REPORT

Prepared For:

Energy Reform Implementation Group

A Report to ERIG on Transmission in the National Electricity Market

Prepared By:

CRA International

Level 31, Marland House

570 Bourke Street

Melbourne Vic 3000, Australia

Authors: E.G Read, M.T Thomas, G H Thorpe,

DISCLAIMER

CRA International and its authors make no representation or warranty as to the accuracy or completeness of the material contained in this document and shall have, and accept, no liability for any statements, opinions, information or matters (expressed or implied) arising out of, contained in or derived from this document or any omissions from this document, or any other written or oral communication transmitted or made available to any other party in relation to the subject matter of this document. The views expressed in this report are those of the authors and do not necessarily reflect the views of other CRA staff.

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

CRA International Pty Ltd (CRA) has been engaged by the Department of Tourism Industry and Resources on behalf of the Energy Reform Implementation Group (ERIG) to advise on aspects of the incentives within the regulatory and market arrangements for Transmission Network Service Providers (TNSPs) within the National Electricity Market (NEM). In parallel ERIG has commissioned Firecone Ventures Pty Ltd to consider the potential for changes to arrangements for governance of the transmission sector within the NEM. Their report is available as a companion document.

1.1. INCENTIVE ELEMENTS IN THE REGULATORY REGIME FOR TRANSMISSION

The regulatory regime for transmission within the NEM incorporates provisions that shape investment and performance standards and incentives and includes:

- A revenue cap set for a minimum regulatory control period of five years that creates incentives for capital investment and expenditure management;
- A self-administered "Regulatory Test" involving stakeholder consultation by TNSPs prior to major capital expenditure;
- Performance standards within a national economic regulatory framework in parallel with standards for service and performance set by each jurisdiction;
- Provisions that allow depreciation adjusted amounts for all capital expenditures incurred in the previous regulatory period to be rolled into the asset base for the next period and hence allow recovery of that capital expenditure and a return on that amount from the start of the next period, reducing most of the risk to the TNSPs arising from the need to invest; and
- Provisions that allow benefits arising from operating cost reductions within a regulatory period to flow to network owners beyond the current regulatory reset period rather than have those benefits "clawed back" and transferred to customers at the first possible reset opportunity.

The broad regulatory and governance arrangements of the NEM produce three types of incentives that affect investment and operating decisions of TNSPs through:

- Physical performance requirements of plant and equipment under both jurisdictional and national market regulatory regimes;
- Financial incentives within the economic regulatory arrangements relating to capital and in particular operating cost savings; and

- Reputation risks for TNSPs, in that the actions of a TNSP may trigger revisions to the regulatory regime and/or reduce TNSP credibility during regulatory processes and within the industry generally.

The materiality of financial incentives varies between jurisdictions and continues to evolve. At the same time the design of incentive regimes is complex and ultimately is a matter of judgement about the right level and mix of capital and operating incentives. The AEMC has only just completed a review as part of its consideration of the transmission revenue requirements in the National Electricity Rules (NER) and we do not see that it is our role to revisit that judgement within the current structure.

Standards for the physical performance of networks imposed by jurisdictional authorities vary across jurisdictions, and in some cases involve financial penalties for failing to meet the imposed standards. TNSPs have indicated that these obligations can dominate their investment and operational decisions.

Overall the regime provides a combination of incentives on capital and service standards intended to restrain inefficient capital expenditure and encourage efficient operation. The most recent changes made by the AEMC will ensure that TNSPs recover their capital investments (adjusted for depreciation) and have the opportunity to earn the approved rate of return over time on those investments. Allowance for any capital investments not already reflected in the regulatory asset base will enter the asset base automatically at the subsequent regulatory reset. As a result, there is an incentive for TNSPs to reduce unnecessary capital expenditure but this that weakens over the course of each regulatory cycle. As a result of the overall design the nett incentive is relatively weak overall as a TNSP is guaranteed recovery of depreciation adjusted capital and earn a return on its investments with at most a delay of five years.

Incentives related to the physical performance of networks are loosely linked to associated market-wide impacts under typical conditions. Although the AER intends to progressively develop these incentives to more tightly link performance to market impacts. The AEMC's most recent changes have increased the incentive to meet service standards from 1% up to 5% of TNSP revenue. As a result TNSPs will have an incentive of the order of the economic cost of possible increases in generator dispatch costs due to a network outage under typical market conditions, but in general much less than the impact on market prices.

Government-owned participants must also balance the intangible impact of the obligations and expectations that their ultimate owners may have on wider government policy objectives against their commercial obligations as credible independent participants. These impacts are difficult to assess, but they nonetheless exist.

The arrangements do not involve explicit *ex ante* approval, or *ex post* assessment, of actual expenditures once a revenue cap has been set and therefore place significant faith in the process of consultation with stakeholders and on how the TNSPs respond to stakeholder input.

1.2. CONCERNS

We have four primary concerns with the existing incentive arrangements:

- The process a TNSP must follow before investing in significant individual augmentations involves considerable effort to consult but provides little direct discipline on the TNSP. The success of the arrangement is heavily dependant on the TNSP-conducted stakeholder consultation processes within the Regulatory Test and the threat of a dispute under the NER. Outside of this process there is limited or only indirect review of specific investment decisions;

- The focus of review and evaluation that does occur is on specific assets or projects, whereas efficient network development is often linked to broader and longer-term programmes for development;

- The formal regulatory arrangements are relatively weak in relation to the development of inter-regional links. Jurisdictional obligations are oriented so that TNSPs place a higher priority on state-based reliability provisions (with state boundaries corresponding reasonably well to NEM regional boundaries, as such boundaries remain well aligned with state borders)[1]; and

- The Regulatory Test itself is worded in a way which does not create confidence about competitive neutrality, and is structured in such a way as to create essentially arbitrary distinctions between projects yielding ”market” vs “reliability” benefits, private vs public benefits, and forces projects to be assessed entirely under one heading or another. In practice projects may yield benefits in more than one category.

There are no specific requirements covering inter-regional reliability standards. Consequently, under present arrangements, inter-regional proposals are likely to be evaluated under the market benefits limb of the regulatory test. Reliability-related benefits of inter-regional proposals are therefore likely to be under-valued or ignored.

The introduction of the requirement for NEMMCO to develop the Annual National Transmission Statement (ANTS) within the NER has considerably enhanced the generally available information about the effect of potential network developments. However, publication of the ANTS is an obligation on NEMMCO. The ANTS is not incorporated into the formal regulatory process.

---

1 There is, however, an opportunity cost to TNSPs in not pursuing an inter-regional investment and TNSPs may be said to face “reputation” risk if they do not pursue opportunities with potential market benefit. The Annual National Transmission Statement now provides information about the potential for inter-regional augmentation.

,,

The lack of a formal connection between the ANTS and other transmission-related regulatory processes is potentially problematic. A TNSP may choose to link them in cooperation with adjacent TNSPs in their Annual Planning Reviews, but this linkage is not assured, nor would it necessarily be optimised for the full range of potential inter-regional investment opportunities.

Each of the TNSPs maintain their own planning arrangements and although they may decide to cooperate, not all augmentations will be mutually beneficial to adjoining TNSPs, nor will augmentations that provide market benefit necessarily be the most beneficial to the TNSP of the various proposals that the TNSP is able to consider. Assessments of the materiality of these impacts depend on hypothetical generation investments that may be economic as a result of alternative transmission development paths. However, there are examples where, *prima facie*, a mismatch exists between inter and intra jurisdictional developments.

1.3. CONCLUSIONS AND RECOMMENDATIONS

1. Irrespective of any structural or process changes developed in parallel with this report, the focus of arrangements for transmission, and in particular the Regulatory Test, could be improved by:

- Enabling them to deal more consistently and even-handedly with proposals involving combinations of transmission, generation, demand side or ancillary service elements;
- Dealing jointly with market and reliability benefits;
- Clearly shifting the focus of the meaning of "interconnection" from an element that physically joins the networks of adjacent TNSPs to the network infrastructure that links adjacent pricing regions of the market – essentially between the market pricing nodes. That infrastructure should include all network elements that affect the capability to transfer power between regions. In addition to the primary connections "across the border" it should include secondary lines that create technical limitations on the primary flow paths and any associated services such as network support and other ancillary services that may affect the capability to transfer power between regions;
- Imposing a requirement within the regulatory arrangements to institute an annual, nationally focussed consultation/planning cycle over and above the requirement for NEMMCO to produce the ANTS;
- Developing mechanisms that allow for the possibility of both "private" and "public" funding of projects that deliver mixed private and public benefits;
- Establishing a clear focus on long-term strategic developments, issues and programmes; and

- Only considering specific projects within the regulatory arrangements in the context of such long-term programmes.

2. A key element of the improved arrangements we envisage is an arrangement to produce a broad strategy for possible development scenarios for the national transmission network:

   - The scenarios would be informed by projections of options for future generation and demand growth and evolve in the light of actual developments;
   - Individual TNSPs would be required to use the scenarios as the starting point for assessment of individual projects and expenditures to demonstrate how each supported the broad national strategy;
   - Generators and consumers would draw on the scenarios to inform their assessments of the impact of their options for future investment and operations including for example the outlook for congestion;
   - The scenarios could be developed as an extension of the SOO/ANTS process on an annual basis and involve consultation with stakeholders; and
   - The scenarios should be used by the AER, in setting revenue caps for TNSPs in each regulatory control period.

   Existing misaligned incentives on TNSPs due to overlapping obligations under jurisdictional regulatory arrangements and national market objectives would need to be resolved to facilitate a national perspective

3. Service standards should be linked to the specific performance characteristics on which an investment is based (regardless of whether investments are based on the current self-administered test or another form of approval process under revised governance arrangements)

4. The right for a relevant body such as the AER or AEMC to identify, and require consideration of, inter-regional developments which appear to have been overlooked by the TNSPs involved should be retained (in effect, continuing the planner of last resort philosophy).

5. The Regulatory Test should be aligned with the decisions taken with respect to regulatory structure and philosophy at the national level such that:

   - If the Regulatory Test is to perform a *regulatory* function, the associated processes should be clear and result in explicit investment approval or rejection. In this case, administration of the Regulatory Test would sit naturally within the context of a national planning body that approves project commitment decisions. However, this is not the current regulatory structure, and it would sit awkwardly within the context of the existing incentive-based regulation regime;

- If the Regulatory Test is considered a planning process requirement (which is more what it represents in the present regulatory environment), it should be rewritten explicitly in that vein. The automatic roll-over of actual expenditures (adjusted for depreciation) from one regulatory period into the next should then be constrained by agreed thresholds related to the "results" of the consultative application of the "test". For example, if actual expenditures materially exceed those that were indicated as part of the "test", then rollover of the excess could be subject to further review. At a minimum, further consultation should be required should there arise a materially different level of expenditure from that which was the subject of the "test". It is important to note that such an arrangement is not intended to conflict with the concept of incentive regulation where a TNSP has an approved capital expenditure for a regulatory period. Instead the arrangement would act as a discipline on a TNSP's ability to unilaterally increase capital expenditure materially above the amount that has been subjected to the "test". The Regulatory Test process would then need to be enhanced so that it establishes appropriate targets and tolerances so that the requirement to revisit consultation does not of itself create inefficiencies.

- Over the longer-term, we also recommend consideration of development of a negotiated approach to transmission system developments. A number of significant changes, including acceptance of mixed public/private developments, the establishment of a national coordinator and/or negotiating agent, and significant changes to transmission cost recovery would be required to achieve such an outcome. Such a framework is suggested for consideration as a longer-term development, rather than for immediate implementation.

6. Additional changes that would complement our recommended changes to the Regulatory Test include:

- Developments to enhance competitive neutrality between transmission and non-transmission alternatives by increasing the ability of the latter to obtain long-term, low risk, financial support, where providing equivalent services; and

- Developments to provide more appropriate commercial signals to participants – signals that better reflect constraint impacts, including both "locational" and ancillary service impacts – most probably through some form of market based congestion management regime.

2. INTRODUCTION

CRA International Pty Ltd (CRA) has been engaged by the Department of Tourism, Industry and Resources on behalf of the Energy Reform Implementation Group (ERIG) to advise on a number of matters concerning transmission within the National Electricity Market (NEM). Firecone Ventures Pty Ltd (Firecone) has been commissioned to undertake a complementary review of governance arrangements.

2.1. APPROACH TO ASSESSMENT

In considering the questions posed in the terms of reference for this study:[2]

- We firstly review the existing arrangements by:
  - Outlining the incentive regime for transmission investors and owners so as to provide a mixed qualitative and quantitative assessment of the operation of the incentive regime; and
  - Examining the role and importance of the "Regulatory Test" that Transmission Network Service Providers (TNSPs) are obliged to follow before making significant investments.
- We then assess the potential for change to the overall structure of regulation applicable to transmission and to the details of particular elements of the existing regime. Where necessary to address the questions posed to us, we consider changes with respect to existing governance arrangements although these matters are being addressed in detail in the work by Firecone.

The ERIG has indicated that the direction of development of a national framework is expected to lead towards:

- *A structure in all regions across both gas and electricity that is efficient, supporting competition and open entry;*
- *A level playing field for operational and investment decision-making across regions and between technologies;*
- *Operational arrangements for the regulated transmission sector that support commercial trade across the national market;*
- *Operational arrangements that drive efficient market-oriented investment within and between regions;*

2 See Appendix A:

- *The efficient utilisation of the national network by appropriately motivated TNSPs and through an effective interface between the competitive market outcomes and regulated sector outcomes;*

- *Appropriate planning functions coordinating network development nationally, within and between regions, identifying efficient projects or project enhancements; and*

- *Appropriate and transparent information functions that provide participants with the information necessary to undertake investment decisions.*

We have used these characteristics as the basis for assessment of the arrangements and as a guide to how changes might be developed.

2.2. Current Arrangements

The NEM design allows multiple transmission and distribution network owners and operators. Subject to technical and relevant jurisdictional licensing requirements, any number of network operators can provide network services in the same area.

