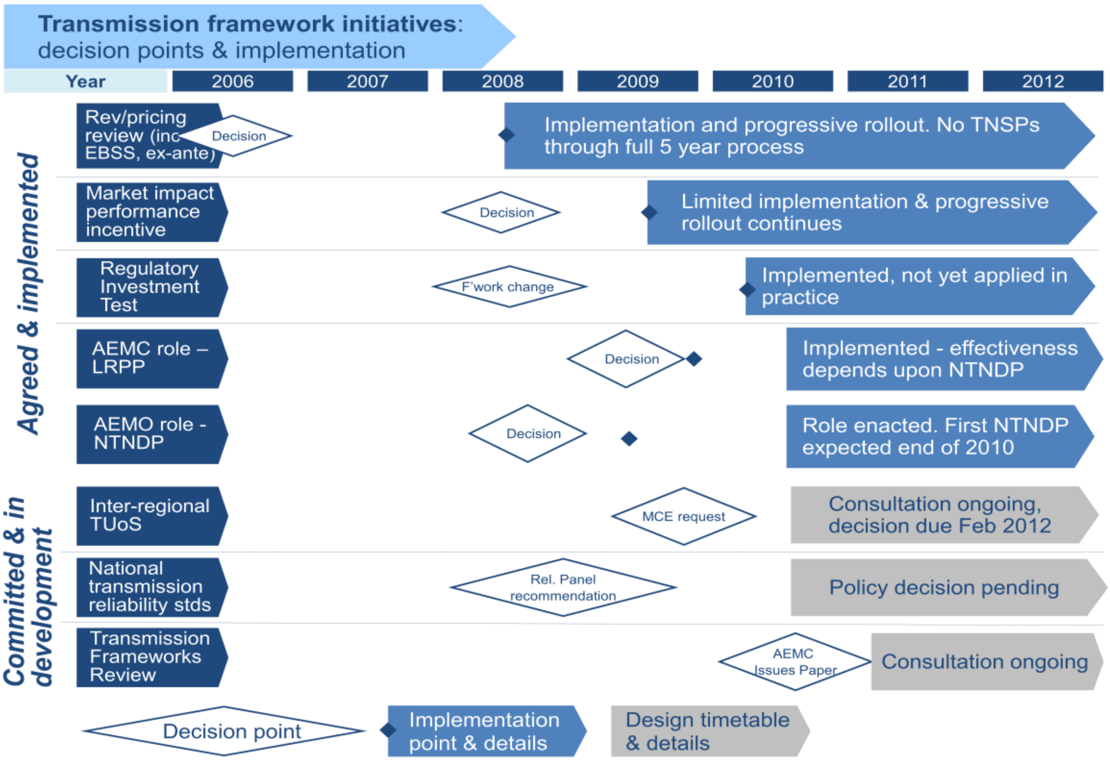
1 The MCE also asked the ERIG to develop proposals for measures to address structural issues affecting ongoing efficiency and competitiveness and measures to ensure transparent and effective financial markets to support energy markets.

The full benefit of these reforms will necessarily take time to mature and flow through to the broader economy.

Grid Australia also notes that the interaction of climate change policies with energy markets has recently undergone a comprehensive review by the AEMC[2]. Following this review the MCE directed the AEMC to undertake a review of the transmission framework. Grid Australia considers that the AEMC review is the appropriate forum to address transmission framework issues, and reiterates the need for any proposed changes to the existing transmission framework to be supported by a clear and well evidenced rationale.

The figure below sets out the timeline of recent and on-going reforms. It is notable that a number of important initiatives have either only recently been implemented or have not yet commenced.

Figure 1: Time Line for Transmission Framework Initiatives



1.4 Specific concerns with Electricity Update Paper's findings

Grid Australia is concerned that the Electricity Update Paper, in failing to understand the NEM transmission framework and conduct the required analysis, is recommending

2 AEMC, *Review of Energy Market Frameworks in light of Climate Change Policies*, 30 September 2009.

changes that risk impeding the efficiency of price signals and investment, and the resilience of networks.

The following table reproduces the main findings and recommendations of the Electricity Update Paper and sets out a summary of Grid Australia's response which highlights significant issues with the proposed way forward.

In this regard, Grid Australia regrets that there was no formal consultation with electricity industry stakeholders, including transmission investors and operators, prior to publishing the Update Paper. Doing so may have avoided the factual errors and incomplete analysis identified below.

Table 1: Main Findings, Recommendations and Response

Electricity Update Paper Finding	Grid Australia Response
All transmission planning should be transferred to AEMO through its National Transmission Planner function so as to advance investment in interstate connections.	A national, 'whole of grid' approach already exists for network planning as a result of recent and comprehensive COAG driven reform. It appropriately balances the need for identification of strategic national projects with the practical realities of regional transmission investment and service delivery.
Transmission Network Service Providers (TNSPs) are not well equipped to undertake economic assessments for transmission investments, most importantly an assessment of competition benefits and real options value.	Competition benefits have been considered in TNSP planning decisions, and Grid Australia is working in cooperation with AEMO to develop approaches and ensure that these benefits are included in transmission assessments where appropriate. That said, valuing competition benefits and real options is complex (even for economists), and intuition would suggest that competition benefits are rarely material if only true economic benefits are considered in the assessment.
The regulatory regime provides an incentive for network businesses to gold-plate the network (and gold-plating has been observed).	The existing framework encourages efficient investment, and in fact penalises TNSPs for every additional dollar they spend. The current framework balances the risk between under investing and over investing in network infrastructure, and provides equal incentive for investment within and between regions. The increase in expenditure observed in recent years can be explained in part by the minerals-boom driven increase in materials prices, the effects of continued economic growth, and the age profile of Australia's network assets.
The return on capital does not reflect the risks and costs incurred by the network businesses.	The Law and Rules require the return to be commensurate with risk, and the methods employed are consistent with international practice. The current parameters and approaches reflect extensive and

Electricity Update Paper Finding	Grid Australia Response
Government owned businesses do not need to earn a commercial return.	numerous reviews extending over the past 15 years of market evolution. The most recent 5-yearly review was concluded by the AER in 2009. The proposition that government owned businesses should not earn a commercial return is inconsistent with the accepted view that the cost of capital for a project is unaffected by its ownership, and would otherwise imply a subsidy from tax payers. Policies in support of this competitive neutrality principle were established as an integral part of the Hilmer competition reforms in the early 1990s and endorsed by COAG. The basis for questioning this principle has not been clearly argued in the Electricity Update Paper nor tested through consultation.
The absence of a national system of transmission pricing is creating a barrier to interconnector investments.	There is no direct link between transmission pricing and the incentives for transmission investment. The structure of transmission prices does not have any effect on whether or not transmission projects proceed.[3] It affects neither the incentives of transmission investors nor the economic outcomes of the RIT-T. In any event, a Rule change before the AEMC provides a proportional response to addressing the efficiency concerns of charging customers for assets they use across regional boundaries.
The merits review process favours the businesses and should instead require the entire decision to be reviewed.	Merits review is a key component of a well-functioning regulatory regime and ensures accountability in regulatory decision-making. The merits review process limits the scope of appeals to material before the AER at the time of its decision, and is designed to prevent vexatious or non-material claims. The majority of appeals to date have found material errors in the original decision. A full rehearing of decisions would provide a disproportionate response given it would incur significant costs and time and would call into question the role of the regulator.

[3] As noted below, if inter-regional charging improves the efficiency of prices for final customers, then customers' locational decisions may be affected, which in turn would have an indirect effect on the need for new investment.

Electricity Update Paper Finding	Grid Australia Response
The reliability standards in most states are crude and lead to higher standards compared to an economic approach.	Grid Australia supports the single, national framework for determining reliability standards across the NEM proposed by the AEMC. This involves standards being determined economically and expressed deterministically. Standards should also be set independently from network businesses. Expressing the standards in a deterministic form supports transparency of service delivery and holds network businesses more accountable to customers.

A more detailed explanation of these matters follows in the remainder of this submission.

1.5 Submission outline

The remainder of this submission responds in specific detail to the observations and findings in the Update Paper, and further highlights the considerable reform effort that has recently been undertaken to strengthen the framework for national transmission planning and investment.

Specifically, the remainder of this submission focuses upon:

- the arrangements that exist for coordinating transmission planning across the NEM and ensuring that there is sufficient and efficient inter-regional transmission investment;
- the economic test that is applied to assess the efficiency of transmission investments (the 'Regulatory Investment Test for Transmission', or RIT T);
- the incentives that apply to network service providers with respect to transmission investment;
- the return that investors in network assets require, given the risk borne;
- the merits of a national system of transmission charging;
- the rationale for, and characteristics of, the current system whereby network investors are able to appeal the regulator's decision; and
- the appropriate specification of reliability standards for transmission networks.

These are addressed in turn.

2. Co-ordinated transmission planning and inter-regional transmission investment

- The existing framework applies a 'whole of grid' approach to transmission planning of major flow paths in the NEM
- It facilitates nationally coordinated planning for strategic flow paths but relies on regional planning and investment decisions so that the practical realities of investment and service delivery can be taken into consideration
- This existing framework was the result of relatively recent and deliberate policy decisions at the highest levels of government to address the very issues raised in the Electricity Update Paper, and resulted from extensive consultation with the industry and electricity users
- There is already evidence of the new framework working; however, given it is still relatively new it needs time to mature.
- There are a number problems associated with a not-for-profit central planner model that need consideration should this model be considered further – this includes the application of performance incentives and accountability for transmission service delivery

2.1 Electricity Update Paper Findings

The Electricity Update Paper makes a number of observations about the effectiveness of national planning in the NEM. The Paper argues that there is a failure of nationally co-ordinated planning that is leading to the suboptimal development of the national grid. The evidence, according the Electricity Update Paper, is the lack of long-distance inter-state links while expenditure on local transmission and distribution investments, justified by supplying the extreme peak with reserve capacity, continues.

