28 October 2010

Mr John Pierce
Chairman
Australian Energy Markets Commission
Sydney

Dear John

**AEMC TRANSMISSION FRAMEWORKS REVIEW - SUBMISSION**

I refer to my letter on the above dated 4th October 2010. As stated therein, we are pleased to have the opportunity to make a submission to the AEMC's Transmission Frameworks Review Issues Paper.

As also stated, we look forward to a constructive debate in the course of this review and wish you well in building on the recommendations arising from the Climate Change Review.

In my previous letter, we drew your attention to the fact that our submission has been partly funded by the Consumer Advocacy Panel and that a condition of their funding is that the report is sent to the Panel before its public release in any form for any comments by the MCE Secretariat. In the case of our submission, there were some comments provided by the MCE Secretariat for our consideration. We have duly considered those comments and this has caused us to make the following minor changes to the submission (reflected in the attached version):

- 2.9% has been changed to 3.9% towards the bottom of page 4 (this was a typographical error that lead to one of the comments made by the MCE Secretariat); and
- footnote 2 on page 4 now refers to pages 76 and 77, not just 77 as previously.

The Secretariat also questioned our analysis of energy growth rates. We reexamined our analysis which was based on AER data and continue to believe that it is correct. Hence, we have not changed the submission in this area.

We thank you for your patience in this matter and confirm that the revised submission is now able to be publicly released.

Yours sincerely

Roman Domanski
**Executive Director**

Energy Users Association of Australia
ABN 83 814 086 707
Suite 1, Level 2, 19-23 Prospect Street, Box Hill, Victoria, 3128
Phone: (03) 9898 3900 Fax: (03) 9898 749 Email: euaa@euaa.com.au
www.euaa.com.au

# Submission to the Transmission Frameworks Review Issues Paper

4 October 2010

**Acknowledgement & Disclaimer**

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The views expressed in this document are those of the EUAA and do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission.

Suite 1, Level 2
19-23 Prospect Street
Box Hill VICTORIA 3125
Tel: +61 3 9898 3900

Email: euaa@euaa.com.au
Website: www.euaa.com.au

**Table of contents**

# 1. Introduction and summary

This document is the Energy Users Association of Australia's (EUAA) submission to the AEMC's Issues Paper on the Transmission Frameworks Review. This introductory section sets out a few of the main points, and the rest of the submission answers each of the Issues Paper's questions in turn.

The EUAA has over 100 members and represents the interests of many of Australia's major electricity users. Our members are the largest single collection of major energy users, and together they provide much of the income that the Australian Energy Regulator (AER) allows transmission network service providers (TNSPs) to recover.

Our members are generally dissatisfied with the arrangements for transmission network service provision in the National Electricity Market (NEM). As we discussed in further detail in this submission, transmission revenues and regulated asset bases – particularly amongst government-owned network service providers – have risen far faster than energy or demand growth. Our members are therefore concerned to ensure that TNSPs provide an acceptably reliable service at an efficient level of cost. They are also concerned that the current regulatory regime and the implementation of the regime has protected monopoly network service providers from the disciplines that drive efficiency in competitive businesses.

TNSPs often (successfully) argue that transmission is just a small part of the average user's bill. Transmission may be a relatively small part of the total electricity supply chain for small users, but it matters a great deal for big users and generators. It also plays a fundamental role in the market that goes well beyond its direct cost to energy users, for example, affecting the price of energy. At the margin, transmission has a critical impact on market outcomes.

Our members are concerned that renewable energy and emission reduction policies will lead to significant additional transmission network extension. We do not have an accurate picture of how much additional investment is required, and other on-costs – such as investment in gas turbine capacity, or investment in equipment to maintain voltage and system frequency. Whatever this requirement is, it seems very important to ensure that this investment is efficient, considering the likely magnitude of this investment.

Conceptually, the EUAA is not opposed to existing renewable energy or possible future, emission reduction policies, provided that these are focused on the lowest cost options and recognise the impacts on Australia's trade exposed economy. We are wary that these policies will result in much higher costs, and further enlargement of network monopolies. In particular, the 'easy option' is to transfer delivery and development risks associated with the renewables policies on to monopoly network service providers, who then pass the risks and the cost of managing them, to energy consumers. We are already seeing evidence to this in the NEM.