Appropriately registered TNSPs and Distribution Network Service Providers (DNSPs) are entitled to recover the costs associated with the provision of regulated services via tariffs imposed on parties connected to their network. In some instances, we refer to TNSPs and DNSPs, collectively, as NSPs. TNSPs also provide:

- Connection services to generators, transmission connected customers and DNSPs for their connections to the transmission network; and

- Negotiated services to parties seeking services that are not regulated, for example network capability over and above that required by relevant minimum performance standards.

Although multiple TNSPs may operate “side by side” within a geographic space, in practice a single TNSP provides substantially all of the transmission service in each state. In contrast, different DNSPs provide service in different geographic parts of each state. The major NSPs have evolved from the transmission and distribution arms of previous state government utilities.

Under the National Electricity Rules (NER), Market Network Service Providers (MNSPs) may also provide unregulated transmission services between pricing regions of the NEM. MNSPs are not subject to economic regulation and are not entitled to recover any revenue through tariffs on network use. MNSPs, however, are entitled to the "settlement residue" that accrues in the NEM settlement system arising from differences in prices between relevant market price regions and the flow on the MNSP network.[3] Incentives for investment and operation by MNSPs are derived from competitive market arrangements and thus are not the focus of this current work. Experience to date in the NEM is that network services are substantially provided by regulated entities. TNSPs are the focus of this report.

2.2.1. Overview of the Regulatory Regime

Economic regulation of the NEM transmission sector is based on incentive-based regulation principles. The TNSPs operate under a revenue cap with respect to those components of service that a TNSP provides that are subject to full regulation. We have accepted this basic structure as given for this work.

A revenue reset process is followed in which an allowed level of revenue is determined for each TNSP for the next regulatory period. Currently the regulatory period required to be a minimum of five years. The setting of the revenue cap is intended to allow recovery of capital incurred in developing existing assets, a return on capital invested in those assets and on expected new capital expenditures and operating costs in the forthcoming regulatory period.

TNSPs must subject any significant new investment project to an assessment under the "Regulatory Test". The TNSP's assessment is open to review by stakeholders, and in some circumstances prospectively by the Australian Energy Regulator (AER).[4] The role and detail of the Regulatory Test has evolved over time to the point where it is now principally a form of consultation with no formal approval decision. The primary purpose of the Regulatory Test in its current form is to give stakeholders the opportunity to challenge the veracity of an assessment by a TNSP of a particular project proposal. It is open to the AER to review how a TNSP applied the Regulatory Test during the previous period at each five-yearly regulatory reset processes but not to retrospectively accept or reject the results.

---

3 TNSPs receive an equivalent amount but are required to pass it through to network users in the form of reduced tariffs.

4 For proposals that are at an advanced stage at the time of five yearly regulatory reset submission to the AER

The regulatory regime has evolved considerably since the launch of the NEM in 1998. Initially, jurisdictional regulators held primary responsibility for transmission regulation in their respective jurisdictions. This responsibility was transferred to the Australian Competition and Consumer Commission (ACCC) and more recently to the AER. Important aspects of the ACCC/AER regime have also changed with the result that each of the reset decisions for different TNSPs has been conducted on a different basis.

A key change in the regime relates to the treatment of actual capital expenditures by a TNSP. Under the regime in place at the start of the NEM, TNSPs were subject to a full *ex post* optimisation review of their asset base. Capital expenditure deemed in hindsight to be inefficient could be written down; previously written down investments whose utilisation was subsequently required, could be written up. These adjustments were possible regardless of whether expenditure was regarded as prudently incurred at the time it was made. The initial provisions also required that a central body perform the Regulatory Test.

As a result of the continuing evolution of the regulatory regime the different TNSPs are operating under different combinations of *ex-post* and *ex-ante* arrangements.

Along the way, the Regulatory Test, which originally focussed solely on market benefit, gained a second "limb" corresponding to reliability. The "market benefit" limb requires that the proposal provide nett market benefit, which represents the summation of consumer and producer surpluses. Guidelines for the conduct of the test issued by the AER describe how this assessment is to be undertaken.

The second limb is known as the "reliability limb" and allows for proposals that are shown to be *necessary* in order to meet prescribed standards set in applicable regulatory instruments, including the NER and licences and codes issued by jurisdictional authorities. In order to satisfy the reliability limb the proposal must be shown to be minimum cost.

The evolution of the Regulatory Test has reduced the risk to the TNSP associated with an *ex post* write-down in value of an investment they have previously made and expected to recover through regulated charges. The most recent changes introduced by the AEMC reduce this risk yet further, such that any and all TNSP expenditures incurred as of the date of a revenue reset would be rolled into the opening asset base for the next regulatory period, subject to adjustment for depreciation as part of the incentive regime.

The overall regime therefore relies almost exclusively on the Regulatory Test process, which in turn depends heavily on the active participation by stakeholders, as the primary, if not essentially only, formal check against specific inefficient investments by TNSPs. As noted elsewhere and also highlighted by Firecone the test is not a test in the usual sense of the word, but a consultation process.

The Rules require that non-network alternatives such as generation and demand side options must be included in the Regulatory Test, giving corresponding stakeholders some leverage, or at least a basis for providing input.

TNSPs are able to set tariffs to recover the revenue, approved in a revenue reset process, from network users. During a regulatory control period a TNSP has an incentive to reduce its operating and capital costs so as to increase its profitability. The arrangements are a complex balance between incentive and certainty and between capital and operating costs. The effectiveness of the regime as a way to discourage inefficient capital expenditure depends on the net effect of the benefits to the TNSP of earning more profit during the regulatory period by curtailing expenditures and the ability to make an investment that will be reflected in the regulated asset base during the next and subsequent regulatory periods. These effects are complicated by the TNSP's perception of the risk associated with *not* making an investment, and thereby breaching performance standards.

The capital expenditure incentives thus reduce during a regulatory control period, and are reset at the start of each period. Detailed arrangements also provide for the carry forward into the subsequent regulatory period of some of the savings due to operating efficiencies. The associated arrangements are intended to ensure that there is an incentive not only for the TNSP to focus on within-period efficiencies, but also to pursue operational efficiencies that would not be economic were the potential recovery period truncated by regulatory "claw back".

2.3. TNSP Business Model Map

As part of our brief we have been asked to develop a high level business model of TNSPs. Due to the complexity of the arrangements and their evolving nature there is no single arrangement in place. In addition, not all of the relevant arrangements are amendable to quantification. Accordingly, we trace the relationships amongst the relevant arrangements and discuss their quantitative and qualitative significance.

The resulting "map" is shown in Figure 1, which shows:

- Two adjacent TNSPs, each subject to the NEL, NER and their local jurisdictional regulatory instruments (e.g. a licence). The instruments create a combination of obligations and incentives on the TNSP shown on the left of the diagram;
- Within their respective revenue caps, each TNSP determines its operations and develops proposals for investment that are subject to the Regulatory Test (investments that are below the threshold for the Regulatory Test are not shown);
- Investment and operating practices can affect generators and customers in the energy market and the DNSPs, as shown by interactions to the right of the map. Note that the effect on energy market participants is not confined to the market region in which the TNSP operates, and hence the diagram shows connections to a common energy market, whereas connections to DNSPs are restricted to the same region in which the TNSP operates; and

- Interconnections between regions of the market involve the joint actions of corresponding TNSPs. The associated interactions create incentives for the different parties to involve themselves in the review of Regulatory Tests performed by the TNSPs, although these incentives may well be muted by the fact that there is no requirement on the TNSP to even acknowledge responses from other stakeholders, or even to construct the project that was the subject of the test.

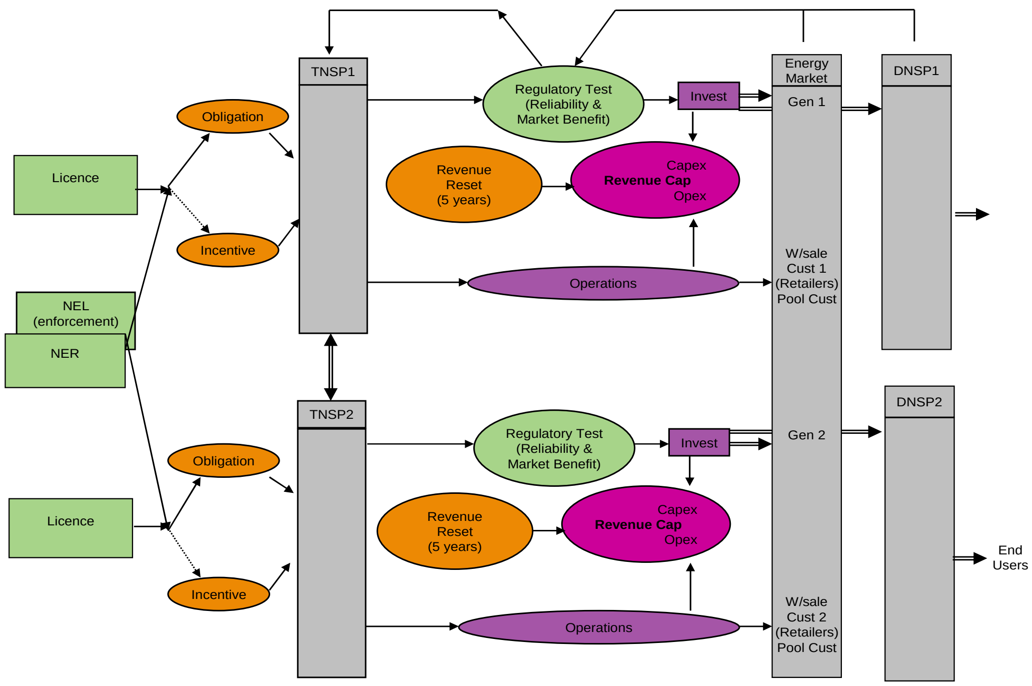

Figure 1: High Level Incentive Relationships

The industry and regulatory structures result in three forms of incentives on TNSPs:

- Obligations under jurisdiction licences – these can be quite strong drivers for the TNSPs and they technically involve the ultimate sanction of loss of licence and hence significant risk of financial loss;

- Financial incentives within the regulatory regime under the NER; and

- Reputational impacts – these can provide a strong incentive under certain circumstances. Apart from seeking to avoid public and potentially political embarrassment associated with network failure, a TNSP is presumed to have at least some incentive to conduct itself sufficiently efficiently as to avoid becoming the target of regulatory reform or persistent stakeholder disputes, claims or submissions during regulatory reset hearings.

TNSPs claim that there is a reputational incentive to comply with the spirit of the regulatory regime and minimise the risk that the regulator, to the extent that it is able, will be more aggressive in a subsequent reset processes

Compliance with the provisions to consult and disclose relevant information under the Provisions of the Regulatory Test is crucial to maintaining good standing in this regard. In addition the provisions of the NER requiring TNSPs to comply with the Regulatory Test and to publish information are potentially powerful measures to force such compliance within a regulatory period. However compliance arrangements have not, to our knowledge, been tested in this regard. Section 3 provides further detail about the arrangements and the current state status of the regulatory test, and Section 4 provides an overall assessment including quantification by way of examples. Section 5 presents options to improve the overall framework and section 6 provides detailed options for improvements to the Regulatory Test

3. THE REGULATORY TEST

The intended role of the Regulatory Test as a part of the checks and balances against inefficient capital expenditure by TNSPs has become less and less clear over time.

3.1. ROLE OF THE REGULATORY TEST

The MCE's first proposed draft principle suggested that the test:

> *".. must have as its purpose the <u>identification</u> of new network investment or non-network alternatives that …. (best achieve economic and reliability objectives)*[5] *<u>(emphasis added)</u>*

The AEMC, considering the MCE's draft principle, concluded that:

> *"… the role of the Test is to <u>promote</u> efficient investment, regardless of whether that investment is regulated or un-regulated, or is in network assets or non-network alternatives. In doing this, it acts as a <u>filter</u> for investment proposals, by <u>revealing</u> information regarding likely investment alternatives, <u>ensuring</u> that inefficient proposals are rejected and efficient proposals are <u>identified</u> and have incentives to proceed"*[6] *<u>(emphasis added)</u>*

5 Ibid

6 Ibid

The AEMC's statement could form a description of either a *test or* a consultation *process*. If it is conceived as a test, the natural next step is to ask what it means to pass or fail the test, and what consequences flow from that? Indeed, if the Regulatory Test is seen as a *test,* then should there not be regulatory consequences associated with passing or failing? But is this the case?

- The drafting of the Regulatory Test seems designed to achieve *approval* of specific developments. In the initial stages of the NEM this was its role. In this role, passing the test might be taken to imply approval of the associated investment expenditures, and thus approval of recovery of costs incurred. In practice, however, the linkage between test outcomes and the five-yearly "reset" is now only indirect.

- As a *test* it would seem to suggest that an independent regulator has the power to decide whether projects will proceed (based on whether the test is passed or not) and/or whether their costs will be recovered. However, under current arrangements, the Regulatory Test is self-applied by TNSPs, and no party has the direct role to force TNSPs to comply with the outcome. Indeed, it is possible that *actual* project designs, and associated costs, could differ materially from what was decided when the test was applied. Enforcement and sanctions needed to achieve robust administration of the test include the NER enforcement regime, the dispute process within the NER, and on an implied threat with respect to how the AER might choose to deal with the particular TNSP at the next regulatory reset process. None of these are direct or simple to apply.

Currently, the test is able to be applied at the initiation of TNSPs on an essentially case by case basis for particular projects, which may involve expenditures from $10 million upwards. Consultation on expenditure below $10 million is not required and the test outcomes have no formal linkage to revenue recovery.

In our view a requirement to subject projects to some form of test has the potential to filter out (really) bad projects.[7] However, it is more difficult to develop a test that assures a systematic, transparent or reliable identification of "good projects". Under the current form of test, the incentive to develop appropriate projects, or solicit valuable input, or administer an effective consultation, all derive from the revenue cap and reset provisions and a sense of what adverse consequences could befall a TNSP that does not apply the test rigorously or effectively.

7 Furthermore, while the test requires that a wide variety of alternatives be considered when evaluating transmission projects, the application of the test appears intended or application only to decisions involving "transmission assets", whitch are the only assets to which Rule 5.6.6 refers.