The Electricity Update Paper suggests that it is highly unlikely that a seamless national network can be built by five state-based transmission planners with regional focuses. It is argued that part of the problem is that the entity with the national transmission planning responsibility (AEMO) has no power to actually develop projects; rather its plan is presented purely as a guide to state based planners who are free to ignore it[4]. The solution that is advocated is for AEMO to assume all transmission planning responsibility and for each state to separate its transmission ownership from its transmission planning.

Grid Australia notes that a framework for national transmission planning has only recently been implemented and that this framework was the outcome of a substantial review of the

4 Garnaut, R., *Garnaut Climate Change Review – Update 2011, Update Paper eight: Transforming the electricity sector*, March 2011, p. 34.

electricity market that was undertaken for all Australian Governments[5]. This included extensive consultation with all parts of the industry and customers, with the key elements of that regime endorsed by COAG. It is far too early to draw an inference that it has or will 'fail' and, given the careful and deliberate policy decisions that led to the current framework, inappropriate to recommend large scale changes based upon only a casual analysis.

In fact the new framework was developed to address the very issues the Electricity Update Paper has identified, and early indications should provide confidence that interconnector projects will be identified and developed in an efficient manner.

The key elements of the new framework are discussed below.

2.2 Framework for national coordination of transmission investment

Efficient national planning of transmission investment requires the strategic, national context for projects to be integrated effectively with practical, local knowledge. There has been a considerable amount of work undertaken in recent years aimed at improving the institutional arrangements and regulatory framework to ensure that this goal is met. As a consequence of recent reforms, there is now a new framework that incorporates an effective 'whole of grid' approach to network planning.

Under the framework that is now in place, national strategic projects are identified through the NTNDP. The NTNDP is a planning coordination document that AEMO is required to prepare. The plan, to be published annually, seeks to consider and assess the appropriate course for the efficient development of the national transmission grid over a planning horizon of at least 20 years. It focuses on important strategic national flow paths across regional pricing boundaries. The plan is developed in close consultation with the TNSPs and is subject to public consultation. AEMO published the first NTNDP in December 2010.

TNSPs' Annual Planning Reports (APR) then translate the strategic national plan into near term regional transmission development plans based on joint planning with distributors. Indeed, it is a requirement of the Rules for APRs to have regard to the NTNDP.

The regional planning process conducted through the APRs is an important step to ensuring that transmission planning takes account of the practical situation in the relevant area. By necessity, the strategic national plan that AEMO develops will be based upon high level assumptions about the cost of projects and other matters, like the potential for new generation entry. This plan will also identify projects some time prior to the projects becoming efficient. The APRs take this analysis to the next level of detail and factor in

5 Energy Reform Implementation Group, 2007, *Energy Reform: the Way Forward, Report to the Council of Australian Governments*, January.

such matters as the availability of easements, and the impact that local environmental and land use requirements will have on future generation and transmission investments.

Regional Planning will also factor in the potential for efficiency gains to be made through coordinating asset replacement and refurbishment expenditure with augmentations, as well as updated estimates of the cost of projects based upon more recent experience. This more detailed analysis requires 'on the ground' knowledge of conditions for transmission and generation investment. It also requires the ability to integrate with other transmission projects as well as joint planning with distributors for meeting distribution network needs in the area. This model also ensures that network investment decisions are made by the business accountable for service delivery to customers.

In addition, the newly enhanced RIT-T, which is discussed further in the following section, contributes to the delivery of transmission investment that is efficient from the perspective of the NEM as a whole. The test requires the net benefit of proposed investments to be determined without reference to regional boundaries. Indeed the Rules require the test to specify the method or methods permitted for estimating market benefits that may occur outside the region in which the TNSP's network is located.[6] In addition, the RIT T requires extensive consultation, including with AEMO, which provides the opportunity for any national, strategic issues to be raised and taken into account.[7]

Further, when the AER sets the revenue requirements for TNSPs, it is specifically required to have regard to the most recent NTNDP and any submissions made by AEMO. As a matter of practical reality, the AER is likely to place particular weight on the views of AEMO about the appropriateness of the projects that a TNSP has proposed. This, therefore, provides a further check on TNSPs investment decisions.

Lastly, a further safety net exists to address situations where, in spite of the extensive consultation undertaken through the planning process, important strategic projects are not progressed. This is the Last Resort Planning Power (LRPP) that resides with the AEMC. The LRPP empowers the AEMC to direct one or more Registered Participants to apply the RIT-T in relation to a potential transmission project it identifies. The AEMC is required to report annually on whether or not the LRPP should be exercised. The AEMC has not

[6] Clause 5.6.5B(c)(10)(iii) of the National Electricity Rules. The RIT T comprises a number of levels. The Rules require the AER to set out the detail of the economic test and methodologies for assessing transmission projects, and also sets out the consultation obligations and dispute resolution processes. This consultation and dispute resolution process is aimed at both ensuring that the test is applied correctly to network investments, as well as to ensure that non network options (such as demand side response or embedded generation) are considered on an equal basis. The AER has determined the economic test for transmission investments as required, and has also issued a guideline that provides further guidance as to how that test should be applied.

[7] It is also worth noting that Registered Participants, the AEMC, Connection Applicants, Intending Participants, AEMO and interested parties may dispute the conclusions made by a TNSP in its project assessment to the AER should they consider the test has not been applied appropriately. As a matter of practical reality, the AER is likely to place particular weight on the views of AEMO should such a dispute arise.

yet seen a need to exercise this power. Indeed, in its latest annual report, the AEMC concluded that while there are some constraints that may increase in terms of the extent to which they bind inter-regional power flows, the TNSPs and AEMO are both already developing measures to address these constraints.[8]

Accordingly, it is incorrect to assume that TNSPs are free to ignore the contents of the NTNDP or the views of AEMO when deriving their own plans and making decisions to invest. Rather, a series of checks and balances exist over the decision making of TNSPs, with the NTNDP, and AEMO more generally, having central roles to play.

2.3 Operation of the framework to date

As already highlighted, the new framework and institutional arrangements described above have not yet had a chance to work fully. Therefore, caution should be exercised in drawing any inference as to whether or not the new regime is 'failing' or a success. However, the indications to date are that the reforms will be effective in delivering coordinated national planning.

In particular, there are currently a number of investigations into interconnector projects in progress. Specific examples of such investigations include the following:

- SA interconnector feasibility study – ElectraNet and AEMO worked together in an open and transparent manner to undertake a feasibility study to determine if a project to augment interconnector capacity between South Australia and Victoria or New South Wales could be feasible (a final report was published in February 2011). Further work is now underway to investigate in more detail the economic feasibility of particular options and whether a RIT-T should be undertaken on these options.

- Powerlink and TransGrid are currently undertaking a further round of upgrade studies on the Queensland New South Wales Interconnector (QNI), consistent with the market development scenarios and options reported in the 2010 NTNDP. This assessment will involve engagement with AEMO to ensure consistency with future NTNDP studies.

- AEMO and TransGrid have undertaken preparatory work and are intending to investigate the benefits of upgrading the Victoria to New South Wales interconnector.

In addition, while the NTNDP identified a number of projects that it considered to require early attention by planners, it also observed that planning had already commenced or was about to commence in relation to each of those projects.[9]

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8 AEMC, *Investigation into the Exercise of the Last Resort Planning Power: 2010*, 10 November 2010, p. i.

9 AEMO, *National Transmission Network Development Plan, Executive Briefing 2010*, pp.23-25.

2.4 Issues with a central planning model

If a central planner approach facilitated through AEMO is to be considered further, it is important to understand that a number of problems arise with this approach. The potential problems identified below are primarily based on the experiences in Victoria where AEMO is the network investment planning body.

Most importantly, a centralised process for investment decision making is incongruous with regulatory policy developments over the past decades, which reflect the inability of a centralised, economy wide decision maker to respond quickly and appropriately to changes in market requirements, commercial drivers and technological change.

Rather, the focus of regulatory policy development has been to encourage decentralised decision making and to design regulatory regimes so that decentralised decision makers are motivated to make decisions that promote the social good. These measures are referred to generally as incentive regulation, and some of the measures that apply to TNSPs and the overall philosophy is discussed further in Box 1.

Box 1: What is incentive regulation?

The term incentive regulation (or, alternatively, incentive compatible regulation) refers to measures included in the regulatory regime that are designed to align the commercial interests of regulated businesses with the social good (which is generally taken as advancing economic efficiency). In short, such measures enable businesses to earn additional profit in circumstances where efficiency is advanced. There are a number of aspects of the regulatory regime that provide TNSPs with financial incentives for advancing the social good, which include the following:

- *Application of a price control* – a revenue cap applies to TNSPs[10]; therefore, the allowed revenue that is determined for a TNSP in a price review is fixed and not reviewed for a defined period (typically five years, with the exception of defined events).[11] This means that the level of profit that TNSPs earn is tied to their actual expenditure, thus additional profit can be earned by controlling expenditure. Such actions benefit the TNSPs in the short term (by raising profit, all else constant) and customers in the medium term. The reward for controlling expenditure arises if operating and/or capital expenditure is reduced, and also results if one form of expenditure can be substituted for another and lower the overall cost, for example, though pursuing non-network solutions.

[10] Grid Australia notes that the same incentive properties for cost efficiency exist irrespective of whether a revenue cap or a price cap applies.

[11] For operating expenditure, a continuation of the efficiency benefit from one period to the next is allowed through a measure known as the efficiency benefit sharing scheme. This measure is designed to equalise the incentive to make operating expenditure improvements over the course of a regulatory period.