Our members are therefore very keen to ensure that changes that are made to the transmission frameworks ensure that the beneficiaries of renewable energy and emission reduction policies are exposed to their costs. At the very least this means making electricity generators more accountable for the transmission and power system costs they cause. In return, generators should be empowered by defining more precisely their access rights. Concomitant with this is making them pay for transmission access. This will draw them into the debate and decision-making on the appropriate level of spending by, and remuneration of, TNSPs.

We intend to contribute constructively and in detail to this review. The issues in this review are very complex, and it may be tempting for stakeholders to cherry-pick positions and arguments that suit sectional interests. If the review descends to this level, it will become unconstructive. We trust the AEMC will ensure that this does not happen.

The following points describe the underlying principles that guided our thinking in preparing this submission. We suggest that:

- Transmission frameworks should seek to minimise the scope of monopolies – as far as possible solutions delivered by competing businesses should be sought;
- Transmission frameworks should as far as possible empower transmission users – not regulators - to deliver innovative solutions to service and regulatory problems;
- Risks should be borne by those best able to manage them. Only in the rare circumstances that no party or group is better than another in managing those risks, should risks be allocated to the parties best able to bare them;
- Every opportunity should be sought to reduce the scope of regulation; to simplify what remains of it and ensure it is focussed on genuine, powerful incentives rather than bureaucratic compliance.

# 2. Question 1. Minimisation of total system costs

*We understand that the AEMC is asking whether investment and operational decisions across transmission and generation are minimised in total.*

Transmission is a close substitute and complement to generation, but electricity market reform in Australia, as in many other countries, separated them and exposed the latter to competition and the former to regulation. Would generation-transmission monopolies be better than a deregulated market? We cannot be sure. This is not a tractable question and we presume is not seriously on the agenda for this review. Hence, we have not given it further attention.

Since the ACCC and AER has been responsible for regulating transmission network service providers, transmission revenues have grown on average by 8.5% per year, and the value of the regulated asset bases by 8.9%.[1] This is equivalent to growth in regulated revenues of 80%, and the regulated asset bases of 149%. The highest increases in both cases have been by the transmission network service providers in New South Wales, and the lowest in Victoria. The regulated asset base of the TNSPs in NSW have grown approximately four times more than that of the network service provider in Victoria.

However, energy sales over the same period have grown only around 1.6% on average, and have been stagnant in several states (South Australia and Tasmania). Only Queensland has recorded meaningful annual energy sales growth of 2.5%[2].

Neither does annual peak demand growth[3] explain much of the increase. In South Australia, annual peak demand has grown by only 0.5% compounded annually between 1999 to 2009. New South Wales annual peak demand growth is only 1.7% compounded annually, while only Queensland and Victoria have seen any meaningful annual peak demand growth (3.9% and 3.4% compound annual respectively, over this period). [4]

[1] This is based on data in various AER Final Decision documents. It is based on Compound Annual Growth (CAGR) calculations in nominal terms from the first year of the regulatory period established by the ACCC to the last year of the current regulatory period.

[2] This is based on data available from the AER's *State of the Market* Report, 2009, Page 76 and 77. The data in these charts can also be found on the AER's website.

[3] This is defined as the compound annual growth in the simultaneous maximum demand in the period from summer 1998-9 and winter 1999 and the maximum demand in the period summer 2008-9 and winter 2009

[4] Ibid, page 77

These numbers suggest there is a problem – how can revenues and asset bases have grown so much while the services provided (energy conveyed and peak demands satisfied) have grown so little? It is beyond this submission to answer this question definitively. Similar factors that have resulted in extraordinary increases in distributor expenditure (government ownership and the design and implementation of price control regulations) could also explain the large increases in regulated assets and revenues of government-owned TNSPs.[5] The AEMC should examine the role of ownership, regulatory design and regulatory implementation in assessing whether total system costs have been minimised.