3.2. EFFECTIVENESS OF THE REGULATORY TEST

The practical effectiveness of the Regulatory Test process has been debated extensively over the past decade or so, both in Australia and elsewhere. We note that there is no universal solution, nor even a perfect solution for the circumstances of any particular market. As a result the current regime in the NEM, like any other, is the product of the need to find an acceptable compromise amongst conflicting priorities.

In informal discussions, several TNSPs have indicated that the test remains a key part of the regulatory oversight of their behaviour and that it has served as an effective brake on their activities. Clearly, in its current form, the test is the primary process by which TNSPs present their proposals for augmentation to stakeholders. The role of the AER in reviewing the results has varied as the arrangements have evolved. Under the new arrangements, the AER is likely to review results of regulatory tests or at least the TNSP's preliminary analysis for future expenditure, as part of the regulatory reset process but has no more extensive role.

For each individual project with an expected cost exceeding $10 million, a TNSP must administer the Regulatory Test. Depending on the circumstances, the review and vetting of the Regulatory Test is by a combination of the AER (to the extent this is practicable during a revenue reset) and by those stakeholders who challenge the veracity of the analysis or assessment of alternatives. Commentary or objections, in the form of submissions to the TNSP, can be made by generators, customers, other TNSPs and, potentially, DNSPs. Interestingly, DNSPs have incentives to challenge a proposal from TNSPs as in some cases a TNSP investment can preclude potential DNSP investment, thus depriving a DNSP of an opportunity to invest. Where there is common ownership of transmission and distribution, assessment analysis of options for investment will be internalised, and the interested stakeholders limited to generators, customers and potentially the AER. Where there is separate ownership, the field of interested parties includes the DNSP in those circumstances where an alternative investment could be made in the distribution network, and also where their quality of service is affected.

The TNSP need not necessarily heed these submissions, however. Parties dissatisfied with the TNSPs responses must then raise a formal dispute. While large generators or retailers will be in a position to match the resources of a TNSP to defend a dispute others will be at a disadvantage. For example, there is nothing in the Regulatory Test itself to prevent a TNSP from determining that implementation of a project needs to be changed after the Regulatory Test has been completed, or determining that the capital expenditure should be higher than the level that was presented in the context of the Regulatory Test. It is therefore necessary to look beyond the application of the Regulatory Test, and to consider other aspects of the regulatory regime when determining the likely effect on TNSP behaviour.

The effectiveness of the Regulatory Test process is very much determined by how well it serves as a focal point for a consultation process, and how well that consultation process serves to constrain or influence TNSP behaviour. The quality of information presented by the TNSP, the skill and resources of stakeholders to absorb, analyse and provide substantive responses, whether a TNSP provides a genuine response to submissions, and what sanctions and enforcement powers exist to either directly or indirectly shape the behaviours of all parties are crucial elements of a good consultation process.

In this regard we note that it is natural for there to be a focus on the performance of the TNSP in how it undertakes the test. It is equally, if not more, important that stakeholders respond to the TNSP's proposal with detailed and rigorous analysis. Such participation is especially important where the comments are criticisms that suggest the TNSP is wrong about matters of fact or analysis, and should therefore have reached a different conclusion. It is, of course, a situation in which stakeholders are best able to make substantive contributions if a TNSP has provided comprehensive analysis and information. The incentives on stakeholders to participate in the test process in this way, however, depend on whether they perceive they will be able to influence test outcomes, and on how material the outcome is to those stakeholders. The quality and timeliness of information provided by TNSPs is thus crucial to the effectiveness of the regime.

3.2.1. Role of dispute regime within the NER

The final step for an aggrieved participant is the dispute process within the NER and this has the potential to play a significant role in creating incentives for all parties to comply with the NER to the fullest extent. To our knowledge these provisions have not been used to any degree. Explicitly linking the ANTS process with other provisions related to planning under the NER, as suggested elsewhere in this report, also would allow greater use of the dispute process to test the rigour of the material presented within a regulatory test for a particular project, or as suggested below, with respect to long term development programmes. This would strengthen the effectiveness of the test, or consultation process.

4. ASSESSMENT

In this section we present an assessment of the performance of the regulatory regime as it affects the incentives operating on TNSPs.

4.1. CRITERIA

The ERIG secretariat has suggested the following list of characteristics that might be used to describe a fully national transmission grid:

- *The structure in all regions across both gas and electricity is efficient, supporting competition and open entry;*

- *There is a level playing field for operational and investment decision making across regions and between technologies;*
- *Operational arrangements for the regulated transmission sector support commercial trade across the national market;*
- *Operational arrangements drive efficient market oriented investment within and between regions;*
- *The national network is utilised to its fullest by appropriately motivated TNSPs and through an effective interface between the competitive market outcomes and regulated sector outcomes;*
- *Appropriate planning functions coordinate network development nationally, within and between regions, identifying efficient projects or project enhancements; and*
- *Appropriate and transparent information functions provide participants with the information necessary to undertake investment decisions.*

We have grouped these criteria for the purposes of analysis and summarised our findings in Table 1. The following section reviews the quantitative evidence available.

Table 1 Assessment of the Current Regime

CRITERION	ASSESSMENT
National v Jurisdictional Focus	The obligations and incentives on TNSPs have a strong regional bias. Regulation is by individual TNSP which in general means for each jurisdiction in turn. Inter-regional investments rely exclusively on market benefits compared to the clear physical obligations for reliability set within jurisdictional instruments. Although it is difficult to quantify what might have been, the ANTS process is now reporting on prospects for inter-regional investment projects and broadly assesses possible market benefit. What the process does not do is consider broader programmes for development of networks or require presentation of broad strategies for development across adjoining TNSPs as background to consideration of individual developments.
Compatibility with Market based investment and trading	Performance Incentives consider some physical measures broadly related to market operation. Project alternatives which maximise market benefits, for example alternatives which provide greater firmness in the Settlement Residue Auction (SRA) could be presented but TNSP has no inherent reason to present such options, and in fact a perverse incentive not to, as less congestion means less revenue to offset TUOS charges and hence apparent higher TNSP charges.
Investment Planning	Investment planning is focussed on individual projects. Coordination between TNSPs is required to some degree in order to produce ANTS and any interconnector project Regulatory Test.
Operational Incentives	The regulatory regime includes incentives for TNSPs to make opex savings. Jurisdictional obligations constrain the effect such savings might have on jurisdictional performance. While considerable effort is being directed by AER, and in AEMC reviews, to developing operational incentives that align with market objectives, currently these are entirely informational and do not have a financial effect. TNSPs note a reputational incentive to avoid operational activities that prejudice market operation. Overall, however, current operational incentives are biased against arrangements that facilitate market operations. For example, although it would "not be inconsistent" with meeting a market benefit test a non-network ancillary service agreement that enhanced interconnector capability under certain conditions would be unlikely to be presented – there is simply no incentive for a TNSP to develop such a proposal.
Neutrality	There is a risk that economic assessment will favour regulated network investments because the discount rate for a network investment assured of a regulated return for the long-term will be lower than for a non-network alternative, unless the alternative is able to be contracted or otherwise remunerated with the same security.
Transparency and Information	The Regulatory Test and the ANTS are increasing the level of information that is available to stakeholders about network plans. Our assessment is that there is a gap in the design in that broader strategic plans should be a key part of the process and this would reduce the significance of Regulatory Test reviews on a project by project basis.

4.2. Quantifying Effects

4.2.1. Background

Quantifying the effects of potential deficiencies and opportunities for improvement in arrangements potentially can contribute to a more robust assessment of the costs and benefits of possible changes to those arrangements. The effects of deficiencies in the regulatory arrangements and market incentives are, however, complex and considerable care needs to be taken to avoid double-counting (or failing to capture the full spectrum of) possible effects.

Considerable care needs to be taken in interpreting data about network performance. A common measure is network congestion. Congestion occurs when flow in part of a network reaches its safe operating limit and in a normal alternating current (a.c) power system this requires that the system operator change the pattern of dispatch of generators to avoid unsafe loading levels. Such changes are needed because the distribution of power in different parts of an a.c. network is determined by the characteristics of the network and cannot be controlled, except by the use of special control devices which are only cost effective in limited circumstances. (Direct current d.c. networks as is used in Directlink, Murraylink and Basslink) generally do allow control of flow along different links of a network.) The overall limit on flows commonly reflect the first part of a network to reach its limit, and this implies that relatively minor elements of a network can effectively limit the use of primary elements. This is the situation in a number of cases in the NEM where limits on major interconnectors are determined by secondary limits that are reflected in the NEM as “binding constraints” on the operation of the interconnectors. In addition flows can be limited by “system transfer” limits, for example a stability limit, that is not related to the capacity of any particular element but to the nett effect of all elements in a part of the network and sets the safe level of transfer across large sections of the power system. Upgrading one element may make a dramatic impact on individual limits but have only limited effect on system limits.

Typically it is not economically efficient to invest so as to avoid all congestion, and it can be difficult to distinguish between economically efficient levels of congestion and inefficient congestion. Congestion can also result in significant impacts on price (through wealth transfers) resulting from changes in price due to market behaviour without any change in the underlying industry costs. This can deliver increasing financial benefit to one sector at the expense of decreasing it to the other: for example where price rises generators are better off but customers worse. Wealth transfers, however, are not normally counted in an economic benefit / cost assessment but can be the primary motivation for stakeholder support for, or opposition to, specific investment proposals and making it all the more difficult, to distinguish accurately between economic costs and benefits and wealth transfer impacts. Put another way, there is a risk of an economically inefficient investment being made to counteract the effect of another inefficiency –say due to limited competition in the generation sector resulting in raised prices and prompting the question of whether transmission should be the instrument to manage the underlying cause of price difference as at least in the short term energy prices are reduced.

In addition, finding that congestion has occurred in practice that, with the benefit of hindsight, could have been avoided does not necessarily mean that it was avoidable given the knowledge available before the event. On the other hand the absence of congestion may also be indicative of an inefficient outcome if it results from over-investment or less efficient dispatch of existing capacity.

To date, overall congestion in the NEM has been relatively low. Statistics published by the AER and presented in Table 2, show that while there have been some notable exceptions, the majority of congestion occurs across existing regional boundaries, where it is priced in the energy market. However, those statistics also show that some of those restrictions are due to secondary limitations of the nature described.

Further a significant percentage of congestion that has occurred is attributable to conditions where an element of the network was out of service for maintenance or to allow maintenance of plant or equipment. Even these instances, however, were relatively few in number. In general, the impact of outage-related congestion can only be reduced by duplicating network elements (or investing in additional, but mostly unused generation capacity on one or both sides of a potential outage candidate), and it is unlikely that such investments would be economic unless the outage probability and impact were very high.

However, the financial impact of outages can be quite significant for specific participants. Elsewhere we have previously suggested that the selective application of congestion management arrangements could be helpful in addressing such circumstances. We note that the AEMC is currently conducting a review on congestion management within the NEM and is considering these issues.

Table 2**Error! Reference source not found.** summarises the percentage of time congestion within and between market regions forced a different dispatch of generation for more than one percent of the year as reported by the AER. One percent has been chosen as an arbitrary small number of hours for that table.

The AER also reports three cost indicators and data for congestion related to outage conditions. We have not included either 1) the dollar value of the outages as we do not have information about other sources of congestion that might affect the same transmission elements if the particular source of the observed congestion were removed and 2) statistics of congestion under outage conditions, as it is unlikely that it would be economic to duplicate transmission to remove congestion under outage conditions. Congestion during outage conditions is also very variable over time and is very amenable to management through operational performance incentives and this is an area currently being pursued by the AER under the current regime and is also within the ambit of the AER’s review of congestions management.

Table 2 Key Congestion Statistics – All plant in service: Elements Affected Greater than 1 percent of year

	2003/04		2004/05	
Transmission Line	**Hours of Congestion**	**Percentage of Year**	**Hours of Congestion**	**Percentage of Year**
Queensland – NSW	173 (stability)	**2.0**	175	2.0
	113 (network)	1.2		
Victoria – SA *	1354	15.5	975	11.1
Victoria nett to Snowy/SA	162	1.9	93	1.1
Central Queensland	(29)	(<1%)	234	2.7
Victoria: Latrobe Valley restriction	163	1.9	101	1.2

* Limits on transfers between Victoria and South Australia were dominated by a temporary technical limit imposed to manage risk of coincident loss of two SA generating units that had previously led to breaking of interconnection and was not directly related to network design. This limitation was lifted in 2005.

In order to assess the operation of the investment regime it is therefore necessary to examine individual cases. It is impossible, however, to present a review of individual cases without identifying explicitly or by inference, the parties involved. We have limited our review to publicly available information. The purpose here is not to engage in debate or judge the merits of the specific instances, but to consider whether a more broadly based case for concern about the design of the regime exists. We have done this by summarising a limited number of cases where decisions or applications by a TNSP have been challenged by stakeholders or rejected by regulators. In some cases the design of the regime has now been amended and similar challenges are no longer possible but the examples highlight the magnitude of the decisions at stake and the reason for ensuring decision and review processes are the best available.

Finally, we note that although an increasing amount of information is published there are still claims from stakeholders that it is insufficient to allow robust analysis and response under the regulatory test.

With these points in mind, in the remainder of this section we examine the three main areas of potential inefficiency and consider the evidence that is available to quantify impacts as far as is practical and defensible. In considering this evidence, we find little substantive quantitative evidence of serious problem but a series of questions that it is not practicable to assess without detailed study and information that in many cases only the TNSP will possess.

4.2.2. Inefficient Investment Proposals

The first source of possible inefficiency we consider relates to the possibility of inefficient investments which have occurred in practice, or were proposed, but were not optimal for one reason or another. For example, where a proposed project was not actually required, or could have been deferred.