- *'Revealed' cost efficiencies passed through to customers* – the cost savings that a TNSP achieves through a regulatory control period are subsequently passed onto customers at the next periodic review of prices. This is because the 'revealed' efficient level of cost is factored into the new prices given the regulator will have regard to expenditure and efficiencies that occurred in the preceding period.
- *Service target performance incentive scheme* – when the revenue caps are determined, targets are set for different measures of service performance over the period between reviews. The revenue that TNSPs are allowed to earn in each year is adjusted to reflect the TNSP's actual performance compared to this target. An important role of this incentive scheme is to act as a counterweight to the incentive to reduce cost discussed above to discourage cost savings at the expense of service reductions. However, the scheme also encourages an increase in expenditure where this may generate a commensurately high benefit to customers, for example, by taking transmission assets out of service for maintenance or augmentation outside of system peak times, albeit at the expense of having to pay higher wages and contractor costs.

The underlying philosophy behind incentive regulation is that it encourages the entities that are in the best position to make operational and investment decisions (that is, the owners and operators of the assets) to make use of their full set of private information to make decisions that promote the social good, including to innovate where possible. This is likely to result in far superior outcomes compared to those decisions being made or dictated by a 'central planning' entity that would have neither the same level of motivation or information.

AEMO is a not-for-profit organisation. It follows that if AEMO were to become the entity that makes all transmission investment decisions, the capacity to use financial incentives to encourage innovation in transmission investment decisions would be lost (the use of financial incentives in this way – which is referred to as incentive regulation – only works where the entity has a commercial objective).

The consequence of not being able to apply incentive regulation to AEMO plays out in a number of ways. For example:

- There would be no scope for incentive regulation to encourage innovation about the optimal means of augmenting the network to meet a defined obligation.
- There would be no role for incentive regulation to encourage an optimal trade-off between network and non-network options for resolving a constraint. This is because there would no longer be an incentive to minimise costs, and hence, the substitution of non-network for network investment within required timeframes.
- There would be no role for incentive regulation to encourage the optimal trade-off between asset investment and maintenance. These roles would instead be split between a central planner and a network service provider. Indeed, the decision for efficient replacement or refurbishment of network assets may be crowded out by a less efficient augmentation decision by a central planner.

- There would be no commercial driver for investment to be responsive, timely and efficient and no checks and balances to guard against over-investment in network infrastructure.

The use of financial incentives to harness the private information of regulated businesses and motivate innovation and continuous improvement has been one of the major developments in economic regulation in recent decades, and removing it would be a major step backwards.

A central planner model would also result in a division of responsibility that unfairly places all of the financial risk with respect to service obligations and service incentive schemes with the TNSP, while the investment decision-making body bears none. Under the existing arrangements TNSPs bear the consequences of outages that impact on market performance. Removing one of their tools for managing this, i.e. the ability to plan new investments, potentially creates a financial risk for TNSPs that they are not able to effectively manage, as well as reducing the benefits to the market from the service incentive scheme.

3. Application of the Regulatory Investment Test for Transmission

- The RIT-T commenced in August 2010 and was the product of a major review for COAG,[12] followed by a more detailed review by the AEMC at the direction of the MCE.[13]
- It has been developed as a result of concerns that the full benefits of various network development options were not being addressed by the former regulatory test process. This includes consideration of benefits to the market including reduced transmission congestion and increased competition across the market
- The RIT-T has an important role to play in ensuring only efficient transmission investment occurs
- The new RIT-T contains important differences over the previous test, most notably, the requirement to consider market benefits for all prospective projects [14]
- There is value in ensuring competition benefits and options values are assessed appropriately, however, caution needs to be taken in managing expectations with respect to the influence these benefits will have on investment decisions
- To the extent the RIT-T does not capture some broader economic or social benefits, the framework should not preclude governments factoring these benefits into decisions to contribute to the costs of transmission assets

3.1 Electricity Update Paper Findings

The Electricity Update Paper makes a number of claims that relate to the assessment of potential investments through the RIT-T. Firstly, the paper claims that TNSPs have under-utilised the opportunities within the existing regulations to identify benefits. Secondly, the Electricity Update Paper suggests TNSPs do not have the economic skills to undertake a proper analysis of benefits.[15]

Again, Grid Australia considers that these comments reflect a misunderstanding of the nature of the RIT-T, how it is applied in practice and the practical issues associated with

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12 Energy Reform Implementation Group, 2007, *Energy Reform: the Way Forward, Report to the Council of Australian Governments*, January.

13 AEMC, National Transmission Planning Arrangements, Final Report to MCE, 30 June 2008.

14 We note that a preferred option may have negative net economic benefits where the identified need is for reliability corrective action.

15 Garnaut, R., *Garnaut Climate Change Review – Update 2011, Update Paper Eight: Transforming the electricity sector*, March 2011, p.33.

estimating (and the likely importance of) certain of the benefits that may be provided by transmission investments. Moreover, Grid Australia notes that the current RIT-T – as part of the wider planning and investment decision making arrangements discussed in the previous section – has been the subject of extensive, recent review and consultation with industry and customers, with the key principles endorsed at the highest level of government.

3.2 The new 'Regulatory Investment Test for Transmission'

At the outset, it needs to be understood that the purpose of the RIT-T is to identify the most efficient solution and optimal timing for meeting a defined need on the network. As such, it seeks to ensure that only efficient transmission investment is undertaken. This would include a situation where a transmission investment had the effect of 'crowding out' more efficient non-network solutions, like local generation or demand side response. Thus, the test has an important role as market participants – and, in most situations, final customers – would bear the net costs should inefficient transmission projects proceed.

Like many of the elements of the transmission planning framework, the RIT-T is also new (having commenced operation in August 2010) and was designed to address what were considered as shortcomings in the previous test. The most important change that was made was to require wider market benefits to be considered in all projects. This reflected a concern that TNSPs may have been encouraged under the previous test to focus more on projects to meet customer reliability (as the previous test provided a simpler route for justifying such projects) and could have missed out on possible enhancements that were justified in terms of the other market benefits they would create.

This change in the test was complemented by the new transmission planning arrangements discussed above, as the NTNDP would assist in identifying where an enhancement to a reliability augmentation would provide wider market benefits. As with the other elements of the new transmission planning framework, it is too early to draw an inference about the effectiveness of the new test.

Grid Australia notes, however, that the mere fact that most of the transmission projects assessed by TNSPs are motivated by reliability purposes is not in itself a reason for concern.

- First, the majority of efficient transmission investments will always be motivated by the need to maintain reliability of electricity supply to customers. As demand grows, new generation capacity is required, and network reliability projects are merely the additional transmission that is required to allow that additional generation capacity to reach the customer. In contrast, the other market benefits from transmission arise from such factors as the transmission investment allowing an existing lower cost generator to be operated more often and substitute for a higher cost generator, or from changing a generator's locational decision so that it to locates near a lower cost source of fuel. While this latter class of market benefits is real and valid, the benefits nevertheless should be expected to be much lower than reliability benefits and hence that the projects that could be justified on the basis of market benefits would be fewer in number.

- Secondly, TNSPs have undertaken numerous assessments of 'market benefits' projects over recent years. However, if the initial assessment suggested that the project would not pass an economic test, then further analysis would cease and the initial assessment would not generally be exposed publically for further scrutiny. To do so would have added an unnecessary administrative cost onto TNSPs as well as those who wish to review the proposal. In the future, however, all projects of national importance that may be feasible would be identified and reported in the NTNDP, so that stakeholders would be aware of when more detailed assessments of projects should be expected.

3.3 Application of the RIT-T: Competition Benefits and Real Options

One of the particular comments made in the Electricity Update Paper is that TNSPs have not availed themselves of the full options that are available to transmission planners under the RIT-T to justify transmission projects, most notably the capacity to value competition benefits and real options. Prior to discussing these in detail, Box 2 explains at a high level some of the economic benefits that may flow from a transmission project.

Box 2: Economic benefits from a transmission project

As the RIT-T is an economic test, it requires that only the increase in aggregated benefits across market participants be counted as a benefit when evaluating transmission projects.

When the transmission network is augmented between regions and this affects market prices, then substantial care is required to identify the true economic benefit. The most obvious effect from such an augmentation is that customers in the region where prices are lowered would be made better off. However, if prices drop in one region (the importing region) then prices are likely to rise in the adjoining region (the exporting region) and thus come at the expense of other customers. Moreover, generators are also affected, being worse off if located in the region where prices fall, but better off in the region where prices rise. It is clear that much of the benefit that accrues to individual market participants is cancelled out by adverse impacts borne by other participants. In economic terms, where benefits cancel out in aggregate they are transfers between parties and not true economic benefits and should therefore not be counted when evaluating the merits of a project.

In order to avoid inadvertently counting transfers, the RIT-T requires a focus directly and transparently on the different sources of economic benefit that may flow from a project. These benefits include the following:

- *Reliability* – which is an increase in the likelihood that power will be available to customers when sought (or, equivalently, a reduction in the likelihood that energy sought will not be able to be served).
- *Generation operating costs* – where the transmission project eliminates a constraint and so allows more use to be made of a generator with low operating costs in preference to one with high operating costs.

- *Generator capital costs* – where the transmission project allows for a better sharing of generation reserve capacity across the network, and so reduces the need for new generation capital investment, or the transmission project enables and encourages the new increments of generation investment to be lower cost plant. It is noted, however, that a trade-off occurs between the reliability benefits and generator capital costs given that a deferral of generation entry will also imply that less reserve capacity would exist at any point in time, and so the benefit is the net effect of these factors.
- *Losses* – new transmission projects can reduce aggregate network losses, which is a direct benefit.
- *Increased efficient electricity usage* – where customer prices were previously in excess of the social cost of production (i.e., inclusive of externalities) and a transmission project reduces prices to customers, then the additional demand would deliver customer benefit that exceeds the social cost of production, which is also an economic benefit.
- *Project flexibility* – in addition, different transmission projects will provide differing levels of capacity to adjust in response to new information in the future. For example, a transmission project that can be added in stages provides more scope to adjust to observed future rates of demand growth. Alternatively, by constructing a larger project than otherwise, would provide the flexibility to connect new generators in a region should connection be sought. The 'option' value of this flexibility can validly be counted when evaluating the merits of different projects.