[5] See Mountain, B, and Littlechild S.C., 'Comparing Electricity Distribution costs in New South Wales, Great Britain, and Victoria', *Electricity Policy* (2010)

# 3. Question 2: The role of transmission

*We understand that the AEMC is asking whether transmission network service providers are providing the right services and specifically whether the role of transmission in facilitating markets should be defined more clearly.*

Our response focuses on the following aspects

- The specification of reliability obligations;
- Transmission services provided to generators;
- The separation of ownership and planning;
- Arrangements for connection.

**Specification of reliability obligations**

Jurisdictional governments specify the reliability standards that the TNSPs operating in their jurisdiction are required to satisfy. Through this, jurisdictional governments are able to significantly affect the capital expenditure requirements of their TNSPs. We are concerned that the decision that jurisdictional governments make on reliability obligations could be coloured by their desire for financial returns from TNSPs (regulated returns are proportional to the asset base and so encourage Governments that profit from these business to look for ways to expand the asset base). The relative expansion of the Regulatory Asset Base (RAB) of TNSPs in New South Wales compared to that in Victoria strongly suggests this is an issue. The AEMC should examine this further.

For the avoidance of doubt, our reference to this issue should not in any way be construed as unquestioned support for "national consistency" in reliability standards. The on-going debate on different ways to specify and assess reliability standards has been very instructive and we would be very concerned by any move to the lowest common factor, as the price to be paid for so-called consistency.

**Transmission services provided to generators**

Generators in the NEM have non-firm transmission access, i.e. they are not compensated for any lost profit if they are constrained-off the power system, and similarly are not compensated (unless directed) if they are constrained-on to produce more electricity. The absence of constrained-on payments is likely to less significant than compensation for lost profits if constrained-off, since generators most likely to be constrained-on are likely to be at or close to the regional reference node and hence their higher bids are reflected in the Regional Reference Price (RRP).

In reality the firmness of access for some generators may be somewhat greater than implied by this technically correct description of access rights. For example, government-owned generators may be able to influence the investment and operating decisions of government-owned TNSPs, to deliver firmer transmission access.

Even where ownership is not a factor, generators that would otherwise be constrained off the power system are able to limit this possibility by specifying ramp-down rates at the minimum allowable rate of 3MW/minute. This is sufficiently low to minimise the chance of being constrained-off the power system for most short-lived high-price events.

In other words, generator access in many cases may be firmer than it appears on a narrow reading of generators' rights and TNSPs' obligations.

Should generators obtain firmer access than they do now? This is a very difficult question. Firmer access may enhance the liquidity of contract markets, could reduce incentives for vertical integration and may stimulate new generation entry. These would all be positive developments for the competitiveness of the electricity market, and hence outcomes our members would welcome. Against this, however, firmer access also entails the transfer of dispatch risk from generators to TNSPs (and hence directly to users). We would be very concerned about this, not least because it contravenes one of the main objectives that we suggest this review should pursue.

More specifically, we are concerned that TNSPs are unlikely to manage this risk effectively or efficiently. The lack of progress in the development of constraint management incentives (we discuss this in more detail later) gives us little confidence that TNSPs could be incentivised to manage this risk effectively.

An alternative to providing firm transmission access (with all risk of congestion passed to TNSPs) is to define property rights in transmission access which generators can then acquire to achieve whatever level of firm access they desire. This is a particularly complex area and has been studied at length in academic and practitioner settings in Australia and elsewhere, particularly over the period from the mid 1990s to around 2003. We would urge caution on the AEMC in embarking on this debate. Our best understanding is that little progress has so far been made anywhere in defining tradable property rights in transmission, and we believe that the transmission frameworks review should consider this. It is possible to consume considerable resources and energy debating this, and the AEMC should consider whether effort in this review is not better directed at problems that are more amenable to resolution in developing an improved transmission framework for the NEM.

**The separation of ownership and planning**

The predominant model in the NEM is for TNSPs to plan, own and operate the transmission assets within its area of jurisdiction. Our view of the various transmission plans produced by AEMO is that these are not much more than high level indicative statements of long term transmission expansion visions. The plans have no executive authority, and AEMO is in no position to direct or instruct TNSPs on how they should develop the transmission networks in their areas. The arrangements in Victoria are an exception to this, with AEMO responsible for planning the network (and tendering for major augmentations) and SP Ausnet as the dominant asset owner. The outcomes in Victoria relative to the outcomes delivered by TNSPs elsewhere in the NEM are favourable. As noted earlier, the regulated value of TNSP assets in Victoria has grown 40% while those in New South Wales has grown 160%, since the TNSPs in each state have been regulated by the ACCC and then the AER. This is despite significantly higher demand growth over the last decade in Victoria compared to NSW.