We are aware of anecdotal claims of inefficient investment, but it is difficult to find analysis for more than a small number of such claims. The best source to determine whether inefficient projects have been planned is found in the ebb and flow of debate in regulatory reset submissions. The following are presented as examples on the public record, in order to illustrate the case for improvement. As we have noted previously we have not set out to reconcile the merits of any of the claims or positions taken by any of the parties. These examples simply highlight a range of views and perceptions and the magnitude of what is at stake:

- In its 2005 decision in relation to Transgrid, the ACCC disallowed $99M of proposed expenditure on network assets out of a total of $1.2B capex from Transgrid's application.[8] While the ACCC accepted arguments that the proposed investments were not required, Transgrid and a number of generators serviced by the proposed works each submitted that they were needed;

- In its 2002 decision relating to Electranet the ACCC reduced the capex allowance from $374M to $358M after making a number of adjustments. It also re-admitted assets that had been removed from the Electranet asset base previously due to low utilisation (it had previously removed $13M from the asset base of approximately $800M). [9]

- More recently, Snowy Hydro criticised Transgrid's application of the regulatory test in relation to its current plans to upgrade the 500kV network around Sydney.[10] A series of upgrades costing hundreds of millions of dollars have been foreshadowed over a period of years. The overall development will affect reliability of supply to the wider Sydney area as well as inter-regional transfer capabilities into Snowy and Queensland and the attractiveness of generation investment at a range of locations within NSW.

---

8 ACCC 2005, Final Decision, NSW and ACT Transmission Revenue Cap, Transgrid 2004-05 to 2008-09. A total of $237M was disallowed including $99M for network augmentation, $38M from business support and $92M associated with contingent projects and other minor adjustments.

9 ACCC 2002, Decision. South Australian Transmission Revenue Cap 2003 to 2007/08

10 Snowy Hydro Trading 3 July 2006. Submission to Transgrid (available at www.transgrid.com.au)

> Snowy Hydro claimed that lower cost alternatives to the specific project proposed by Transgrid exist, and that some parts of the proposed project would not realise their claimed benefits because of imminent secondary (network) limitations. On the information provided, Snowy Hydro noted that it was unable, however, to quantify the magnitude of the effect, and sought additional information. In response, Transgrid advised that it intended to make some operational changes to the points of connection of certain generators, thus avoiding one of the problems raised by Snowy Hydro. Snowy Hydro was also concerned that the sequencing of the proposed augmentation would have significant detrimental effects on it, in ways that did not appear to have been examined in the material produced by Transgrid. In its final decision, Transgrid notes it has included additional material to address each of the points made.[11] In the context of this report we are not in a position to reconcile the claims and responses, but note that, given the long-term strategic impact of the augmentations in the Sydney area, this example provides a good example of the difficulty of project by project assessment through consultation and hence the significance of broader strategic plans in the assessment of individual projects.

As, *ex post* reviews of investment decisions are no longer to be conducted, scrutiny of planned expenditures in each regulatory reset undertaken by the AER will become virtually the only mechanism with which the AER can manage the risk of excess or inappropriate investment. As noted, scrutiny by stakeholders under the regulatory test (notwithstanding it now operates as a consultation process) will also be more important, again highlighting the need for a high level of transparency designed to assist stakeholders review proposals.

It is also possible that the low levels of actual congestion that have been observed may be indicative of over-investment allowing the majority of flows to occur unimpeded even though the network to allow this may not have been justified. While this is a possibility we note that there has been significant intra-regional investment and inter-connector upgrades in recent years and the low congestion within regions would appear to have been driven by the reliability criteria set by jurisdictional authorities.

While historical investments by utilities were biased towards jurisdictional regional requirements this was also influenced by the distribution of generation and load centres which in general simply were not close to state borders. Interconnections therefore involved long lines between the major load and generation centres and were not seen as cost effective. The principal exception is the Snowy Mountains scheme and its connections to the north and the south form the interconnection between Victoria and NSW.

11 Transgrid 2006, Final Report Development of Supply to the Sydney-Newcastle-Wollongong Area (October 2006)

Future resource limitations in South Australia and Tasmania and relatively high load growth south of Brisbane are creating the conditions where it might be expected that there will be a stronger case for interconnection to meet customer load from another region in the future. A key question then is will the regulatory regime aid or hinder the development of efficient network expansion to facilitate the most efficient generation pattern in the future?

The very limited amount of firm data that is available does not provide quantitative evidence one way or the other about the adequacy of investment incentives. This in itself is significant as the parties that are served by the investments and also those that pay the costs are unable to resolve differences and uncertainties and thus credibility of the regime is prejudiced.

4.2.3. Failure to Invest

A second source of inefficiency is a failure to invest.

Asset owners seek a return on investments and, subject to the regulator allowing a sufficient rate of return, making new investments is the key means asset owners have to grow their businesses. Furthermore, at least some investment must be made to avoid catastrophic network failure.

In principle, asset owners should have a sufficient incentive to invest in those projects that are necessary to at least maintain agreed reliability standards at a cost that is less than other available alternatives. But, more generally, the overall regime should facilitate discovery of, and investment in, those transmission-related projects that are, in some sense, optimal. Merely determining whether a proposed investment is “prudent” stops short of this mark.

In Section 6.2.1 we note that the inability to recognise combinations of market and reliability benefits from a single project (investment) is not appropriate, and must in the general case lead to situations where less optimal projects are developed than would be the case if the situation had been considered holistically

The data presented in section 4.2.1 shows that congestion in the NEM has been relatively low and the discussion notes that it is unlikely that it will be economic to “build-out” all possible congestion-related limitations, and therefore some congestion will invariably arise even when investment is optimal. Inspection of the data about congestion provides an indication of the potential materiality of a failure to invest but only due to the most restrictive limit and may disguise the effect of other only slightly less stringent limits. A key indicator of the limited effect is the relatively low number of hours constraints of any level have occurred other than during outage conditions. It is also important to note that at the low levels observed it is likely that the results will be volatile from year to year and the value ascribed to them also volatile. The AER statistics also provide a measure of the effect of removing all constraints. Values of $36M and $45M in 2003/04 and 2004/05 were found, however, these measures are imperfect as they assume no change in competitive behaviours and cannot assess what changes in investment pattern of generation or demand might have followed. Again the key conclusion that can safely be drawn is that congestion is relatively low in the NEM.

Nevertheless, when congestion occurs between price regions in the NEM differences in the prices in the affected regions occur and this reduces the attractiveness of interregional trading. In addition the risk that parties arranging contracts across an interconnector face from the rare but high impact of an unplanned interconnector can be very high and as noted congestion does occur during outages of parts of the network that although the timing of such outages can be controlled to some degree outages are required from time to time. To allow market participants to mitigate the resultant risk the rules of the NEM include a Settlement Residue Auction (SRA) mechanism whereby trading entities can acquire insurance or a hedge against the price differences. However the SRA mechanism is “non-firm” as it varies with the actual limit on flows. As a result the level of insurance can fall to zero if all transmission lines between to regions are out of service. This can be a major problem as this is the time when price differences are likely to be greatest. Hence uncertainty about the level of congestion or “firmness” of the interconnector reduces the value of the SRAs as a hedging instrument and thus the commercial viability of trading between regions. This matter might be addressed within the current arrangements for assessing proposals by specifically including alternative proposals that affect the level of “firmness”. This would be a relatively simple refinement of the existing arrangements

The interconnector between Queensland and NSW has attracted considerable attention. Until commissioning of Basslink it formed the only *new* interconnection in the NEM, that is a connection to a new region that was not a continuation or upgrade of a connection made the state utilities prior to the NEM. It was also initially in “competition” with Directlink an MNSP line that also operated between Queensland and NSW until the MNSP transferred to regulated status. The 2005 ANTS noted that there was a marginal case for upgrade but the 2006 ANTS shows that it is now not likely to be cost effective based on the market benefits. At the same time both Powerlink and Transgrid have projects to reinforce supply to both sides of the border to meet reliability criteria. Our reading of the planning reports is that, consistent with the current arrangements and no consideration has been given to combining the assessed benefits of interconnector upgrade and regional reinforcement. These observations are not intended to suggest that the assessments in the ANTS are wrong, but intended only to show, using a practical example, how the assessment might differ under different regulatory arrangements, with potentially significant reductions in congestion.

4.2.4. Inefficient Investment Patterns

In the longer term, failure to invest, or inappropriate investment, may also lead to more significant detrimental effects if a less efficient configuration of generation investment emerges as a result. In this situation, there may be little congestion once the generation/ transmission configuration is in operation. However the whole configuration may be sub-optimal, and would not have occurred if potential network limits had not threatened to restrict operation of a more efficient pattern of investment. This second type of effect therefore cannot be detected from analysis of congestion records, but may be more significant in the long run. The process for coordinating generation and transmission development planning is crucial in avoiding the development of inefficient investment configurations in this way. But so is the process of coordinating intra-regional and inter-regional transmission investment.

Given the regulatory regime of the NEM, it seems reasonable to conclude that incentives for intra-regional investment are likely to be stronger than for inter-regional investment, and it might be thought that this would be evidenced by significant inter-regional congestion, coupled with limited intra-regional congestion. But this is not necessarily the case. If generators perceive a likelihood that the transmission system will be developed so as to favour intra-regional over inter-regional trading they will focus their investment and trading activity accordingly, developing projects which are sited to take advantage of the anticipated pattern of transmission system development, and match intra-regional load growth. Conversely, this may be seen to imply a relatively lower requirement for inter-regional transmission capacity. The perception of bias may become a self-fulfilling, and self-reinforcing, prophecy. There would however be any evidence in the form of congestion patterns.

On the other hand, it is important to note that network congestion is only one factor in determining the location of new generation plants, and it would be dangerous to conclude that any particular investment might have been different solely on the basis of considerations of congestion on the network. Other factors include the location of fuel and cooling water and proximity to labour. In particular, if the economic advantage of inter-regional generation development is strong enough, it will surely force the development of inter-regional transmission capacity in the long run, and/or create inter-regional congestion in the short run.[12]

Key conclusions that can be drawn are that:

- Efficient planning for generation and networks requires that it be integrated and that at present there is an artificial separation into regulatory planning and competitive regimes. The challenge for market authorities is to craft arrangements in both areas that are compatible and mutually supportive;
- It is important to balance:
    - Incentives for intra-regional vs inter-regional investment;
    - Incentives for developments by TNSPs operating in different regions of the market; and
    - Arrangements for generation and networks (including for embedded generation within distribution networks.

12 The first being an investment issue, driven by LRMC, and the second an operational issue, driven by SRMC.

5. OPTIONS TO IMPROVE THE OVERALL FRAMEWORK

5.1.1. Overview

In this section we present a number of options to improve the overall framework in which networks invest and operate to protect against the forms of inefficiencies we have identified in the previous sections. In particular we consider ways to link planning and operating arrangements between the energy market arrangements under the NER and the regulatory arrangements and consequently the incentives on TNSPs.

If taken literally, the current process:

- Requires assessment of stand-alone “projects” rather than integrated development programmes;
- Calls for a case by case analysis of each proposal; and
- Does not link the provisions in the NER relating to the ANTS with the regulatory process and hence revenue of TNSPs.

We are concerned that this orientation fails to capture the integrated nature of transmission planning, or allow proper consideration of its long-term strategic implications. Nor will it necessarily provide adequate warning of, or time to consider, projects with far reaching consequences. Indeed it may even encourage (or at least is not seen to discourage) TNSPs to surprise the industry on an “almost too late” basis, so that projects really have to be approved rapidly, to avoid imminent crises.

Wide benefits are likely to be available from a nationally coordinated annual planning/ consultation cycle that provides forward notice of likely developments, allows iterative consideration of major options, and provides greater certainty to all concerned. The Annual Planning Reports of the TNSPs already does this to some extent, but within the sphere of operation of each TNSP. In this section we develop three elements that could be incorporated to realise improvements:

- Re-focussing the Regulatory Test and associated processes, to deal firstly with strategic “programme” issues, rather than individual projects;
- Moving from a process of case by case assessment of particular projects to develop a robust and convergent annual planning cycle process;
- Developing at least some elements of a nationally coordinated planning process; and
- Linking service standards to the capacity that was used for the cost-benefit analysis that justified the investment.

Each of these is discussed below.

5.1.2. Re-focussing on Strategic “Programme” Issues

Previous sections have demonstrated that the current Regulatory Test fails to capture essential elements of the transmission system development planning question. A more sophisticated approach is required therefore to deal with assessment of major integrated developments.

The Regulatory Test distinguishes between “large” and “small” developments, however, it is inherently focussed on specific “projects” with specified development dates. And, while there is an understanding that the level of detailed analysis devoted to these projects should be in some sense commensurate with their significance, the underlying assumption seems to be that essentially the same project oriented approach should be taken with respect to developments which could range anywhere between a relatively small lower bound of $10m in cost, up to an unspecified level.[13]

But the reality is that the most important developments are often large and complex, containing many elements and may well be classified as projects in their own right, but which would make no sense if assessed on a stand-alone basis. Such developments are also likely to take many years to plan and complete and largely constrain the way many smaller “projects” should proceed, but the focus of the current arrangements is on the individual consequential projects. In addition the components which are actually built may well differ significantly from those which might have been envisaged when the overall development was first considered, and the timing almost certainly will. Thus we believe it is not appropriate to think in terms of assessing individual projects in such a development on a stand-alone basis. We consider that the emphasis should be shifted so that the primary focus is on development “programmes”, rather than projects.

There are two parts of the overall current arrangements that go part way towards a programme focus:

- The first is seen in the most recent developments with respect to what are known as “contingent projects” and is consistent with the programme focus we propose, but is still primarily project oriented. The contingent project concept recognises that some projects should only proceed if certain conditions emerge: for example the upgrade of services to an area may only be required if a major new customer load that has been foreshadowed but not confirmed actually proceeds. A programme focus would place considerably more emphasis on development of an overall integrated plan, rather than just a list of contingent projects as is the case now; and

13 In passing, we note that an alternative way of conducting the analysis would be to determine those optimal dates for each scenario, and then settle on a date which seems best, given that range of dates and the cost/benefit sensitivities of delay derived from the analysis. This is not the same as choosing a single date which is optimal ”*in a majority of reasonable scenarios”,* as per Clause 5 of the current Regulatory Test, and it allows for consideration of factors which are (by design) likely to favour earlier, rather than later development, so that minimum requirements are at least met under most likely scenarios.

- The second is the current NER requirement that NEMMCO produce the ANTS each year. The requirements for the ANTS include many of the features required to support a national planning programme. However, the ANTS is not recognised in the formal regulatory requirements. While the regulatory arrangements currently require assessment of projects under a range of scenarios, but not necessarily the scenarios of the ANTS, or more importantly not necessarily with a national focus.