The term 'competition benefits' refers to any of the benefits above that may be increased as a result of a transmission project enhancing the degree of competition between generators. The most likely benefit to be advanced is the 'increased efficient electricity usage' benefit.

Estimating these benefits requires a number of sophisticated modelling techniques. For example, evaluating reliability benefits requires a model of the individual and joint likelihoods that electricity plant (generation and network) will be out of service at any point in time, estimating the generation operating cost benefit requires a model of the future dispatch of generators and estimating the generation capital cost benefit requires a model of the future investment in generation over a reasonable timeframe.

Grid Australia notes that there have been a number of studies in which TNSPs have sought to include an estimate of competition benefits in the total benefits that arise from a transmission augmentation, such as the recent joint study into a new interconnector between New South Wales and Queensland that has been investigated by TransGrid and Powerlink.[16] The reality is, however, that estimating these benefits is complex – even for

[16] Powerlink and TransGrid (2008), Potential Upgrade of Queensland/New South Wales Interconnector (QNI) - Assessment of Optimal Timing and Net Market Benefits, Final Report, October. Note that the standard technique for estimating competition benefits delivers an estimate of the aggregate benefit *inclusive of the*

an economist – and the resulting economic benefit inevitably is likely to be relatively small.

- First, in order to quantify a competition benefit, an assumption is required about how a transmission link will change the intensity of competition amongst generators, and then how that will affect generator bidding behaviour.

- Secondly, the outcome of the change in bidding behaviour is a lower generation price and hence a lower cost to customers. However, much of this change, in the form of prices in the market, is a wealth transfer from generators to customers and is not properly counted as an economic benefit. Rather, an economic benefit arises to the extent that the price to final customers falls and this fall in price induces additional (efficient) consumption. Given the low observed price elasticity of demand for electricity, this benefit would be expected to be small. In addition, for a true efficiency gain to arise at all, the delivered price of electricity must previously have exceeded the social cost, so that additional consumption is efficient.

Turning to real options, many different types of real options may exist in relation to a given project. The Electricity Update Paper correctly points out that by overbuilding transmission capacity, the option would be created to connect new generation in the area at low cost and more quickly than otherwise, which may have a benefit. Equally, real options considerations may also justify spending on higher cost interim measures that allow a large augmentation to be deferred, or to opt for a modular augmentation that is expected to be higher cost, as each of these options provide the flexibility to wait for new information before committing to an irreversible investment.

However, while it is clear that assessing options value will require sophisticated modelling tools, Grid Australia is committed to ensuring that the relevant techniques are developed to be used in the appropriate cases.

3.4 Consideration of broader benefits

The Electricity Update Paper identifies a number of possible benefits from increased interconnection. These benefits include environmental benefits, such as less reliance on high emissions plant to support local demand peaks.[17]

At the outset, it is worth stating that the existing RIT-T is capable of incorporating benefits associating with a carbon price and the costs of meeting a renewable energy target. This is made clear in the AER's guideline on how to apply the RIT-T, which discusses the consideration of carbon pricing into operating costs. However as previously noted, and

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contribution of enhanced competition, and so a disaggregated estimate of the competition benefits alone may not be presented.

17 Garnaut, R., *Garnaut Climate Change Review – Update 2011, Update Paper eight: Transforming the electricity sector*, March 2011, p.32

consistent with the National Electricity Objective set out in legislation the test limits the consideration of benefits to those who consume, produce or transport electricity.

As a consequence, broader benefits, and costs, that may be two or three times removed from those within the market are not captured. Such benefits, which are generally considered as externalities, may include improved environmental outcomes (where the outcome is not properly ‘priced’) and flow on effects of the direct beneficiary to other firms or industries, such as increased exports, job creation and regional development. Unde the Rules both AEMO and TNSPs are bounded by the scope of the National Electricity Objective in applying the RIT-T.

Introducing broader economy-wide factors within the RIT-T is likely to introduce considerable uncertainty into transmission investment decision making. This is because of the additional assumptions that would be required, and the uncertainty associated with getting those assumptions right. Given this, externalities or other social objectives have to date been addressed outside of the NEM framework. The application of the renewable energy target, and carbon pricing, are examples of this.

While broader benefits may not be considered within the RIT-T, this does not mean that broader considerations cannot be applied to transmission investment. Indeed, a role for governments may be to financially contribute to transmission investment where broader benefits are likely to exist or where additional transmission investment assists in the achievement of social policy goals.

A model where governments make contributions to transmission investments outside the NEM framework allows Government to contribute to investments on the basis of broader objectives while ensuring electricity customers do not solely bear the burden of these decisions and the integrity of the NEM decision making framework is maintained.

Moreover, there is nothing in the existing framework that prevents this sort of policy response from happening today. Addressing social policy issues outside of the NEM framework also ensures that broader assessments can take into consideration particular priorities for the government of the day.

4. Incentive regulation and investment decision making

- In developing the current framework careful consideration was given to the balance between under investing and overinvesting in network infrastructure. We note that the Electricity Update Paper does not expressly consider the consequences of deliberately reducing reliability outcomes in electricity service delivery.
- The same incentives that apply to invest in regional transmission apply to investments in transmission interconnection
- The existing framework encourages efficient investment in transmission networks, it in fact penalises TNSPs for every additional dollar they spend
- While additional investment in networks has been undertaken in recent years, this investment has been warranted and necessary

4.1 Electricity Update Paper finding

The Electricity Update Paper expressed the view that network businesses have an incentive to over-invest in network assets,[18] which in turn is argued to have led to substantial gold plating of electricity networks (with the exception of interconnectors between regions, where the contrary concern was raised).

The Electricity Update Paper also states that the existing financial incentives for state owned network providers to over invest, coupled with the political cost of any failure, have the potential to overwhelm any countervailing incentives to minimise operational costs.[19] These failures that were considered to exist in the regime were considered to have contributed substantially to the recent electricity price rises and that strengthening and improving the regulatory rules may yield large benefits in lower rates of increase in electricity prices. On the basis of these claims, the Paper indicates that there is a need for an early and searching independent review of the framework.

Grid Australia considers that these findings reflect a material misunderstanding of the incentive properties of the regulatory regime for transmission, and also misstate the actual needs for network investment at the present time. Given the significant errors in the Electricity Update Paper, and the potential for those claims to create expectations that

18 The Paper also asserted that network businesses have an incentive to overstate the size of their regulatory asset bases. In reality, the businesses have no discretion over the size of their regulatory asset bases. Rather, this is a product of an initial regulatory asset base that was determined and 'locked in' over a decade ago for most network businesses, plus actual capital expenditure since that time (according to the businesses' audited regulatory accounts), less depreciation calculated using a prescribed method and lives, adjusted for actual inflation. Indeed, under the Rules, the AER is required to produce a financial model that network businesses are required to apply when making this calculation.

19 Ibid, p.43.

cannot be met, Grid Australia considers it is important to step through how the framework actually operates and the incentives contained within it.

4.2 Incentive properties of the regulatory regime

When setting the level of a revenue cap the Rules require that actual capital expenditure undertaken in the previous regulatory period is included in the starting Regulatory Asset Base (RAB), and the RAB is projected forward incorporating a forecast of capital expenditure for the next regulatory period.

A return on the RAB – including the forecast of capital expenditure – is included in the revenue cap. That cap is then set for the regulatory period.[20] The incentive features of this process can be considered as having long term and short term components:

- First, by setting the revenue cap such that a return is provided on actual (past) expenditure and a forecast of efficient future expenditure, TNSPs are provided with an expectation that they will earn an appropriate return on capital expenditure. This provides the incentive and capacity for TNSPs to continue to invest in the networks. It is worth highlighting that as part of a revenue reset process, the revenue allowance is subject to AER approval based on its ex-ante assessment of prudency. In making this assessment the AER has regard to its own consultant reports, the views of stakeholders (including AEMO), and TNSP planning and other governance processes.

- Secondly, as the revenue cap is fixed for the period between reviews, TNSPs have an incentive to spend less if it is efficient to do so (subject to meeting offsetting obligations or incentives, such as service incentives) as the same level of revenue is earned irrespective of whether the forecast expenditure occurs or not.

The application of a revenue cap means that TNSPs are in fact penalised for every additional dollar that they spend – it follows, therefore, that they have an incentive to consider whether the relevant project can be deferred or delivered at lower cost. Notwithstanding this, as expanded upon below, Grid Australia notes that the incentive regime aims to ensure that service obligations are met at lowest sustainable cost. By incentivising TNSPs to look for ways to reduce the capital (and operating) expenditure required to deliver services to customers, a lower RAB is the outcome at the start of the next regulatory period which results in a lower cost base for customers.

Clearly, the incentive for TNSPs to reduce their expenditure needs to be balanced with either a requirement or incentive to ensure that an efficient level of service is provided to customers. Indeed, the inclusion of service obligations or incentives is premised on the effectiveness of the economic incentives to encourage TNSPs to minimise costs and avoid inefficient investment. This is currently achieved under the transmission framework

[20] Note, however, that 'pass throughs', contingent projects, or a 'ship wreck' situation can affect the total level of the cap during a regulatory period.

through a combination of reliability obligations (as set out in Chapter 5 of the Rules and in jurisdictional instruments) and through the service target performance incentive scheme. The combination of the financial incentives on TNSPs to minimise cost with the measures to ensure appropriate service delivery imply that:

- TNSPs have an incentive to meet their service obligations at the lowest cost, which includes to:
  - take account of information and analysis reasonably expected to be considered at the time of making the investment, which may adjust the project scope or its timing as necessary (the latter of which includes investing in smaller projects or schemes that may enable a major investment to be deferred);
  - select the lowest efficient cost investment that meets the required timeframe for delivery, including to adopt new technology or techniques as they become available;
  - employ non network options over network options where commercial benefits arise from the incentive arrangements;
  - use innovative work practices, improve outage coordination, and optimise the capital and operating work program; and
- TNSPs have an incentive to spend efficiently (both operating and capital) and improve their service levels where this generates a reward under the service target performance incentive scheme that exceeds the cost of that initiative.