The Victorian approach of separating planning and major asset procurement from asset ownership is innovative and should be assessed in detail by this review. We suggest that a thorough comparative analysis of transmission outcomes in Victoria relative to those elsewhere in the NEM would be very valuable for this review. Lessons should be drawn out and should provide the basis for suggestions on improvements to transmission frameworks in the NEM.

**Arrangements for transmission connection**

We are aware of numerous complaints by prospective generators and larger energy users on the arrangements for transmission connection. It seems these complaints focus either on:

- inconsistent treatment (by TNSPs in their own area or amongst TNSPs in different parts of the NEM); or
- the usual complaints associated with dealing with monopoly service providers (delay, lack of co-operation, cost-shifting, gold-plating at customer's expense, intransigence).

We have not yet compiled a comprehensive description of the experience of energy users in this area, but intend to do so. Nevertheless, even the known experience of prospective connecting generators and larger energy users gives us cause for concern: defective connection arrangements are a barrier to generation entry and plant expansion for example. This reduces competition and consumers are likely to be the poorer for it, as well as investement.

On the basis of the complaints to hand, it seems that this area would benefit from detailed investigation by the AEMC. It would be premature to specify solutions, but consistent with our earlier stated objectives for this review, we would like to suggest the following:

- Great care should be taken before pursuing "national consistency" for its own sake. We note that the negotiation of national consistency can result in the wide-spread adoption of the least efficient solution; and
- As far as possible, the AEMC should be looking for solutions that limit the role of TNSPs in transmission connection. We strongly urge the AEMC to seek solutions that devolve as much as possible to service providers that compete in real markets. Where this is not possible, we urge the AEMC to consider how transmission users might be directly involved in the regulation of connection arrangements.

# 4. Question 3: Transmission planning

*We understand that the AEMC is asking whether the existing arrangements provide information to TNSPs on where and when to invest, or whether additional price signals might be beneficial.*

We see no particular information problem – between the TNSPs and AEMO it should be possible to acquire ample information on the intentions of prospective new entrants. However, we do see a serious incentive problem:

- For TNSPs to prefer transmission solutions relative to generation or demand solutions (we expand on this in our answer to subsequent questions);
- For TNSPs to gold-plate (we expand on this in our answer to subsequent questions); and
- For TNSPs to act in their own interests in planning their networks, rather than necessarily in the national (NEM-wide) interest (we expand on this in the rest of our answer to this question).

Transmission planning arrangements have been the focus of much discussion in the NEM since its beginning. The Parer Review ("towards a truly national energy market") and then the ERIG Review both had a strong focus on planning arrangements, and recommended greater centralisation.

We agree with the underlying issue that geographically distinct TNSPs are more likely to favour their own best interests rather than the NEM as a whole. However, neither the Parer nor ERIG reviews ultimately seemed to have made much progress: after all the debate, transmission planning decisions (other than in Victoria) are still the preserve of regional network service providers. As we suggested earlier, we are sceptical that AEMO's national studies have had or will have any meaningful impact on TNSP's investment plans.

Is this a major problem? Looking back, we are not convinced that it is. With the exception of Tasmania and to a lesser extent South Australia, Australia's abundant coal and gas resources has meant that it has been possible to construct the main regional generation complexes close to the demand centres (Latrobe Valley – Melbourne, Hunter Valley – Sydney, SE Queensland - Brisbane). Marginal production costs in different regions have not differed significantly, and hence relatively limited interconnector capacity has been built. This outcome ultimately seems reasonable. While greater central co-ordination may have resulted in different network patterns, it seems hard to conclude that the outcome for the main backbone systems would have been radically different.