Consequently while a TNSP may, and indeed is likely to, take into account the results of the latest ANTS, it is discretionary, and at the very least allows a perception that a TNSP may selectively examine projects within the ANTS. Similarly the focus of the regulatory reset process is the individual TNSP. The reset process does not link the role of the particular TNSP with the national objectives implicit in the ANTS.

Therefore, we recommend a shift in focus towards a programme development strategy. Implementation of a programme focus will require a more sophisticated approach to scenario design than appears in the current Regulatory Test. We recognise that a long-term strategic focus would involve greater emphasis on up-front planning. We envisage a graded application process to direct extra effort only to those developments that merit it. This principle is already recognised, at least in part, in the NER through the different requirements applicable to large versus small developments.[14] We see this as a move to a two-tier approach involving exposure and consultation about long-term development strategies and options in the first tier and consideration of specific projects within what would be thoroughly assessed and debated first tier strategies in the second tier. Within such a regime it would be possible for expenditure to be accepted (be it approved or consulted on) as necessary to ensure the ongoing viability of a particular development strategy and thus warranting and allowing recovery of associated costs.[15]

In particular, we note that under the regime some investment commitments may not involve construction of any physical asset at all, but the investigation and establishment of a transmission route by purchase of easements. Such expenditures would be far more readily understood and assessed by stakeholders in the context of a broader development strategy. A significant generalisation of the concept of what constitutes a “transmission investment” would need to be incorporated in the Regulatory Test to allow such changes.

---

14 This type of analysis also allows explicit analysis of the relative costs and benefits of delaying investment, versus making early commitments which may turn out to have been unnecessary consideration although the Regulatory Test process does not currently call for such analysis, we suggest that it should be modified so as to allow, if not require it. Consideration of such issues may imply an apparent bias toward pre-emptive transmission developments but, given the institutional arrangements, such a bias may have to be accepted as a “necessary evil”.

15 The New Zealand Electricity Commission has addressed this issue extensively in its adaptation of the Australian Regulatory Test. Although the resultant document is arguably open to alternative interpretations, and its first application has thrown up some issues in that regard, in practice the Commission has undertaken extensive analysis of the type discussed, and seems to be moving toward a de facto acceptance of a two tier approach.

5.1.3. A Robust and Convergent Process

Procedurally, a two-tier approach suggests a very different process from the current regime under which individual applications are dealt with on an essentially as needed, ad hoc basis. Despite the laudable intent of cl 5.6.6 of the NER in terms of laying down a strict timetable for consideration of the application and the registration of disputes, if the proposal is large and complex, and perhaps quite different from prior expectations, it is not necessarily bad if it takes more time for the proposal to be considered rigorously. This observation is particularly relevant given the range of generation, demand-response, ancillary services investment alternatives that are possible as alternatives that can implicitly cap the risks associated with longer network development delays. A longer-term focus can also assist in redressing a claimed bias (with which we have some sympathy) that proponents of non-network solutions do not have adequate advance notice of emerging opportunities and have insufficient time to respond to consultations under the current regime.

As noted the status quo described by cl 5.6.6 of the NER may in fact create undesirable incentives for applicants to conceal their proposals for as long as possible. We are not saying that TNSPs do currently act to surprise the industry in this way, and for many reasons that go beyond the scope of the Regulatory Test they may not have a strong incentive to do so, but it remains the case that the current process is structured and implemented in a way that leaves open this possibility. We recommend that the process of administering the test should be constructed so as to deliberately and systematically require/promote early disclosure of possible transmission developments. We note that some TNSPs already provide some strategic guidance, in particular the *Vision 2030* statements from VENCorp.

5.1.4. Implementing a Nationally Focussed Process

Our proposed shift in focus suggests the need for an amended annual planning cycle. We envisage that a series of forward-looking generation/load development scenarios and transmission development strategies will be developed, scrutinised, debated, updated and perhaps, at a high level, “approved”, well in advance of specific transmission development commitments being required. This could take the form of an extension of the current APR and ANTS processes but focussed primarily on longer term and broader strategic issues.[16] These plans and associated scenarios would form the basis for detailed decision making by TNSPs and the basis of the scenarios they must consider in assessing individual projects

16 We would think that strategic development scenarios would have to go out for 20 years, at least.

As described above, the annual planning/consultation process could be undertaken by each TNSP, quite independently of any other. Of itself, then, it does nothing to achieve national coordination, which has been identified as a major failing of the current regime. Alternatively, the process could be undertaken by the AER, if desired, or by a national planner, if one existed.[17]

Three things are necessary, and two desirable, to achieve a more coordinated approach:

- First, some agreement would need to be reached with respect to the form in which scenarios and development programmes were going to be expressed, since otherwise it becomes very different to compare proposals across regions;
- Second, the SOO/ANTS process would have to be re-designed so as to provide long term scenarios in the agreed form; and
- Third, all TNSPs would have to agree, or be required, to use this national scenario set as a common reference point.[18]

Beyond that:

- It would be helpful if the ANST/SOO process were designed so as to at least attempt to highlight differences in approach between TNSPs;[19] and
- It would also be helpful if a central body reserved the right to intervene pro-actively to require consideration of co-operative inter-regional, or trans-regional development options which did not appear to be occurring – this is what the planner of last resort concept achieves.

We believe such a process would be a significant improvement on the status quo, in terms of providing greater certainty to all concerned. It would also afford greater opportunity to propose and consider alternatives, without increasing the likelihood of delay of investment in critical infrastructure. We consider that timely project approval should be much more readily achieved if a project has already appeared in several successive annual programmes and it has been shown how it supports that programme. Through this process stakeholders will have had a number of opportunities to consider the matter, propose alternatives and critique analyses etc. If nothing better has been identified by that process, final acceptance should be more straightforward.

---

17 See Section 6.3

18 By way of contracts, we note that the current test does not require that the scenarios assumed by any TNSP in analysis of any particular project be consistent with those employed by that TNSP in analysing other projects, let alone those used by other TNSPs. We recognise that scenarios may have to be customised and specific sensitivities examined, so as to be able to distinguish pertinent characteristics of the options available in particular cases. But we do believe that any such customisations should at least start from a common set of base scenarios.

19 And we note that neighbouring TNSPs have both expertise and incentive to comment in this regard.

Accordingly, we suggest the whole issue of "project approval", on which the current text of the Regulatory Test is focussed, should be addressed only within this wider framework, whose focus is directed at the strategic programme level. In our view, this implies a need to substantially re-write the Regulatory Test to reflect the process and focus discussed above, along with the generalisations proposed earlier.

We believe this kind of re-development should be pursued, irrespective of whether the "Regulatory Test" really is employed as a test, or not.

5.1.5. Linking service standards and the basis for investment

TNSPs earn a return for investing in assets that are seen to provide value in maintaining reliability or market benefit. The obligations to ensure reliability set clear performance standards in this regard. But what are the standards for market value?

As part of their normal course of business TNSPs arrange for engineering and human resources to meet the reliability standards. Current thinking on service standards related to market benefit appears to be directed towards optimising the value of assets *as built* and linking standards to the effect on the market. However, under current arrangements TNSPs can propose investments that can only provide the full assumed value if ancillary services or network services are acquired by NEMMCO and paid for by market participants. Examples include frequency control services that guard against the effect of failure of transmission lines. Also we have noted the potential for secondary circuit limitations to reduce the capability of primary lines (see section 4.2).

While we support the efforts to create incentives to optimise the effect on the market, we also see benefit in more directly linking the entitlement to earn a return on assets with the costs and benefits that were claimed for the investment at the time of the decision to build was made. This would set a benchmark for the resources a TNSP should have an incentive to employ to ensure the value is delivered. We recognise that changes over time in the configuration of the network, generation, and demand patterns will change the effective capability and make maintenance of the initial capability an unrealistic benchmark. However, the effect of such changes could be taken into account at each regulatory reset. Importantly the incentive we are proposing here should be implemented in a way that does not undercut the benefits of incentive regulation where a TNSP has an approved amount of money within a regulatory period with which to provide a service. In one way or another we would expect to see service standards based on an acceptable level of performance, for example the level of congestion where a TNSP receives no payment but pays no penalty. Our intention here is to suggest a basis for determining that base level.

In section 4 we noted the inherent limitation of assigning monetary values to congestion measures, particularly for outage conditions, and of drawing conclusions about the value of investment to avoid the effect of outages. Service standards should ideally be linked to the effect of outages in a way that creates an incentive for TNSPs to act in ways that mitigate the effect. Such an incentive might be created through congestion management schemes, or by assigning responsibility for provision of a proportion of ancillary services during outage conditions, in such a way as to close the loop between investment and operational outturn. Such a scheme would assist in overcoming a legitimate concern of TNSPs that they do not control the behaviour of market participants that affects market value.

6. OPTIONS TO IMPROVE THE REGULATORY TEST

6.1. OVERVIEW

Previous sections have dealt with high level issues of direction and assessment, and evidence with respect to current performance. In this section, we consider a range of improvements to the Regulatory Test itself, which we summarise below and then discuss in more detail.

We recognise that the AEMC has reached a determination with respect to an MCE proposal on Regulatory Test reform. Our views here are based on the underlying issues and do not attempt comment on the MCE/AEMC work. Our recommendations with respect to the Regulatory Test *per se*, are, however, broadly in line with those being pursued by the MCE and (largely) endorsed by the AEMC. However, we have already recommended a number of further changes relating to the regulatory test process which in summary are to:

- Re-focus the test to provide a robust convergent process to clearly and effectively deal with long term strategic development programmes, and with individual projects only being considered in that context in accordance with our recommendations in the previous section;

- Regularise the test via institution of an annual planning cycle process, rather than a case by case analysis, as currently initiated by NSPs; and

- Improved coordination via tighter linkage to a national SOO/ANTS process.

Here we discuss changes to the test itself, at a more detailed level, and specifically recommend generalisation of the test to deal clearly and consistently with diverse developments that deliver diverse benefits to diverse parties, including market and reliability benefits, private and public benefits and the contribution of non-network elements. We comment on governance matters only to the extent necessary to fulfil our tasks relating to the future of the Regulatory Test as Firecone is addressing governance matters for ERIG.

6.2. GENERALISATIONS TO DEAL WITH DIVERSE BENEFITS TO DIVERSE PARTIES

An important distinction is made in the Regulatory Test between “reliability” and “market” benefits, or more exactly between “reliability” and “market” investment projects. A crucial issue also exists with respect to the treatment of “private” and “public” benefits. These are discussed below.

6.2.1. Reliability and Market Benefits

The current wording of the Regulatory Test implies that projects fall into two distinct categories:

- Investment projects which can only be justified on the basis of “nett market benefits”, which are solely quantifiable in economic terms, and not at all in terms of increased system reliability; and
- Investment projects which can only be justified on the basis of “reliability benefits”, which are solely quantifiable in terms of meeting system reliability standards, and not at all in terms of economic benefits.

Most projects, however, will produce a mix of market and reliability benefits. Thus the distinction drawn by the way in which the Regulatory Test is structured is inherently artificial. If transmission capacity was a one-dimensional commodity, characterised simply by “quantity”, it might be reasonable to argue that the two limbs of the test simply break down the decision so that:

- Enough capacity is built to satisfy reliability standards under the “reliability” limb; and
- Any further capacity which might be justified on economic grounds is built under the “nett market benefit” limb.

Transmission capacity is not like that, however, and transmission system developments cannot be broken down in this fashion. The real situation is much more complex, and the optimal transmission system configuration, and hence the optimal upgrade strategy, may be quite different when both reliability and market benefits are accounted for jointly, from that which appears optimal under either criterion alone.

Even if a single new line is being contemplated, economies of scale often exist that make incremental capacity less expensive if, but often only if, it is built as a single project. It may well be the case, for example, that half the optimal capacity is justified on a reliability basis, and the other half on a nett market benefit basis, even for a simple project.[20] Similarly, if a capacity expansion project is contemplated on a nett market benefit basis, the reliability implications can be significantly different if it is built as, say, three lines of 33% capacity, two lines of 50% capacity, or one line of 100% capacity. Where the project affects an interconnector the different options may have quite different effects on the firmness the SRA units that allow parties to hedge between regions and thus quite different market benefits.

In this latter case, a proper assessment of the economic value of the line should distinguish between the cases, perhaps by assessing the commercial value of firming up SRAs in the case of an interconnector, for example. But, since no explicit economic quantification is required in assessing the benefits of increased reliability, there is no guarantee that this economic assessment will align with that implied by an assessment under the reliability limb of the Regulatory Test. Thus it may well be the case that the optimal configuration determined on a nett market benefit basis should be modified to enhance system reliability and security. Again, it is difficult to see how even this simple decision can be properly considered without combining elements of nett market benefit and reliability assessments.

Therefore, the two limbs of the Regulatory Test should be combined so as to provide a single integrated test, encompassing both aspects. In principle, this is not difficult. A reasonable objective would be *"Minimise the nett market cost of meeting reliability standards".* Where reliability is not an issue, in other words where reliability standards are already exceeded by such an extent that additional reliability has no value (whatsoever), this reduces to "*"Maximise nett market benefit".* But it does allow for reliability benefits to be accounted for, even for a development which is primarily motivated by market benefit considerations.[21] We recognise the potential increase in assessment effort and complexity and envisage a practical grading of requirements commensurate with the significance of the programme.

6.2.2. Public and Private Benefits

An important distinction implicit in the Regulatory Test is that between "regulated" investments that are subject to the test, and unregulated or at least less heavily regulated investments, which may be treated as negotiated "network services" or by MNSPs and are not subject to the test. This distinction is important because it implies a further crucial distinction between the treatment of *public* and *private* benefits.

---

20 As noted earlier this is not meant to imply that there are distinct identifiable assets which perform one function, rather than another.

21 An integrated test would have to deal with the assessment of "reliability benefits", and their relationship to "reliability standards", an issue which is discussed in Appendix B.