Given these arrangements it is clearly not the case that TNSPs are merely rewarded for delivering more transmission assets.

Notwithstanding the remarks above, Grid Australia acknowledges that the potential may exist to refine the current incentive arrangements and is open to any new practical means of enhancing the incentive properties of the current regime. As previously indicated, the AEMC is currently conducting a Transmission Frameworks Review, which is the appropriate forum to address this issue.

4.3 Drivers of new investment

Grid Australia also rejects the suggestion in the Update Paper that transmission businesses have been 'gold plating' their networks in recent years (with the exception of inter-regional investments, where the opposite concern has been expressed).

Contrary to the Electricity Update Paper's suggestions, no evidence is presented that suggests the recent increase in the rate of investment is excessive. In contrast, the recent increase in investment (part of which merely reflects the substantial increase in materials costs as a result of the 'minerals boom') has been essential to ensure that the reliable and secure electricity supply that customers expect and is fundamental to the economy continues.

Indeed, the AER itself has recognised the need for increasing network investment in the future. In its 2010 State of the Energy Market Report, the AER identified the drivers for increases in forecast network investment, observing as follows:[21]

> *The key drivers for rising investment include:*
>
> - *More rigorous licensing conditions and other obligations for network security, safety and reliability*
> - *Load growth and rising peak demand*
> - *New connections*
> - *The need to replace aging assets, given much of the networks were developed between the 1950s and 1970s.*
>
> *Other drivers include changes to system operation due to climate change policies and the introduction of smart meters and grids*.

The AER also noted that each network has unique issues relating to its age and technology, its load characteristics, the costs of meeting demand for new connections, and its licensing, reliability and safety requirements.

[21] AER, *State of the Energy Market: 2010, December 2010*, pp.54-55.

5. Return commensurate with risk

- A commercial return for transmission businesses provides the incentive and capacity needed for future investment to be undertaken
- The current regulated rate of return parameters used reflect extensive and numerous reviews extending over the past 15 years of market evolution. The most recent 5-yearly review was concluded by the AER in 2009.
- The approach applied to estimate the cost of capital associated with electricity network businesses is highly consistent with conventional regulatory practice
- There is no justifiable reason for government owned network businesses to have a different cost of capital to privately owned businesses. Indeed, there are strong arguments to ensure they are consistent.

5.1 Electricity Update Paper findings

The Electricity Update Paper infers that a major cause of recent price increases is the rate of return earned by network businesses, which it asserts is excessive. It argues that there is little recognition that network investment is recouped with near certainty and is passed onto creditworthy retailers who recoup it from customers, and considers it illogical that:[22]

> *the discussion of returns proceeds as if this were a mixture of ordinary business equity and debt investment, earning normal commercial returns.*

It suggests that there is a need for the rules to relate the cost of equity and debt to the riskiness of the investments.[23]

The Electricity Update Paper further argues that where the business is government owned, the regulated rate of return exceeds the true underlying cost of finance to a greater extent than for a private owner, which it argues should be reflected in the rules.[24]

Grid Australia considers these observations to reflect a fundamental misunderstanding of the requirements of the regulatory regime, as well as being inconsistent with mainstream finance thought. The specific concerns are articulated in turn below.

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[22] Garnaut, R., *Garnaut Climate Change Review – Update 2011, Update Paper eight: Transforming the electricity sector*, March 2011, p.41

[23] Garnaut, R., *Garnaut Climate Change Review – Update 2011, Update Paper eight: Transforming the electricity sector*, March 2011, p.44

[24] Garnaut, R., *Garnaut Climate Change Review – Update 2011, Update Paper eight: Transforming the electricity sector*, March 2011, p.42

5.2 Need for a commercial return

First and foremost, Grid Australia emphasises that providing a commercial return on transmission investment (commensurate with the risk involved) is essential for TNSPs to have the capacity to attract the investment funds required to continue to provide the reliable and secure service that customers demand.

5.3 The requirements of the Law and Rules

In contrast to the assumption in the Electricity Update Paper, the regulatory regime does in fact require a return to be provided that is commensurate with the risk of the transmission investments. The National Electricity Law provides explicitly as follows:[25]

> *A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.*

In addition, the Rules provide that the rate of return should be determined as follows:[26]

> *The rate of return for a Transmission Network Service Provider for a regulatory control period is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the transmission business of the provider*

Moreover, when undertaking the five yearly review of the inputs or assumptions into the cost of capital, the AER is required to consider the following (amongst others):[27]

> *the need for the rate of return calculated for the purposes of paragraph (b) to be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing prescribed transmission services;*

Given these requirements, there is no basis for suggesting that the framework does other than to ensure that returns are provided that are commensurate with the risk involved. Indeed, when it last undertook its five yearly review of the parameters for the return on capital, the AER remarked as follows:[28]

> *Of particular relevance in relation to the rate of return, is that the [Weighted Average Cost of Capital] (WACC) be set at a level expected to be sufficient to*

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25 National Electricity Law, section 7(5).

26 National Electricity Law, Rule 6A.6.2B(b)

27 National Electricity Rules, Rule 6A.6.2(j)(1).

28 AER, *Final Decision, Electricity Transmission and the Distribution Network Service Providers, Review of the Weighted Average Cost of Capital (WACC), Parameters,* May 2009, p.12.

incentivise efficient investment in electricity network infrastructure, while not set too high so as to incentivise inefficient overinvestment in electricity network infrastructure. The AER considered that if it determined values and methods for individual WACC parameters that produce an overall regulatory rate of return that is expected to achieve this outcome, the AER will have exercised its power in a manner that will or is likely to contribute to the achievement of the NEO. In doing so, the AER also considered that, in respect of each parameter, it would have also had regard to the need to achieve an outcome which is consistent with the NEO.

In reviewing the individual WACC parameters, the AER had regard to a range of theoretical and empirical considerations and evidence, including that presented in submissions to the issues paper, and contained in expert reports commissioned by stakeholders and the AER. Having had regard to this range of considerations and evidence in reviewing the WACC parameters, the AER considered it has achieve the appropriate balance as discussed above.

5.4 Methods used to estimate the rate of return are conventional

The techniques that are applied to estimate a required rate of return for electricity networks reflect standard practice amongst finance practitioners and are also consistent with the practice of many regulators around the world. Indeed, it is also universal around the world for utility businesses to be considered as normal businesses that would be financed through a mixture of debt and equity, both of which demand a commercial return.

Grid Australia notes, however, that the discussion in the Electricity Update Paper appears to assume that there is no account taken of the relatively lower risk of regulated networks when estimating the cost of capital. This assumption is false. Under the Capital Asset Pricing Model – which is the technique that is used to estimate the cost of equity capital – the beta is the measure of the relative risk of an investment.

Currently the beta that the AER employs when stripped of the effects of financial leverage is 0.32, which compares to an average for the assets that are listed on the share market of approximately 0.70.[29] This means that electricity network assets are assumed to be less than half of the risk of the average business amongst those that are listed on the Australia Stock Exchange.

[29] The AER uses an equity beta of 0.80 for an assumed gearing level of 60 per cent debt to assets, which translates into an asset beta of 0.32 (0.8 x 40% equity). In contrast, the share market as a whole has an equity beta of 1, but an average level of gearing of approximately 30 per cent debt to assets, implying an asset beta of 0.70 (1.0x 30% equity)

5.5 Cost of capital for a government owned business

Grid Australia is surprised that the Electricity Update Paper claims that the costs of finance for government entities are lower than for privately owned entities.[30] This statement ignores the settled view in finance that the cost of capital is the same irrespective of whether an investment is undertaken by the private or public sector.

The Electricity Update Paper also appears to suggest that public sector projects are risk free because they can be financed through government borrowing at the risk free rate. However, this view ignores the fact that taxpayers would then bear a liability for providing a guarantee to the project, which is a real albeit unobserved cost of the project.

In addition, ensuring that prices for using networks reflect a commercial cost of capital where assets are government owned is also important for ensuring that the correct signals are provided for efficient decisions by generators and customers. In particular, artificially reducing the price of network services for state owned network businesses could cause customers or generators to alter their location decisions, even if to do so was inefficient from society's point of view.

Finally, policies in support of the principle of competitive neutrality were established as an integral part of the Hilmer competition reforms in the early 1990s and were subsequently endorsed by COAG. The Electricity Update Paper is at odds with the established principle of neutrality and a basis for reviewing this principle has not been clearly argued.

[30] Garnaut, R., *Garnaut Climate Change Review – Update 2011, Update Paper eight: Transforming the electricity sector*, March 2011, p.42

6. National transmission charging

- National transmission charging would have no direct influence on transmission investment decisions – it is not a relevant factor in the RIT-T and does not affect the financial returns to TNSPs
- Nevertheless, it is important that customers pay an efficient price for the assets they use
- The Rule change before the AEMC for a load export charge is an appropriate and proportionate response to ensuring efficient price signalling occurs between regions

6.1 Electricity Updated Paper findings

The Electricity Update Paper states that the costs of all new interstate transmission should be recovered nationally. This statement was based on the belief that the absence of a national system of transmission pricing is creating a barrier to interconnector investment, and that all users of power in the regions covered by the NEM would receive benefits from access to a smoothly operating market, wherever they are located within the market.[31]

6.2 Merits of Inter-regional charging arrangements

It is important to note at the outset that inter-regional charging does not factor into the economic assessment of a proposed investment at the RIT-T stage and therefore does not influence the investment decision in that respect.