However, looking forward we think that inadequate signalling of the localised value of transmission access may well be a significant problem in transmission planning. Renewable energy and emission reduction policies are likely to favour large-scale wind farms (with the best resources available in South Australia and Victoria) and gas generation (with the best resource in the off-shore Gippsland basin, the Surat and Bowen basins and lesser resources in the Cooper and Otway basins). Electricity transmission development will be fungible with gas pipeline development and will impact the location of wind farm developments.

We do not have a strong sense of the size of the transmission investment task, and how power flows around the NEM might change over time in response to renewables and emission reduction policies, but we think this is something that the AEMC should examine it in detail.

In the context of possibly significant changes in power flows, it seems very important that the best possible signals are given to new generation entrants (and incumbents) on where to develop new plant (or expand/close existing plant). For this reason, we strongly endorse the recommendations of the AEMC's climate change review to introduce use of system charges for generators. In line with our desire for risks to be allocated to those best able to bear them, we hope that the AEMC will promote use of system charges that reflect as strongly as possible the cost differences attributable to geography, time of use and transmission voltage.

# 5. Question 4: RIT-T and investment to reduce congestion

*We understand that the AEMC is asking whether the RIT-T (and other mechanisms) will provide for efficient and timely investment in the shared transmission network. The AEMC appears to be particularly concerned about the level of future transmission congestion.*

We have two perspectives in answer to this question, itemised below and discussed thereafter:

- We think the RIT-T will fall far short of the hopes expected of it; and
- It is not clear how changes to power flows attributable to RET and emission reduction policies will affect transmission congestion.

The RIT-T is now the fourth iteration of the regulatory test since it was first developed around a decade ago. Very considerable effort has been invested in specifying the test over the last decade. Ultimately, however, we are sceptical about the value of this. There will always be considerable uncertainty about the costs and benefits of transmission investment. This is the nature of the problem. Attempting to solve the problem through ever more precise definition of costs and benefit is, we suggest, mis-placed effort: an ever more detailed or precisely specified test does not make an uncertain cost or benefit any more certain. For this reason, we have little faith in the RIT-T and do not think it provides the basis for an assessment of whether network service providers are under or over spending on networks.

We do not have a simple or easy answer to the problem of determining the efficient quantum of transmission investment. However, we suggest far greater effort be placed on finding ways to involve transmission users in regulatory oversight, and where this is not possible then in the design of powerful efficiency incentives, rather than in the implementation of ineffective and mis-leading compliance approaches such as the RIT-T.

On the second issue – transmission congestion – the AER's Total Cost of Constraints (TCC) measure has ranged between $36m per year and $189m per year and averaged $87m over the six years that data has been produced.[6] This is around 1% of the average value of electricity traded in the NEM. Compared to aggregate annual TNSP revenues in 2010, the average total costs of costs is around 3%.

[6] AER, State of the Energy Market, Page 143.

These data suggest that, *prima facie*, transmission congestion is not a big issue. However, there are other ways of understanding the problem of constraints. Generators do not have firm access to transmission in the NEM. This is mainly an issue for generators that are constrained off the system, in order to relieve transmission congestion. Constraints are typically associated with high prices at the Regional Reference Nodes, and so generators will seek to maximise production to take advantage of these higher prices. To fight against the prospect of being constrained off they will bid down to the lower price limit (-$1000/MWh), and failing that, limit their ramp-down rates to the minimum allowable under the Rules (3 MW/minute). These actions exacerbate, not relieve, the constraint. All things being equal, this prolongs constraints and makes them more expensive to relieve. The AER illustrated this clearly in their explanation of recent high priced events in NSW on 10 August 2010. ([www.aer.gov.au/content/index.phtml/itemId/714860](www.aer.gov.au/content/index.phtml/itemId/714860)).

The way that we understand this is that although generators do not have firm transmission access – and thus face the risk of not being dispatched when the network constrains – consumers appear to be worse off as a result of the way that generators try to manage this risk.

This outcome can be compared to the arrangement in Britain where generators have financially firm transmission access – and are compensated for the lost profit if they not dispatched as a result of transmission constraints. From a consumer perspective, this has the unwelcome feature that consumers are bearing the cost of compensating generators for network congestion. But the positive aspect of this is that generators in Britain have a much weaker incentive to exacerbate transmission constraints in an effort to continue to be dispatched: if they are being compensated for the lost profit as a result of the constraint they will have no particular incentive to continue to be dispatched, and hence their actions will not exacerbate network constraints.