The question of how to treat public and private benefits should not be divorced from the question of ensuring a proper balance between generation and transmission investment, each of which has different ownership and exists in a different commercial environment. All projects, including generation, transmission and ancillary services, produce a mix of public and private benefits, either positive or negative. It may reasonably be assumed that any project promises a positive benefit to its proponent(s), but it will almost certainly also affect other participants who are identifiable individually, or as a broad group.

It is common to differentiate between *private* benefits which can be captured exclusively by particular market participants, and *public* benefits which may not be readily captured for a variety of reasons, and typically apply to broader groups of participants. The boundary between private and public benefits can be significantly affected by introducing market, contractual, or regulatory mechanisms which enable the privatisation of what might otherwise have been considered public benefits, for example through transmission rights which would be the result of many congestion regimes including Financial Trading Rights (FTRs) and congestion support contracts (CSPs). If a sufficient proportion of benefits are private, a commercial (market-based) regime could conceivably be appropriate for all generation, transmission, and ancillary service investment. Conversely, the fact that, despite serious efforts to develop such a regime, the *status quo* in Australia, as elsewhere, reflects a judgment that such an ideal is unachievable.

As a result, a somewhat arbitrary line is required between activities governed by competitive market disciplines, driven by the pursuit of private benefit, and activities governed by regulated processes and in which public benefit is supposed to be a consideration. The Regulatory Test in the NEM can be interpreted as drawing that line such that:

- With the exception of “reserve capacity”, generation investment projects are assumed to involve only private benefits, and can be coordinated effectively by commercial market mechanisms; whereas

- With the exception of “entrepreneurial interconnectors”, transmission investment projects are assumed to involve only public benefits, and must be coordinated entirely by a centralised approval process, with regulated cost recovery, because commercial market mechanisms are inapplicable. Note that this applies to both prescribed and negotiated services unless there is an agreement in some form that gives a priority for use of network capacity to a party that pays for a negotiated service.

This does not mean that transmission projects accepted under the Regulatory Test imply the absence of private benefits for any party. In fact, application of a nett benefit test implies an assessment of relevant benefits (positive and negative) summed across all market participants. Application of the Regulatory Test, however, does not involve any attempt to assess the benefits accruing to particular parties, let alone result in those parties being charged for the development in accordance with benefits received. Consequently, there is no assurance that commercial or competitive discipline will be applied to the scrutiny of the proposed costs and assessed benefits.

More exactly, since costs can be borne, in large part, by parties other than the beneficiaries, or at least in proportions quite different from those implied by underlying benefits, the implied incentives to either support or oppose each project are significantly distorted. Incentives which would bring a sharper focus to the design and approval of these projects are diffused, at best, if not subverted so as to produce undesirable outcomes.

By way of contrast, entrepreneurial projects are justified solely on the basis of private benefits accruing to the proponents, and/or any parties contracting with them, irrespective of any assessment of nett market benefit delivered, either in terms of nett market benefit, or increased reliability, as discussed below.

The current arrangements lead to a situation that exactly the same physical project, presumably with the same system and nett economic implications, will be treated quite differently if proposed by different proponents. In neither case is the assessment likely to be ideal.

In our view, consideration should be given to integrating these two approaches to transmission investment planning by:

- Making it possible to consider “mixed” public/private investment proposals, in which some parties are prepared to partially fund, or fund part of, an integrated development by way of a contractual arrangement which reduces the nett residual cost to be accounted for in applying the nett market benefit test; and;

- Adapting the transmission cost recovery regime so as to improve the alignment between the recovery of project costs and the distribution of the assessed benefits that result.

Under such a regime, the concept of an entrepreneurial or regulated “investment” would change subtly, no longer implying a particular physical “investment project” and not limited to MNSP investments, but rather a financial investment by one party to (partially) finance the physical project. It would extend the concept of participant funded investments within the current arrangements.

We are not proposing imposition of a requirement that the use of private funding should result in the creation of assets which are separately controllable, as in the current MNSP provision. Instead, a proposal put forward by a TNSP for “approval” under the Regulatory Test (in whatever form) would simply be in relation to the TNSP’s nett financial investment in the project.

We later discuss the extension and application of this concept in relation to a significantly different "negotiated" approach to transmission system development planning. Even so, the concept of mixed private/public funding is valid, even without proposing any radical change to current arrangements. There are a number of issues to resolve should such a feature be incorporated. Particular care would be required to avoid double counting of benefits.[22]

Arrangements as outlined here may also have potential application within distribution networks where the requirements that may be placed on embedded generators can be a serious barrier to entry. Under current arrangements embedded generators are often faced with paying for "negotiated services" where augmentations to the distribution network are needed to support the connection of the generator. These arrangements appear to be fixed and struggle to recognise the changing mix of public and private benefits over time.

6.2.3. Transmission vs Non-Transmission Alternatives

The MCE/AEMC work has stressed the importance of achieving competitive neutrality between transmission and non-transmission alternatives in conducting the Regulatory Test, and we strongly endorse that perspective and intent. However, we question whether competitive neutrality has actually been achieved, or will be achieved under current change proposals. Three broad issues arise:

- First, there are fundamental differences between transmission and various alternatives, so that they are not strictly comparable;
- Second, there are institutional differences in the way in which transmission and those alternatives are organised, regulated, and rewarded; and
- Third, there seems to be an inherent, perhaps philosophical, bias in the way in which the Rules/Test provisions themselves are structured and written.

Where there are inherent differences, the issue of bias will never be fully resolved. To the extent that the services provided are not commensurable it is not just difficult to achieve competitive neutrality, it is ultimately impossible to say whether it has been achieved.

22 At a minimum, since their preparedness to pay indicates a private benefit accruing to some parties, this would obviously have to be netted off the overall market benefit assessment. But see later discussion.

In many cases, there actually is significant overlap, and that transmission, generation, demand-side or ancillary service proposals deliver sufficiently similar outcomes to be regarded as “alternatives”, at least in the sense that if one proposal is accepted the other(s) should be rejected or materially altered. A number of impediments exist that prevent a true “level playing field” existing for all options in terms of the ways in which they are treated by the market. These impediments are not Regulatory Test issues *per se*, however. Our concern here is that the Regulatory Test and related Rules seem to be written in such a way as to highlight alternatives that could be “approved” or would be expected to be implemented in lieu of the proposed investment.

For example, establishment of the Regulatory Test is dealt with by Rule 5.6.5A, which is followed immediately by Rule 5.6.6. But the latter rule deals solely with the application of the Regulatory Test to *“network transmission assets”* which seems to imply specific physical pieces of transmission equipment.[23] We note that Rule 5.6.6(c)(1)(iii) places the onus on the applicant to identify *“..all other reasonable network and non-network alternatives…(including) generation options, demand side options, MNSP options…” .* Rule 5.6.6(c)(4) requires the TNSP to rank these alternatives. Further, the process allows other parties the opportunity to propose other alternatives and/or challenge the applicant’s ranking. This is all desirable, and commendable, even if the applicant and other participants have weak or distorted incentives to rigorously critique and challenge a TNSP proposal. But merely identifying and assessing non-transmission alternatives does not address the fundamental issue that transmission and generation parties do not engage on an equal or symmetric footing with respect to investment proposals. And, while the test itself does suggest that it might be applied to projects other than *“network transmission assets”,* the Rule does not explicitly suggest that such alternatives might, themselves be, or constitute part of, a proposal under the Regulatory Test.

While the materiality of this asymmetry is debatable, the implication is that non-transmission proposals cannot receive the same level or kind of regulatory approval as transmission proposals, or at least that it is not clear how they can. The possible implication is serious, particularly if a proposal that passes the Regulatory Test is presumed to have regulatory approval of the associated expenditures. The implication is less serious if the Regulatory Test is not assumed to confer regulatory approval of the expenditures, that is it remains a consultative process as it is now.

23 The term is italicised, but does not actually seem to be defined in the glossary.

There are non-trivial issues involved in establishing a strict comparison.[24] Consider, for example, the hypothetical case where a transmission investment proposal and a generation investment alternative deliver identical benefits in terms of both reliability and market benefit. If the generation investment is expected to operate on a purely commercial basis, it must surely be disadvantaged relative to regulated networks. This is because, unless it operates under a regulated generation arrangement, it has no readily available regulated mechanism to recover costs and because the nett market benefits are, at best, a risky prospect for a number of reasons, including the very fact that market design and implementations change over time. So the "risk-adjusted" discount rate that a generator might apply to its decision is very likely to be higher than the discount rate a regulated NSP might be expected to (or is forced to) apply.

Regulated transmission investment could therefore consistently pre-empt and crowd out otherwise equivalent generation investment. In terms of the Regulatory Test, this would occur as the transmission proponent considers the competing generation investment, and concludes that, while it may be optimal, if assessed at the same discount rate, it will not be assessed at that discount rate by a market participant. Thus it could be reasonably claimed that it would not actually proceed, or at least not in time to avoid a regional capacity shortfall which can only be met by expanding transmission capacity.

The Regulatory Test tries to avoid this problem by requiring that projects be assessed and compared at a "commercial discount rate", and this is probably intended to mean the kind of discount rate which would be applied by a commercial investor in generator capacity for energy market purposes. Thus, while the regimes applied to generation and transmission are clearly different, and we might argue about the discount rates which should be applied, there is not necessarily a major discrepancy in the way these two categories are treated, in energy market terms.[25]

Reliability benefits, on the other hand, present a very different situation. Consider that:

- The implicit value of meeting a reliability standard can differ from the value placed in the energy market on additional generation to meet that standard. More importantly, once determined, a transmission investment can be made and its costs and risks recovered under a regulatory regime that effectively represents a contract that uses value from those reliability benefits to justify the project. A generation investment may have no way to contract for the full value of the reliability benefit created, at least not via normal commercial arrangements presently available in the energy market; and

---

24 And noting that the Regulatory Test currently assumes and requires that such comparisons can be performed.

25 There is another discrepancy, in that transmission investment can be partially justified by the extent to which it improves competition, and no equivalent benefit in terms of regulated cost recovery is available to subsidise generation investment which achieves the same goal. On the other hand, it can be argued that, in theory, consumers who believe the market to be uncompetitive in their area should be collectively motivated to pay a premium to subsidise entry which increases competition.

- The risk involved in generation capacity investment designed to meet loads during contingencies occurring with the rarity implied by the reliability criterion involves a wide range of risks that ultimately imply a higher discount rate or other adjustment to reflect cost recovery risk. The effective discount rate which might be applied to such investment will be correspondingly high and, even where generation investment would otherwise be preferable to transmission investment (when assessed at the same discount rate); the transmission investment is preferred because it enjoys a privileged position under the regulatory regime.

It might be argued that the Regulatory Test provides the means to avoid this problem by simply using a discount rate that compensates for these types of risks. But, in reality, we think it unlikely that reliability projects, in particular, will be assessed at such high discount rates, and nor would that be compatible with the NSP's commercial incentives, or with the reliability standards themselves.[26] Thus it seems more plausible to argue that a "level playing field" can only be achieved if a similar regulatory option is available for generation as for transmission proposals, in situations where it is providing equivalent benefits to potential rival transmission projects. A later section discusses options to achieve this, but here we simply note that if the Regulatory Test is seen as part of the process by which regulatory approval is given, it should be generalised so as to clearly apply in an even-handed way to all types of proposal.[27]

No matter what role the Regulatory Test is intended to play, competitive neutrality cannot be sustained if the test itself, and associated rules, are not structured and worded so as to treat all comparable options in an even-handed fashion. It has been suggested that the industry will adopt a common sense attitude to diverse proposals, and that ways have been, or will be, found to interpret the test and rules so as to allow such projects to be considered. That may well be the case, if and when such projects surface. But if the goals of this process include the identification and even handed assessment of good alternative projects, a first step is for the arrangements to be freed from any implication that it is founded on "transmission assets", i.e. physical objects, rather than the achievement of certain *outcomes*, with respect to both reliability and nett market benefit.

---

26 Since relatively high discount rates can make it optimal not to invest in the capacity required to provide high levels of reliability.

27 This argument does NOT by any means imply that all generation investment should be brought into an integrated and regulated regime, under an expanded Regulatory Test. Note that the hypothetical cases discussed above involved generation and transmission investments which yielded equivalent benefits. Transmission obviously provides benefits which can not be provided by generation, and vice versa. In fact the primary benefit delivered by most generation investment is energy production, and this aspect of any "nett market benefit" is basically rewarded by the energy market. The issue here is in relation to these additional benefits.

6.3. Issues of Regulatory Structure

In this section, we consider the role the Regulatory Test might have under various alternatives, and the implications that role may have for the form and structure of the Regulatory Test itself, and of associated processes.[28]

We suggest that a strategic choice is required and the linkage between the Regulatory Test and the regulatory reset process should either be:

- Strengthened, so as to match the apparent intent of the way the test is written; or
- Abandoned, so that a more appropriate (non-test) process can be designed to achieve a different purpose.

We believe the Regulatory Test, and associated processes recommended in the previous section could be made compatible with either approach.[29]

We also examine the possibility of a process involving greater interaction between TNSPs and participants, on a more equal footing. Such an enhanced process would involve a further generalisation of the Regulatory Test for application within a significantly different context.

6.3.1. Role of Regulatory Test under Alternative Structures

Previous sections have recommended proposals with respect to the reform of the Regulatory Test on the assumption that it is supposed to form part of a regulatory process whereby "approval" is ultimately given to expenditure on particular projects and hence to cost recovery, too.

On the other hand, the currently regime involves determination of a revenue cap based on a 5-yearly reset process, in which cost recovery is based on actual and projected expenditure, with no direct reference to the Regulatory Test at all.

---

28 This section is not intended to address the broad issue of the form and structure of regulation at the national level, or to consider the arguments for or against various alternatives.

29 This section assumes the current structure with a number of separate regional TNSPs. We have not given detailed consideration to the more radical option of amalgamating TNSPs into a single national body. But we note that does not greatly alter the situation except to internalise the need for "national coordination". The option still exists to have a national planner responsible for project commitment, and interacting iteratively with the national TNSP, via the Regulatory Test process. Indeed this is essentially the current structure in New Zealand, for example. Or the regulator could simply require the national TNSP to adopt an essentially similar process, as in the Planning Process Requirement approach discussed below.