In addition, the structure of prices that a TNSP sets does not affect its payoff from an investment, and hence inter-regional charging would not affect a TNSP's commercial incentives with respect to interconnection assets. At best, inter-regional charging has a second order impact on transmission planning and investment by potentially improving the efficiency of price signals to customers, thereby disciplining demand to efficient levels. However, the resulting impact in this instance is just as likely to be a need for less investment rather than more.

The need for inter-regional transmission charging was identified in the AEMC's review of the impact of climate change policies on the NEM. Following on from that review the MCE submitted a Rule change to the AEMC to introduce inter-regional transmission charging through a load export charge. The load export charge would reflect the flow of electricity from one region to adjoining regions. The level of the charge would reflect the costs incurred in the use of the transmission network in the region to conduct electricity to an adjoining region, therefore, the charge should be calculated as if the relevant

[31] Garnaut, R., *Garnaut Climate Change Review – Update 2011, Update Paper eight: Transforming the electricity sector*, March 2011, p.34.

interconnection with the adjoining region was a load on the boundary of the region. A load export charge is relatively low cost to implement, but facilitates customers that use network assets in an adjoining region to pay for them.

The proposed alternative of a national charging framework, on the other hand, would be particularly complex and costly to implement. Given a load export charge achieves the main aim of signalling the cost of network assets customers use in adjoining regions, it is not clear that the a national charging framework would achieve benefits in excess of the costs of implementing and applying such an approach.

7. Merits review

- Merits review is a key component of an independent and well-functioning regulatory regime
- It is particularly important for electricity transmission businesses given the long-lived nature of transmission assets and their dependence on regulatory outcomes for revenue
- A full merits review, as proposed in the Electricity Update Paper, would significantly increase the costs and time of undertaking a review without a commensurate benefit
- The appeal decisions to date highlight the importance of a cost effective merits review process being in place. The majority of decisions to date have found that, based on the material before the AER at the time of its original decision, the AER had erred to the material disadvantage of the appellant. Indeed, even the AER has conceded that errors have been made, in particular with respect to the value of some parameters for the cost of capital.
- The particular form of merits review now in operation was deliberately designed by the MCE to limit the scope of appeals to material before the AER at the time of the AER's decision. It is also designed to provide barriers to bringing forward non-material claims

7.1 Electricity Update Paper findings

The Electricity Update Paper questions whether the existing appeals process is too generous to the businesses. This question appears premised on the view that the appeal of a decision is free to the firm and without a realistic possibility of an adverse outcome.

Therefore, it is claimed that appeals automatically follow all regulatory determinations. The Paper claims that this burdens the regulator's decision making in favour of the businesses. In response the Electricity Update Paper suggests that any appeal should require a reopening of the whole of the determination so that the appellant would thereby accept the risk of an unfavourable outcome.[32]

7.2 The merits of merit review

While merits review has only been a component of the transmission framework for a relatively short amount of time, it is a key aspect of an independent and well-functioning regulatory regime. Merits review ensures that regulators are accountable for their decisions, thus providing pressure for balanced, consistent and correct decisions. This

[32] Garnaut, R., *Garnaut Climate Change Review – Update 2011, Update Paper eight: Transforming the electricity sector*, March 2011, pp.42-43

view is supported by the Expert Panel on Energy Access Pricing which concluded that it is desirable to provide merits review of decisions of the AER in relation to price and revenue controls, observing as follows:[33]

> *The Panel notes that appropriate provision of merits review increases the confidence of all parties in a regulatory system, but that merits review processes that are not appropriately specified can lead to incentives to game the regulatory system and as a result delays and considerable cost.*

The Panel recommended a model for merit review that addressed its concerns about the potential for parties to withhold important information from the regulator, but make it available in an appeal (the 'game'), which is the model that was adopted in the National Electricity Law.

The consequences of poor regulatory decision making are high for transmission businesses. The long-lived nature of transmission assets, and the dependence on regulatory outcomes for revenue, mean that poor regulatory decisions will have an enduring impact on transmission investment and operation. Ultimately, poor regulatory decision making would be to the detriment of customers.

7.3 The merits of the current merits review model

The existing merit review provisions were designed carefully to provide for a low cost and expeditious process. It allows both the businesses and customers to appeal a decision. It can only be activated in situations where the appellant first demonstrates an error on the part of the AER, is limited to those matters where an error is demonstrated, is also limited to matters that are material issues, and can make use only of the information that was before the AER during the review.

In contrast, the model that has been proposed in the Electricity Update Paper would involve a full rehearing of every element of the decision. In practice this would mean that the review panel would be required to repeat the process undertaken by the AER and make the revenue determine again in its entirety. Such a process would significantly increase the costs and time taken to undertake a review. These costs would ultimately be borne by customers.

Grid Australia notes that the Standing Committee of Officials when considering options for review of regulatory decisions excluded the option of a full merits review from its analysis. The reason for this was the costs and time involved in undertaking a full review of regulatory decisions.

[33] Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p.92

7.4 Issues with merits review

Grid Australia is aware of a perception that many more appeals have been lodged in response to AER decisions than policy makers may have expected and that network businesses have been successful a greater proportion of the time than expected.

Any assessment of the workings of the current merits review model must include a balanced review of the matters that were taken to appeal and the decisions of the Australian Competition Tribunal.

Network businesses do not have an unencumbered right to require the Tribunal to rehear matters, but instead bear the onus of having to actively demonstrate an error on the part of the AER. In addition, of the matters where the businesses have been successful, a balanced review would show that the vast majority were matters where the error the AER made was obvious to any independent party, but at the same time material. Denying a low cost remedy in such cases has the potential to diminish materially the investment environment for regulated energy assets.

Lastly, one of the arguments in the Electricity Update Paper is that allowing only part of a determination to be reopened is somehow wrong and would leave the final determination unbalanced in some way. This would seem to reflect an implicit assumption that an error that is adverse to a network business would generally be offset by some other error that was favourable, but that the overall package is somehow reasonable.

This last belief reflects a misunderstanding of the process and decision that a regulator makes when determining prices. A regulator has no way of testing whether the overall package that is reflected in a determination is appropriate, and no such test is invited under the Law and Rules. Rather, a regulator makes a whole series of constituent decisions, with making correct constituent decisions being the only means of ensuring a correct overall result. Thus, to the extent that part of a determination involves an error, the only conclusion that can be drawn is that the overall determination is in error, and that the specific error identified should be remedied.

8. Economic basis for planning standards

- Consistent with the AEMC's recommendations, planning standards should be determined on an economic basis, but expressed deterministically
- Also consistent with the AEMC's recommendations, planning standards should be determined by a party that is independent of the TNSPs
- Expressing economic planning standards in a deterministic form ensures transparency of service performance by TNSPs and, thus, supports clear accountability for performance.

8.1 Electricity Update Paper findings

The Electricity Update Paper notes that the setting of standards and service requirements has not been subject to institutional or regulatory reform. It claims that rather than being based on a probabilistic cost-benefit approach to reliability, most States tend to use a relatively crude and deterministic approach to dictate reliability requirements. It claims that this leads to higher standards being imposed than would be the case under a probabilistic approach.[34]

8.2 Application of Planning Standards

The primary objective of planning standards is to ensure that customers are able to receive a reliable supply of electricity. The standards are typically set to ensure that peak demand can be met with an appropriate level of contingency should some credible event occur. Typically there is a high level of contingency applied for electricity network assets. This reflects the costs of service interruptions, noting that community and business have a very low tolerance of electricity network service failures.

Grid Australia supports planning standards that are determined on an economic basis. Doing so ensures that a trade-off can be made based on the significance or criticality of the load centre and the costs of providing reliable supply. However, Grid Australia considers that there are significant advantages in expressing these economic outcomes in a simple, deterministic form. This is because of the transparency that deterministic standards allow. This position is consistent with the findings of the Reliability Panel, which were accepted by the AEMC as part of the Transmission Reliability Standards Review. In that Review the AEMC found that it is appropriate for deterministic standards to apply when they are economically derived.[35]

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[34] Garnaut, R., *Garnaut Climate Change Review – Update 2011, Update Paper eight: Transforming the electricity sector*, March 2011, p.13.

[35] AEMC, *Transmission Reliability Standards Review, Final Report to MCE*, 30 September 2008, p.vi

In addition, Grid Australia supports the AEMC finding in its review that planning standards should be set by a jurisdictional authority that is separate from TNSPs. This ensures there is sufficient independence and transparency in the process.

The Electricity Update Paper appears to overlook the important fact that all of these elements are features of the current framework in South Australia, where the transmission network business is privately owned. This provides a working model which could be extended across the NEM under the AEMC's recommended framework.

Response to NSW Independent Pricing and Regulatory Tribunal—Draft report—Changes in regulated electricity retail prices from 1 July 2011

12 May 2011

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1. Overview

The Energy Networks Association (ENA) welcomes the opportunity to respond to the Independent Pricing and Regulatory Tribunal's (IPART's) *Draft Report—Changes in regulated retail electricity prices from 1 July 2011* (Draft Report).

The Draft Report proposes increases in regulated electricity prices effective from July 2011, and examines the range of factors which are currently driving increased electricity prices in New South Wales. The Draft Report also goes beyond an assessment of permitted increases in regulated retail charges to make a number of recommendations on the national regulatory policy framework governing electricity network charges, recommending a review of these arrangements to address four specifically claimed deficiencies in areas of Chapters 6 and 6A of the *National Electricity Rules* (NER).

These four claimed areas of deficiencies cover the 'burden of proof' facing the Australian Energy Regulator (AER) in making determinations on network cost forecasts, the design of merit appeal processes, the degree of regulatory guidance in setting regulated returns and the 'ex ante' capital expenditure approach adopted in the NER.

Energy network businesses are concerned that significant elements of IPART's assessment of these aspects of the NER and the broader regulatory framework appear to not to be based on sound analysis. In particular, several assumptions made in the analysis in the Draft Report do not to take into account critical provisions of the *National Electricity Law* and *National Electricity Rules* which are directly relevant to the issues discussed by IPART. In addition, several criticisms made of the regulatory regime also do not accord with evidence from the actual experience of the application of the NER by the AER.