Given this regulatory context, it is fair to ask the question: what does it mean to *pass* the Regulatory Test? It does not mean that the corresponding expenditure has been “approved” (or even scrutinised), *ex ante*, if only because there is no provision for a formal body to approve it. On the other hand, it (arguably) does mean that an appropriate planning/ consultation process has been undertaken, and that due consideration has been given to alternatives. The Regulatory Test therefore could be re-named to reflect that it is simply a “Planning Process Requirement”.

The nexus between this Planning Process Requirement and incentive regulation under the regulatory re-set process could be that:

- *Ex post* treatment of expenditure on particular projects is influenced by (the degree of) compliance with conclusions from this ‘Regulatory Test” process; or that

- Projected expenditures are based, ex ante, on the forward-looking programme(s); and/or

- Treatment of the TNSP overall is influenced by judgments with respect to the way in which it has managed its consultation/planning processes.

With respect to these possibilities:

- If the regulatory regime relied on *ex post* cost reviews, it would be reasonable for a regulator to dis-allow cost recovery (or at least introduce cost recovery risk associated with a fresh review) of expenditures which had not been “authorised” via the Regulatory Test process, or to disallow or review afresh any cost overruns that arise when developing the project. However, such a process sits uncomfortably with the current regulatory reset process for various reasons, including the inconsistent temporal matching of the current *ad hoc* Regulatory Test “cycle” and the 5-yearly reset process. This mismatch could be reduced in the event the recommended annual planning cycle were adopted, but the mismatch still implies uneven treatment of projects proposed at various points in the regulatory cycle, and creates incentives for gaming that timing;

- Forward expenditure estimates must presumably be based on forward investment programmes, so they would surely reflect the programmes being consulted on via the planning process proposed earlier; and

- A TNSP which acquires a reputation for poor planning and/or consultation processes would presumably run the risk of being treated less generously during the regulatory re-set process.

An alternative approach would entail an expected cost and an upper bound cost to be determined as part of the regulatory test process. Actual costs within the upper bound would still be allowed, but costs in excess of the upper bound would not be allowed without further detailed justification (prudence review). The fundamental prudence question is different in such a situation. Given the passage of the regulatory test by an investment that was expected to cost "X", is it prudent to allow recovery of costs "Y" (where Y greatly exceeds X). If the test would not have been passed had the higher costs been known, then this is a potentially legitimate concern. Valid reasons may exist about why the costs have swollen to such an extent, but these reasons need to be vetted to ensure that there are adequate pressures on the TNSP to propose cost estimates as part of the regulatory test process that are reasonably robust.

6.3.2. A Negotiation-Based Framework

Section 6.2.3 discussed how transmission and generation parties do not currently engage on an equal or symmetric footing with respect to investment proposals. We suggest that this asymmetry favours traditional transmission system development over any alternative. Although generalisation of the Regulatory Test can alleviate some of these concerns by creating a somewhat more level playing field, these issues cannot be fully resolved without a more radical set of changes.

A nationally coordinated transmission planning process could instead be developed so as to provide the context for a more market-orientated and interactive approach to generation/transmission system development planning.

The current process is one in which non-TNSPs make submissions in relation to a TNSP proposal that effectively relies on non-proponents acting as objectors. At least in principle, a national coordination regime could be implemented quite differently, with the primary interactions taking the form of negotiations amongst TNSPs and market participants (including MNSPs). Such a process would depend on the existence of a national planner to serve as process coordinator. The national planner would need to have the ability to arbitrate and impose solutions, and cost recovery arrangements, where agreement could not be met.

As part of such an approach, acceptance of the concept of investment proposals with mixed public and private impacts would be crucial. Negotiations would have to take place in a much more commercial context, in which participants were really expected to cover the costs of the transmission developments from which they felt were justified, and thus were seriously motivated to debate those benefits, and to propose lower cost solutions. Thus, while we believe the proposals made to this point could be readily implemented without significant changes to the current structure, this latter proposal falls more into the category of possible future developments and would only be justified in the event it could be shown that costs were outweighed by benefits.

In terms of the potential impact on the Regulatory Test, we believe the basic outlines of the process, in terms of an annual planning cycle focussed at the programme level, would not change. The major issue involves the division of the "national planner" function into a coordinator role and a negotiator role, which could (and would preferably) be undertaken by different entities. It is doubtful that individual participants will be prepared to fully fund projects which are deemed necessary to meet reliability standards, in particular. Thus, if our proposal to allow mixed private/public funding were accepted, we envisage the need for some degree of regulated funding to secure commitment of many such projects. This implies the need for some body to be empowered to negotiate on behalf of the "public interest", and such negotiations will only be meaningful if that negotiator actually controls some part of TNSP revenue for that purpose.[30]

Such an arrangement implies the need to think carefully about the objective of the regime. In the limit, "nett consumer benefit" would be an appropriate criterion to be applied by any party negotiating on behalf of consumers, for example. This is not different from the situation with respect to commercial negotiations in any market, or inconsistent with the overall goal of maximising nett market benefit. What is different is that the mechanism by which nett market benefit is supposed to be maximised shifts from one of top-down optimisation, to one based on commercial negotiation between self-motivated parties.

The market does not divide neatly into two groups, with generators solely gaining private benefits, and consumers solely gaining public benefits. The extent to which any party is prepared to pay may be taken as indicating an expectation to benefit from price changes which of themselves, may only indicate wealth transfers between participants, rather than changes to nett market benefit.[31] It may even be argued that this "second order "gain could motivate one party to cover the entire project cost even though the nett market benefit was negative. As we have already noted the same situation may apply in any market, and the same motivations arise. Our preliminary assessment, based on prior work elsewhere, is that the equilibration through contracts is an important mechanism to mitigate any negative effects. However, we have not undertaken a detailed assessment in this matter.[32]

30 Perhaps by collecting and disposing of a pool of levy funds, or by reverting to a model in which regulatory approval is given for TNSP expenditure for such purposes.

31 See section 4.2.1

32 The issue was addressed by E.G. Read: "Pricing and Operation of Transmission Services: Long Run Aspects". In A Turner (Ed) *Principles for Pricing Electricity Transmission*, Trans Power New Zealand, August 1989. It was concluded that, provided non-market mechanisms could not be employed to block such developments, equilibration of energy and transmission hedge contract markets should ensure that "interconnector" projects only proceed if the nett benefit was positive. But that was in the context of a simplified LMP market.

We recognise that such a concept falls short of a fully commercial market ideal, and that it would also represent a significant change. Thus caution is appropriate on several grounds, and significant further analysis and consultation would be required before making a firm recommendation to pursue development of this option. Still, we consider that, if the advantages of introducing more competitive market pressures into transmission planning are accepted, this kind of hybrid proposal probably represents the best prospect of achieving that goal, and allows it to be achieved to the maximum extent possible, given other legitimate constraints and considerations.

Table 3 provides a summary of impact of each of the recommendations against the assessment criteria in the same form as assessment of the current arrangements in Table 1

Table 3 Impact of recommendations on assessment criteria

CRITERION	IMPACT OF RECOMMENDED CHANGES ON ASSESSMENT CRITERIA
National v Jurisdictional Focus	Changes to shift the focus of planning and assessment to longer term and nationally focussed programmes and should be a prime objective of whatever governance arrangement is selected - in effect extending and enhancing the ANTS process. These, long term programmes would inevitably be key elements in setting both capex and opex components of approved revenue caps. Programmes should be updated annually and demonstrate national consistency across a common set of scenarios for assessment of individual project expenditures.
Compatibility with market based investment and trading	Assessment of investment options should recognise that potentially there are both reliability benefits and market benefits, both “public” and ‘private”, in all investments and operating regimes Consideration may be given, longer term, to introducing a framework placing more reliance on commercial negotiation, as discussed in the next section
Investment planning	In addition to the elements of national focus and longer term programmes, individual project/expenditure assessment should start from demonstrating how it supports the longer term programme.
Operational Incentives	As TNSPs are not the only influence on network performance, incentives should be given to TNSPs with respect to the actions they should undertake to maintain performance of national flow paths and in particular interconnectors (for both the existing network operation and new investment). Linking service standards and associated performance standards to the capacities used for the Regulatory Test (whether it be renamed as a consultation process or strengthened as a regulatory approval process) will link operational performance to the cost benefit analysis that the TNSP adopted to justify the investment
Neutrality	A shift to longer-term programmes updated annually should extend to the level where advance notice of opportunities for non-network alternatives is also available The test itself, and related rules, should be re-written in a way which treats all types of proposal in a much more neutral manner. Assessments and financial arrangements for non-network facilities, in particular generation, should ensure similar financing burdens are placed on all alternatives – for example discount rates and length of contract for generation options, to remove any inherent bias afforded to regulated network alternatives
Transparency and Information	The focus on long term programmes will afford parties additional time to assess and prepare for emerging opportunities. While the Regulatory Test remains a “non-approval” consultation process, it has a role as a key informational instrument with respect to both programmes and individual projects/expenditures, both for participants and for regulatory authorities and processes.

6.4. Complementary Developments

6.4.1. Overview

Our discussion of the Regulatory Test has naturally focussed on change to the Regulatory Test itself, and associated processes. We have also been asked to comment on *"… other or additional regulatory or pricing mechanisms (which) are required to move towards an efficient mix of transmission and well located generation investment in the longer term?".* Obviously the nature an extent of any 'additional' requirements depends significantly on the way in which the regulatory environment for transmission is developed from this point forward. We have therefore addressed this question by considering other developments which would complement our main recommendations.

We outline some issues relating to two broad areas:

- Achieving competitive neutrality between transmission and alternative technologies; and
- Introducing some form of locational and/or constraint impact based pricing.

These are discussed below.

6.4.2. Competitive Neutrality

We have already noted, and strongly endorsed, the importance placed by the MCE/AEMC work on achieving competitive neutrality between transmission and non-transmission alternatives. In this regard we have recommended changes to the form and wording of the Regulatory Test which would assist by providing that all such alternatives be treated on a non-discriminatory basis.

We have also suggested that this will not, of itself, create a level playing field between various options, and hence implicitly that complementary changes might be required. This situation is not by any means unique to Australia, and achieving a level playing field between generation and transmission options is a universal problem in de-regulated electricity markets.

The relative risk faced by the two different types of investment is a fundamental issue. This relative risk difference has nothing to do with the actual economics, or risk profile, of the physical generation or transmission technology. As a practical matter, if a transmission and (thermal) generation investment have the same expected cost and benefits, the generation investment would likely have lower risks to the extent that a large part of its expected cost consists of fuel, which need not necessarily be consumed if it turns out to be uneconomic at a later date.[33] Thus, if generation and transmission developments provide the same benefits, a lower discount rate would apply to transmission simply because of the characteristics of the regulatory regime under which it operates not because it is inherently less risky.[34]

Although we note the Regulatory Test requirement that a “commercial discount rate” be applied to all options, we have argued that requiring a TNSP to assess projects at a discount rate significantly higher than its own natural rate creates its own consistency issues, particularly with respect to reliability projects which, from a commercial perspective, would be very risky. Accordingly, we suggested that a “level playing field” can only be achieved if a similar regulatory option is available for generation. That is, a mechanism needs to be found which allows some or all of a generation investment to be granted regulated cost recovery where it is providing equivalent benefits to potential rival transmission projects. An extension of network support contracts would be worth exploring in this regard.

Similar considerations apply between transmission and demand side or ancillary service options. Markets for generation are at least well established and consistent across the NEM. But markets for demand side response and/or ancillary services seem less well developed, and more fragmented but are possibly the most cost-effective competition to physical transmission system developments. For example, system reliability and effective transfer capability may be significantly enhanced, at relatively low cost, by establishing an inter-trip arrangement with a major load. This could be classified as a demand side response or a network support ancillary service.

In part, support for such options may be provided by an extension of the current “network support” contract. We have not investigated the availability or performance of such arrangements under the status quo. However, we note that current arrangements would likely involve the need to negotiate an agreement with a monopsonist TNSP which is likely to be promoting a competing transmission system investment. It seems inherently unlikely that this will provide a truly level playing field, or that this mechanism will provide the kind of long term security currently afforded regulated transmission investment under the current arrangements.

---

33 The extent of the advantage may be reduced by long term fuel contracts, but the direction is clear.

34 In fact, essentially the same situation applies when an MNSP and TNSP propose identical projects. It seems clear that access to regulated low risk funding, and the ability to effectively get cost recovery for reliability benefits, gives the TNSP a competitive advantage. Ad, if competitive neutrality can not be achieved in this case, it seems unlikely that it can be achieved between regulated transmission and generation.

Remedies for this situation lie outside the present scope, but we note that consideration could also be given to mechanisms employed, or proposed, elsewhere, such as the CSP/CSC arrangements, and various forms of (regional) capacity payment or capacity ticket regime, as discussed below. We also note the desirability of fostering a constituency to promote alternatives to traditional transmission investment.

6.4.3. Locational/Constraint Pricing

Since the current Regulatory Test regime, and all the variants we have discussed, relies heavily on market participants actively participating in the transmission system planning process, the motivation of those participants is crucial.

Developments designed to better incentivise participants provide an important complement to the proposals we have made with respect to the Regulatory Test regime, and particularly to those proposal which place greater reliance on participation.

Energy Pricing

Fundamentally, the market benefits attributable to transmission derive from its ability to move electrical energy between locations, and the economics of transmission system development are at least implicitly driven, to a large extent, by differences in the cost and value of electrical energy at various locations.

The NEM market design does recognise and reflect this, at a broad regional level, but does not employ any systematic form of intra-regional locational energy. Accordingly, it does not attempt to use energy prices to incentivise intra-regional locational decisions for either transmission or generation. But the assessment of nett market benefit under the Regulatory Test must obviously depend on the precise location of any proposed development, and this applies to both intra-regional and inter-regional developments since, in practice, they are not physically distinguishable. In this respect, then the transmission planning arrangements actually provide locational “signals” which are superior to those provided to other market participants by the energy market. Consequently, we can not expect to achieve *an efficient mix of transmission and well located generation investment in the longer term,* unless equivalent intra-regional locational signals are provided to generation.

In principle there are two ways in which this might be achieved via energy pricing:

- First, there is a well established theory relating to ”Locational Marginal Pricing” (LMP), which in the limit, becomes “nodal”, and to “Financial Transmission Rights” (FTRs) which allow inter-locational contracting, and can at least partially incentivise and support transmission development in that context.

- Second, CRA has previously proposed a different, but in the limit conceptually consistent concept involving “Congestion Support Payments” (CSPs) and “Congestion Support Contracts” (CSCs), and this has recently been trialled at one location in the NEM.[35]

It will be evident that any assessment of these options involves a broad range of issues including the treatment of regional boundaries, and the treatment of transmission constraints arising within and between regions, both in terms of dispatch and pricing. CRA has previously reported extensively on some, but not all, of these issues, and suggested the limited application of CSP/CSC mechanisms as a way forward, given the current state of development of the NEM transmission network. These issues are the subject of a separate ongoing review, by the AEMC.

The basic point remains that a truly “level playing field” between generation and transmission cannot be achieved unless or until one of these options, or one of the alternatives discussed below, is adopted.

Transmission Pricing

Any form of locational transmission pricing will give locational price signals which must imply both operational and locational investment incentives for individual participants. While these may not be accurate, or always desirable, they must be taken into account in assessing the overall impact of any regime, whether energy pricing is simply regional, or involves intra-regional detail via either the LMP/FTR or CSP/CSC frameworks. Thus, in principle, the transmission pricing regime should be designed work in conjunction with locational signals provided by whatever energy pricing regime is adopted.

This could be achieved by:

- A competitive market approach, under which market participants contract to pay for the transmission assets they expect to benefit from, or
- A regulated approach, calculating some form of forward looking LRMC signal.

In theory, the former can be shown to be “ideal”, but it has not proved practical to implement anywhere. Furthermore, it might be thought possible to calculate price signals under the second approach which at least approximate ideal market signals, but this has not proved possible either.[36]

---

35 We understand that a third “Constraint Based Rental” (CBR) proposal has recently been advanced that employs similar concepts.

36 There is a fundamental problem with the dynamics of pricing. The ideal market signal being derived from (forward looking) expectations of the situation which will apply once (backward looking) contracts have been agreed, and this can not be reproduced by any “price” signal based simply on current (or past, or expected future) consumption alone.

In practice, we suggest that a negotiated hybrid public/private transmission pricing regime, matching the negotiated hybrid public/private transmission planning regime discussed above, is a practical approach although not without practical and political difficulties.[37] Such issues are the subject of a separate ongoing review, and are therefore not considered further in this context.

An ideal "level playing field" between generation and transmission cannot be achieved unless some form of intra-regional locational pricing is adopted. Furthermore, even if one of the energy pricing options described above is adopted, the full impact of such an option cannot be assessed without also considering transmission pricing, the effect of which may complement, distort, and perhaps overwhelm, the energy pricing signals.

Capacity Pricing

A third option is to extend the concept of network support contracts on a locational basis. This would involve offering a payment to generation to locate at particular points in the network so as to reduce the need for expensive transmission system development to a greater degree than now.[38]

Sophisticated variants might include payment of locational capacity premia or establishment of locational capacity ticket markets but all generally involve some greater degree of central management of the NEM. The energy market could continue to operate as at present, but with additional revenue being available to support peaking capacity, via payments for capacity tickets defined as call options operative above some moderately high strike price, and those call options could be held by consumers, or by retailers on their behalf, as protection against spot market price spikes. Consumers are already free to enter into such contracts, but the assumption here is that the reliability standards imply that generation/transmission capacity actually has more value than the market is prepared to freely pay, via such contracts.

In the NEM such market based capacity ticket arrangements might be developed at a broad regional level, comparable to the granularity of the existing regions. In the regional structure of the NEM they seem unlikely to be developed at a more localised level, except perhaps via the CSP/CSC mechanism.

37 Apart from anything else the "ideal" price signals are quite dynamic, alternating between periods before transmission expansion when prices should be largely based on current consumption, and periods following expansion, when large fixed cost recovery components are appropriate, irrespective of actual consumption.

38 Or potentially charging a penalty to discourage generation from locating in an undesirable location.

Ancillary Service Pricing

Ancillary services are a diverse collection of sometimes ill-defined "services" which do not quite fit into either the generation or transmission categories. They include FCAS and NCAS services, technical services like reactive support and black start capability, but conceptually also services like energy reserve capacity. In part they have been integrated with the energy market, for which NEMMCO is responsible. In part they have been integrated into the transmission/distribution sectors, for which TNSP/DNSPs are responsible.

There are, however, significant overlaps between the services and only FCAS is fully integrated with the energy market. A number of ancillary services, in particular FCAS can be essential to delivering the full capability of the network but TNSPs have no accountability or control over the procurement or dispatch. TNSPs reasonably cannot be fully accountable for their own performance while they are unable to manage such services. Performance incentives need to be limited to what a TNSP is able to control and in the longer term investment requirements may assume a TNSP is responsible for investments or at least long term contracts for ancillary service support.

Constraint Based Pricing

We have previously argued that, whereas the LMP/FTR framework at least theoretically allows integration of energy and transmission markets, the CSP/CSC framework has the advantage of extending this concept to allow consistent treatment, and competitive pricing, of ancillary services which support the network by enhancing inter-regional or intra-regional transfer capability.[39] Elsewhere we have shown how this framework can be used to incentivise provision of such services, both in the short and long term, and to simultaneously "firm up" the hedging available via the SRA process. Thus it can be viewed as providing a form of network support contracting, which could supplement, or supplant, some such arrangements existing under the status quo.

Again, this relates to a broad range of issues including the treatment of regional boundaries, the treatment of transmission constraints arising within and between regions, and the status accorded to CSP/CSC arrangement and other forms of network support contract, which are the subject of a separate ongoing review. However, we do suggest that this proposal should be given further consideration, as a potential means of integrating at least the key locational aspects of the generation, transmission and ancillary service markets.

In summary, we note that:

---

39 Noting that this generalised concept is no longer strictly "locational", since the precise location of ancillary services is not necessarily the critical issue with respect to transmission system support.

- Irrespective of any structural or process changes, the focus of arrangements for transmission, and in particular the Regulatory Test, could be improved by generalisating them to deal consistently and even-handedly with proposals involving any combination of:
    - Private and public funding;
    - Transmission, generation, demand side or ancillary service elements; and
    - Market and reliability benefits
- The regime could also be improved by:
    - Imposing a requirement to institute an annual consultation/planning cycle;
    - Re-focussing on long-term strategic developments issues and programmes; and
    - Only considering specific projects in the context of such programmes.
- The Regulatory Test process could also be significantly improved by:
    - Requiring TNSPs to base their analyses on a consistent set of national planning scenarios produced by an extended SOO/ANTS process; and
    - Reserving the right for a relevant body such as the AER or AEMC to identify, and require consideration of, inter-regional developments which appear to have been overlooked by the TNSPs involved. In effect, continuing the planner of last resort philosophy.
- The precise role of this modified Regulatory Test would depend significantly on the option chosen with respect to regulatory structure, and philosophy, at the national level.
    - If the Regulatory Test is really to perform a *regulatory* function, the process described above should be seen as constituting a regulatory approval process. If so, it would sit most naturally with a national planning body that approves individual project commitment decisions.
    - But this is not the current regulatory structure, and sits awkwardly with an incentive-based regulation philosophy. In the current context, it should therefore be interpreted as a “Planning Process Requirement”, and should be re-written in that vein;
    - Beyond that, we suggest a negotiated approach to transmission system developments. A number of significant changes, including acceptance of mixed public/private developments, the establishment of a national coordinator and/or negotiating agent, and significant changes to transmission cost recovery would be required to achieve such an outcome. Such a framework is suggested for

consideration as a longer-term development, rather than for immediate implementation.

- These proposal with respect to the Regulatory Test, and associated processes, would ideally be complemented by:

  - Developments to enhance competitive neutrality between transmission and non-transmission alternatives by increasing the ability of the latter to obtain long term, low risk, financial support, where providing equivalent services; and

  - Developments to provide more appropriate commercial signals to participants – signals that better reflect constraint impacts, including both “locational” and ancillary service impacts -- most probably through some variant of a CSP/CSC regime.

APPENDIX A: TERMS OF REFERENCE

1. Conduct a review of the current position in respect to transmission services in the NEM addressing, in particular, the extent to which the current regulatory regime provides appropriate incentives to deliver efficient behaviour in the short term provision of transmission services and in the longer term investment in their network.

   The consultant should develop a simplified industry participant model to assist in quantifying the likely commercial impacts of the current regime and consider available evidence on the outcomes to date.

   In considering the performance of the transmission network services to date, the consultant should also:

   a. Consider whether the transmission services supplied to the market have been supplied on as “firm” a basis as they should have been considering the difference in value to reliability/security and financial/retail markets of more certainty as opposed to more capacity.

   b. Determine whether the current regulatory arrangements have provided adequate incentives to find and implement non-network solutions in seeking to deliver reliable supply to customers.

   c. Identify any examples where there has been an economic cost to the broader market because of the standard of transmission services provided to the competitive market and any lack of incentive or sanctions in the current regime.

2. The need for certain investments to pass the Regulatory Test is part of the regulatory regime. Assess the role and importance of the Regulatory Test in driving efficient investment within the current regulatory regime.

3. Analyse the current arrangements for the recovery of transmission revenue. What incentives do these pricing schemes provide for efficient operation and investment by network owners or utilisation by generators and customers?

4. To what extent do the current arrangements provide appropriate mechanisms and adequate incentives to efficiently invest in the interests of the national grid as a whole rather than the network service providers own network or transmission region?

5. How are changes to the Rules and regulatory arrangements now in progress expected to modify incentives and change outcomes?

6. Consider the future development of transmission services in the NEM addressing:

a. How can arrangements be improved to deliver more efficient utilisation of the current network?

b. How can the arrangements be improved to deliver more efficient investment outcomes in the future both in transmission and in generation:

- within the shared network and under the common carriage approach, how can we determine the costs and benefits of transmission and efficiently develop the power system in a market context?

- can the regulatory regime be improved to deliver a more predictable framework to develop the grid which improves certainty for generation investors?

- can the regulatory regime be improved to deliver an effective framework to develop the grid to meet the needs of efficient generation investment whilst maintaining the third party access regime?

- to what extent should the system provide opportunities for network developments to be driven by individual market participants and would this increase market efficiency?

7. Should the regulatory test be modified or its application changed to drive more efficient outcomes in the future?

8. What other or additional regulatory or pricing mechanisms are required to move towards an efficient mix of transmission and well located generation investment in the longer term?

APPENDIX B: RELIABILTY BENEFITS VS RELIABILITY STANDARDS

In practice, the biggest conceptual problem with achieving an integrated test is that reliability standards are currently expressed in physical, rather than economic terms. The current physical expression does not necessarily prohibit an integrated assessment of some projects, however. If the reliability standard is treated as a lower bound on performance, then a project which exceeds that standard can be considered on a "nett market cost" basis.

Given the existence of significant economies of scale and scope, for example, it may be that the configuration of a project that satisfies reliability requirements at least cost would be altered so as to include extra capacity and/or components, the incremental cost of which is less then the incremental market benefits.[40] Including those additional components minimises the nett market cost of meeting the reliability standard, and this, we suggest, provides a broadly appropriate conceptualisation of the cost to be minimised for such an investment.[41]

The analysis described above should ideally also account for additional benefits due to improved reliability, in excess of the standard. Similarly, consideration should be given to the possibility that it can be optimal to relax a given standard in some way, in some places, at some times of the day, in some seasons of some years, under some scenarios.

A graded approach to standards is inherent in other areas of the NEM. The concept of "soft constraints" is used to grade the requirements for FCAS in dispatch and there is an allowance of up to 30 minutes for return of the overall power system to a "secure state" after a contingency event. We also note that some scenarios are able to have reliability below the standard so long as reliability is achieved in the majority of cases. However, no costs are defined to enable assessment of the impact of such variations from the standard, in either direction.

---

40 In reality, the inclusion of such additional capacity is inevitable, if only because transmission augmentation occurs in a "lumpy" fashion, while transmission requirements vary continuously over a variety of time-scales. Thus, if a project is built so as to just satisfy some standard at some time of the day, in some season of some target year in some scenario, it will inevitably exceed the standard at other times of day, in other seasons, of other years under other scenarios.

41 This is actually explicit in the New Zealand "Grid Investment Test", but is unclear in the NEM Regulatory Test, from which the New Zealand test was derived. In the Australian test, the definition of "cost" does not seem to include "nett market costs' in the sense discussed above, although these might arguably constitute an *"other costs which are determined to be relevant*….", under Clause 2(d).

Some may argue that a graded approach is inappropriate because reliability is not an economic issue, and should not be compromised under any circumstances. However that implies that the value of incremental additional reliability is zero and infinite for any decrease in reliability below the standard. We find it difficult to accept that a plausible argument can be advanced for zero/infinity valuations as a measure of the economic cost/benefit of deviation from the standard especially as the standard themselves do not reflect economic assessments, so the step change in value of incremental reliability occurs at an essentially arbitrary point in the reliability spectrum.

We accept the practical difficulties inherent in agreeing on specific values or relationships, however, the Regulatory Test should at least conceptually recognise that variations in reliability, even around a specific standard, do have an economic value. Conceptually, this logic implies the need for an integrated “nett market cost” based Regulatory Test in which such incremental and decremental reliability values are treated as “market benefits”.

Practically, the initial values employed for incremental and decremental reliability impacts could be set to near-zero, and near-infinite levels respectively, in which case the integrated test would approximate the present test for reliability assets, when applied to projects which truly do not yield any appreciable market benefit. A near-infinite reliability value for sub-standard reliability would force projects to be built to at least meet reliability standards, with any extra capacity being justified on nett market benefit grounds.[42] Over time, however, more reasonable values should be developed, preferably in the form of a graduated scale, depending on the extent of deviation either side of the specified standard.[43]

42 Again stressing that we are not suggesting that projects be thought of as having reliability and market benefit components at the physical asset level.

43 But we do not recommend the adoption of a single value, to be applied to both increments and decrements, because this reduces the problem to a purely economic assessment, with no significance at all being attached to the standard itself.