Energy network businesses also consider that the conclusions in the IPART Draft Report do not adequately reflect the full range of regulatory and public policy considerations which have led to the deliberate design choices recently made by Australian governments and the Australian Energy Market Commission in the modernisation of the *National Electricity Rules* and associated legislative framework. It follows from this, and from the Ministerial Council on Energy's key policy goals for energy market reforms which led to the recently revised framework, that the network sector does not consider that a review of current regulatory arrangements in the areas outlined by IPART is warranted. This view is reinforced by the fact that promotion of a stable regulatory environment, which supports the capacity of network businesses to both efficiently finance and make significant sunk capital investments on an ongoing basis, is clearly in the interests of current and future energy consumers.

Recommended approach

Based on its assessment of the Draft Report, ENA recommends that the Tribunal should:

1. engage in an open and constructive dialogue with participants in the network sector to gather more direct evidence on issues around the contents and interpretation of the NER; and
2. review its analysis of the impact of the *National Electricity Rules* on network prices and the associated recommendation calling for a review of these arrangements.

2. Background

ENA is the peak national body for Australia's energy networks which provide the vital link between gas and electricity producers and consumers. ENA represents gas distribution and electricity network businesses on economic, technical and safety regulation and national energy policy issues.

Energy network businesses deliver electricity and gas to over 13.5 million customers, employ more than 40 000 people and contribute approximately 1.25 percent to Australia's gross domestic product. Energy is delivered across Australia through approximately 48 000 km of transmission lines, 800 000 kilometres of electricity distribution lines and 81 000 kilometres of gas distribution pipelines. Energy network businesses are valued at over $65 billion and annually undertake an average investment of approximately $12 billion in network operations, reinforcement, expansions and greenfield extensions.

3. National economic regulatory rules

The Draft Report released by IPART makes a number of observations about the design and operation of national economic regulatory rules applying electricity and gas networks. Each of these observations is addressed in turn in the following sections.

3.1 The 'burden of proof' on the regulator under the NER

The Draft Report posits that the AER is faced with an '*unusually high'* burden of proof in rejecting or amending regulated businesses' spending proposals. Energy network businesses do not consider that this is an accurate characterisation of either the terms of the NER, or empirical evidence from the operation of the Rules by the AER.[1]

The AER has recently approved, after lengthy, public, and detailed deliberations in accordance with the Rules, substantial increases in capital and operating expenditure in some jurisdictions. This does not, however, provide evidence that the AER lacks sufficient discretion under the NER to reject or amend expenditure proposals. Rather, it is evidence that an independent national energy regulator operating under a recently modernised regulatory framework has satisfied itself that significant increases in network investments are required to promote the long-term interest of consumers in the safe and reliable delivery of regulated electricity services.

A balanced assessment of the design and operation of the 'regulatory package' put in place by the Australian Energy Market Commission (AEMC) and the Ministerial Council on Energy (MCE) in relation to the regulation of networks, as well as the terms of the rules themselves, do not support IPART's view that the burden of proof is set inappropriately high.

3.1.1 Policy design underlying the 'fit-for-purpose' regulatory model

Both the MCE and the AEMC carefully considered the issue of the appropriate level of discretion in considering proposed expenditure in the design phases of current energy regimes, including the trade-offs and risks of both highly prescriptive and highly discretionary approaches. Their judgements on these issues were further informed by a series of comprehensive and influential expert reviews on appropriate approaches to access pricing, including the Productivity Commission *Review of the National Access Regime* and *Review of the Gas Access Regime*, the Prime Minister's Export Infrastructure Taskforce review, and the report of the MCE's Expert Panel on Energy Access Pricing.

The electricity network regulatory rules thus reflect a carefully designed 'fit-for-purpose' model under which the Ministerial Council on Energy and AEMC provided appropriate and tailored levels of discretion to accept or reject individual elements of regulatory proposals, guided by specific criteria, principles and the energy law objectives. Both the AEMC in its development of a revised Chapter 6A for the *National Electricity Rules* relating to transmission services and the MCE in its adoption of revisions to Chapter 6 of the *National Electricity Rules* covering distribution networks emphasised that these rules were intended to provide the AER with clear and unambiguous scope to reject 'inflated' or unrealistic expenditure proposals.[2] This is outlined clearly by the AEMC in its final determination in respect of the Chapter 6A electricity transmission revenue rules:

> The Commission believes that the subject of the regulation – the forecast capital expenditure and operating expenditure for substantial, highly complex and technical infrastructure for a five-year period is not a matter that is amenable to the level of precision and confidence that would enable one to sensibly say there is one correct or "best" figure. It considers that Rules that could be interpreted in that way are likely to result in a heightened risk of regulatory error. Equally the Commission does not intend that the Rules contemplate such a range of permissible outcomes that there is a risk of inherent bias toward higher amounts. Having regard to these considerations the Commission has elected to adopt a decision rule which requires the AER to accept the TNSP's proposal if it is satisfied that the amount "reasonably reflects" efficient and prudent costs based on realistic estimates of forecast demand and cost inputs.[3]

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[1] It is also noted that the concept of 'burden of proof' is not strictly applicable to administrative decision-making. The discussion below assumes that IPART uses the term more loosely in reference to the scope of the AER's discretion to reject elements of a regulatory proposal.

[2] Australian Energy Market Commission *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No.18*, November 2006, p.33 and Table 1 - *SCO Response to stakeholders comments on the exposure draft of the National Electricity Rules for distribution revenue and pricing (Chapter 6)*, p.25-28

[3] AEMC (2006), p.52

This makes clear the policy intent of the AEMC to avoid regulatory allowances including inflated or inefficient levels of expenditure, as well as illustrating some of the policy considerations that led both the MCE and AEMC to prefer a 'fit-for-purpose' regulatory model with tailored levels of regulatory discretion.

3.1.2 Errors and omissions in analysis of NER obligations

The IPART Draft Report does not accurately reflect the actual nature of the NER criteria for decisions on operating and capital expenditure forecasts. Under this framework, the AER is not obliged to 'prove' any affirmative case, as suggested by IPART. Rather, the AER is required to form a view as to whether it is satisfied that a networks' forecasts in its regulatory proposal meet the operating or capital expenditure criteria contained in the Rules. If the AER is not satisfied, it is required to derive a forecast expenditure which is consistent with the NER and substitute it for that put forward by the network business.

Key elements of the NER which critically affect the scope of AER discretion are incompletely reflected in, or omitted completely from, the IPART analysis. For example:

- the AER is explicitly forbidden from accepting operating and capital expenditure forecasts where it is not satisfied the spending meets the operating expenditure criteria (See NER Cl.6.5.6 (d));
- the AER is provided with a wide range of factors (10 each in relation to capital and operating costs) to have regard to in reaching a determination on cost forecasts (See NER Cl.6.5.6 (e) (1)-(10));
- these factors include scope for the AER to have regard to its own internal analysis, assessments of benchmark efficient costs, and past actual expenditure, providing a number of bases under which in applying the rules the AER may reject or amend forecast expenditures; and
- the issue of whether the NER expenditure provisions created a 'burden of proof' was subject of detailed consideration and advice from Senior Counsel to the AEMC in the drafting of the relevant rules – this advice confirms no such 'burden' arises for the AER.[4] Further, the review body, the Australian Competition Tribunal has subsequently provided guidance that again makes clear that the AER's duties under the NER are established by direct reference to rules provisions, rather than in the context of any overarching 'burdens of proof'.[5]

The claim by IPART that the AER lacks sufficient regulatory discretion to conduct its task under the regulatory framework is also inconsistent with the empirical evidence since the commencement of the operation of revised electricity framework.

In none of 10 major electricity network pricing determinations to date has the AER expressed concern that the operation of the NER limits its capacity to deliver decisions that promote the *National Electricity Law* objective. In contrast, the AER has routinely amended proposed capital and operating cost forecasts according to its interpretation of the spending that is consistent with the NER. In fact, the only (rare) instances of Australian regulators accepting without amendment proposed cost forecasts have occurred outside of the NER framework.

Were the proposition true that a 'burden of proof' has been made inappropriately high by the introduction of revised NER in 2006, then two significant trends could be expected to be observed:

- First, larger average reductions between proposed expenditures and allowed expenditures under previous State-based regulatory approaches compared to regulation by the AER under the revised NER; and
- Second, potentially systematic differences in the average level of operating and capital cost reductions in gas compared to electricity regulatory decisions, given that the Natinoal Gas Rules (NGR) provide the AER with discretion to reject or amend spending not based on the 'best forecast' or estimate possible in the circumstances (Rule 74, see also Rule 79 and 91)

From an examination of decisions currently in force, however, what is actually seen is very mixed evidence with no clear support for either of these expected trends. In contrast, what can be observed is:

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[4] AEMC (2006), p.52

[5] *Application by Ergon Energy Corporation Limited [2010]* ACompT 6, [51]

- Larger percentage reductions in proposed capital expenditure programs by previous State-based jurisdictional regulators, but percentage reductions by the AER in operating expenditures which are nearly **double** the size of those from jurisdictional regulators (7.1 per cent compared to 3.7 per cent)

- Larger reductions in capital expenditure allowances in gas than in electricity (10.5 per cent compared to 9.9 per cent) , but **smaller** average reductions in relation to operating costs (4.2 per cent compared to 4.9 per cent)

Whilst the sample of network regulatory decisions in force is relatively small (at 20 decisions), neither of these observed findings provide supporting evidence for IPART's contentions. Empirical evidence does not support the claim that the regime has allowed inflated or inefficient expenditure to be accepted.

3.2 Operation of network appeal processes

The appeal process under the *National Electricity Law* is a form of limited merits review which like other administrative and judicial appeal mechanisms focuses on the issues in dispute between the two parties. This is the result of a deliberate policy decision taken by the Ministerial Council on Energy to establish a form of review that was timely, efficient, and focused on improving the quality of primary regulatory decision-making and correcting regulatory errors.[6]

Providing the appeal body a wider remit in the manner suggested by IPART to review the decision at large and remake elements of the decision outside of the areas in practical dispute would alter the model to a form of full *de novo* review. This development is at odds with the recent policy design decisions of both the Ministerial Council on Energy in respect of electricity and gas regimes, and the Council of Australian Government in respect of the generic national access regime operating under Part IIIA of the *Competition and Consumer Act*.

Merits review mechanisms continue to be considered elements of modern best practice access frameworks, a point most recently reinforced by the independent Productivity Commission's ongoing review of the urban water sector.[7] The Productivity Commission notes in particular the effect of diminished accountability of regulators and increased scope for regulatory errors where review mechanisms are constrained. It also notes the role merits review plays in safeguarding the rights of those regulated, and encouraging the identification and correction of ineffective regulation.

It is incorrect that the Australian Competition Tribunal is prohibited from examining the broader consequential effects of the issues in dispute in energy appeals. In fact, the AER has wide powers to raise, as a review related matter, outcomes or effects which consequentially arise from the matters in dispute.[8] The appeals provisions in the national energy laws provide that the Tribunal does not reconsider the entire AER decision because as a matter of sound regulatory policy each constituent element of the AER's decision is required to be reasonable and free of material errors. A significant benefit of this approach is that there is transparency as to each element of a decision, promotion of predictability and replicability of decisions, avoiding unaccountable 'black box' decision-making. As IPART appears to be basing its analysis on incorrect assumptions about the actual terms and operation of the appeal framework, it follows that its conclusion that a bias is thereby created in favour of higher or inefficient prices cannot be sustained. Rather, a limited appeal mechanism creates incentives for reasonable and soundly based regulatory decision-making, free from regulatory errors, and the efficient resolution of merits-based reviews.

IPART suggests that the current appeals arrangements lead to network businesses not being required to consider whether they could end up 'worse off' as a result of initiating a review. This proposition is incorrect. The decision to commence an appeal under the current framework needs to take account of substantial potential risks and costs. Contrary to IPART's assertion, a network business does face the real prospect of adverse outcomes from initiating a review through the capacity of a range of parties and interveners to raise additional review matters which have the potential to lead to material downward revisions to allowable revenues.[9] This creates the potential for other wider elements of the decision to be opened for review, to the potential material disadvantage of the network business. In addition, Ministers of participating jurisdictions may intervene without leave.

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[6] MCE *Decision on Review of Decision-Making in the Gas and Electricity Regulatory Frameworks*, May 2006, p.3

[7] Productivity Commission – *Australia's Urban Water Sector – Draft Report*, 13 April 2011, p.92 and p.290

[8] National Electricity Law, s.71O (1)(b)

[9] National Electricity Law, s.71M- O

These combined circumstances create an environment in which a decision by a business to appeal must be carefully balanced against the potential for other additional review issues to be pursued by AER, the Minister, consumer representative bodies, and end users. Additionally, IPART's analysis does not account for the substantial direct and indirect financial costs of a review application and process. The analysis also ignores broader impacts of the review process that network businesses must consider, including diversion of senior commercial management resources, and, potentially, adverse impacts on the ongoing working relationship with the regulatory body concerned.

The alternative raised by IPART of providing for judicial review of decisions only does not meet the objectives set by the Ministerial Council on Energy for a sound and effective review mechanism. [10] The option of providing judicial review only to decisions was rejected in the MCE's policy decision on review arrangements because it would not permit the correction of as full a range of likely regulatory errors with adverse societal consequences as a system which featured merits-based review. In making this decision, the MCE recognised that rather than being substitutes, merits and judicial review are in fact discrete but complementary mechanisms.

3.3 Determining regulatory returns under the NER

The *National Electricity Rules* provide guidance to the AER in determining regulatory returns which is significantly more detailed than applies under legislative frameworks under which IPART operates. This approach, however, is the deliberate result of a significant modernisation and updating of the design of regulatory frameworks applying to networks by MCE and AEMC from 2005-07.

A core objective of this process of policy reform was establishing a regulatory framework which promoted the national electricity and gas objectives, and provided increased levels of investment certainty by improving the quality and predictability of economic regulatory decision-making. [11] As part of this reform process, the AER effectively assumed responsibility for network revenue regulation from jurisdictional regulators such as IPART from 2008 onwards. This has arguably led to a significant divergence between the frameworks typically applied by jurisdictional regulators and the recently adopted frameworks in energy. This fact, however, does not establish that these modernised national regulatory frameworks which are distinct from those applied by bodies such as IPART are inferior or, as claimed, unduly prescriptive. Rather, the deemed consistency of national energy access regimes with a set of best-practice principles set out in revised national competition agreements such as the 2006 *Competition and Infrastructure Reform Agreement* suggests that the energy access regimes display features which are more consistent with the best practice regulation of significant infrastructure than a range of State-based frameworks IPART currently applies. [12]

The level of guidance in Chapter 6 and 6A of the *National Electricity Rules* reflect a policy decision on the part of MCE, the AEMC and a wide range of industry and others stakeholders to 'codify' some elements of widely accepted regulatory practice to enhance the predictability and replicability of regulatory decision-making, to enhance investment certainty. The claim that this codification has resulted in an overly prescriptive approach which leads to excessive returns, however, cannot be sustained on the basis of the *National Electricity Rules*, or their application and interpretation by the AER for several reasons.

First, the NER does provide for appropriate scope for the AER to appropriately adjust the WACC for changing market circumstances at the time of the network pricing decision. Under the NER, the cost of capital is set on a forwarding looking basis with market varying parameters set to reflect the return required by investors in commercial enterprise with a similar nature and sets of risks as a network business. In both the transmission and distribution rules, the debt risk premium, and risk free rate underpinning the WACC are required to be adjusted to reflect market conditions. In the case of distribution, both the network business and the AER are also permitted to seek adjustments to other WACC parameters (such as equity beta or market risk premium) which are typically varied less frequently in response to persuasive evidence that justifies the adoption of different values. In either case, network businesses bear the downside risks where the actual cost of financing exceeds the benchmark WACC assumption.

Over the period 2009 to 2011, the AER has applied a number of changes to equity beta assumptions of networks businesses in distribution network determinations, as well as varying the market risk premium to take into account

[10] MCE (May 2006) p.13-15

[11] See for example *Australian Energy Market Agreement*, Clause 2.1

[12] See Council of Australian Governments *Competition and Infrastructure Reform Agreement 2006*, Clause 1.13

an increase in the risk premium due to the GFC, and more recently, a claimed easing of adverse capital market conditions. It is noted that over this same two year period, IPART itself has not varied its key market risk premium assumption, despite generally operating under frameworks featuring lower levels of direct prescriptive regulatory guidance on cost of capital issues. Similarly, IPART has an overall record of stability in relation to its equity beta assumptions for regulated utility businesses that does not differ significantly from the AER (which in fact, adopted a sharper reduction in its beta assumption in its 2009 generic cost of capital review than has been typical of the majority of IPART's decisions). In the case of electricity transmission, values for parameters such as the market risk premium and equity beta are applied mandatorily between five yearly cost of capital reviews. As noted above, this achieves the policy goal of enhancing regulatory and investment certainty, and provides a similar degree of consistency as IPART itself has chosen to adopt in relation to these same parameters.

Second, the AER has made clear in a series of electricity network decisions, and the generic cost of capital review itself, that the application of the current NER does not provide for, or intend, a 'mechanistic' setting of a WACC value. The AER has instead emphasised the role of judgement and discretion under the broad guidance provided by the national electricity objective and revenue and pricing principles.

Third, the codification of some cost of capital parameters merely builds on previous initiatives voluntarily undertaken by the ACCC itself to provide greater guidance and certainty over its approach to network revenue regulation. This is evident from the self-initiated preparation by the ACCC of the *Statement of Regulatory Principles for the Regulation of Transmission Revenue* (SRP) which was developed, revised and issued by the ACCC over the period from 1999-2004. In significant areas, the NER builds on and adopts the outcomes of the SRP, with the principal difference under the new market and institutional governance arrangements being that the NER's codification is now open to challenge, and potential rule changes from a wider range of market stakeholders than the ACCC's previous statement.

3.4 Approaches to adjusting the asset base for capital expenditure

The NER adopts an *ex ante* approach to the addition of capital expenditure to the regulatory asset base, meaning actual capital expenditure undertaken to assist in the delivery of regulated services is recovered from current and future consumers.

IPART appears to be suggesting a reversion to a previous regulatory approach know as 'ex post' assessment, under which a regulator is provided wide discretion to review past expenditure and disallow recovery of actual network investments made on a retrospective basis. This approach is at odds with the policy choices adopted by ACCC, the Ministerial Council on Energy and the AEMC in their application and design of third party access regimes over the past decade. *Ex post* approaches to capital expenditure are subject to wide criticism in regulatory policy terms due to the:

- capacity for increased regulatory risk and uncertainty for service provider to more than offset any potential efficiency benefits;
- intrusive nature of applying the framework, requiring a regulatory body to effectively 'second guess' on the basis of information not before the network business at the time of the investment, the prudency of the investment; and
- potential consequences of the 'chilling impact' of such reviews on undertaking efficient investment underpinning the safe, reliable and efficient delivery of network services.

The ENA would encourage IPART and any subsequent review body to closely examine the full range of regulatory policy considerations which have to date led the ACCC, MCE and AEMC to reject the *ex post* approach to capital investment assessment. A balanced review of this matter should likewise consider the range of commonly identified deficiencies in *ex post* approaches which led to a broad consensus in favour of the adoption of superior *ex ante* approaches in revised electricity access frameworks.

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12 May 2011

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