Following this observation to its conclusion, it is not clear that consumers (or generators) are better off in the NEM arrangement, compared to what might apply under arrangements where firm access was achieved, and congestion managed appropriately. This complex area merits further detailed and careful analysis.

Finally, we have some specific comments on the AER's recently adopted constraint management incentive. The rest of this section explains our views on this.

The AER has recently introduced constraint incentives on TransGrid and some other network service providers. As we understand it, there is a sliding scale with a cap of 2,857 five-minute trading intervals where marginal values of transmission constraints exceed $10/MWh, so that TransGrid is able to earn up to a maximum of 2% higher allowed revenue per year (if there are no trading intervals where the marginal value exceeds $10/MWh).

We are a little doubtful that this incentive scheme will be effective. For example, on 10 August 2010, the spot price of electricity in NSW reached $12,500/MWh for around 40 minutes. This was attributable to constraints between Mt Piper and Wallerawang caused by a planned outage of a transmission line in combination with other generator outages. The wholesale value of electricity traded in NSW over this period was around $100 million, when it would normally have been around $300,000 had there been no such constraint over this time period. Under the AER's constraint incentive, TransGrid suffered no loss as a result of the constraint. The ten 5-minute trading intervals where the marginal value of constraints exceeded $10/MWh are just a tiny fraction of the 2,857 5-minute trading intervals in its incentive scheme. Under the AER's constraint incentive TransGrid has suffered no loss as a result of the constraint, and neither would it have gained in any meaningful way if it had avoided the constraint, by changing its outage schedules or taking other actions to relieve constraints. It seems from this that it is reasonable to conclude that the constraint incentive is unlikely to be successful.

Looking ahead, it is not clear to us how transmission congestion will change in future. If the RET and emission reduction policies result in significant wind and gas generation development, this is likely to result in significant coal plant closure. In principle, we would expect possibly significant changes in power flows (wind farms are most likely to want to locate in high wind resource areas in Victoria and South Australia) while gas generators (at least high capacity factor plant) may be more likely closer to the main pipelines or the primary gas resources, not necessarily in the Latrobe or Hunter Valley where coal generation is predominantly found.

However, locational decisions will be affected by price signals (on gas pipelines and electricity networks). For the foreseeable future, they are also very likely to be affected by the expectation of future constraints – generators can be expected to avoid locating in parts of the network where they are likely to be constrained off, or where network investment will be needed to relieve possible future constraints. In this way, the absence of compensation for constraints may have a significant impact on generator siting, and hence on the level of constraints.

We recognise, however, that this may be a very incomplete solution to the problem: if there is an investment strike or delay because transmission access is not available, energy users may be worse off through REC and possible future emission prices that will be higher than they otherwise would be.

To inform the decision on the appropriate action here, it would seem to be very helpful to understand how generation location may vary under different transmission access arrangements, and then to attempt to calculate the difference in transmission cost (and market prices) under those arrangements. This will help to inform the decision on what changes might be needed. By identifying the beneficiaries of those changes, it will be easier to decide the allocation of the costs of additional network augmentation.

# 6. Question 5: Economic regulation of TNSPs

*We understand the AEMC is asking whether the revenue control arrangements specified in the National Electricity Law and the National Electricity Rules is leading to appropriate investment decisions and efficient service delivery.*

It should be very clear from our submission to this point, that the EUAA's members are unhappy with the design and implementation of TNSP revenue controls. As described earlier, the growth of revenues and regulated asset bases seems far out of proportion to the modest growth in energy transported or peak demand satisfied. The main criticisms we have, are summarised below. The EUAA has worked extensively on these issues in the context of AER revenue and price control reviews, and we would be happy to discuss our views on these issues in further detail with the AEMC:

- Failure to account for Government ownership
- The 'propose-respond' model favours network service providers
- The AER has failed to benchmark
- Excessive rates of return have been allowed
- The appeal mechanism is not a level playing field and encourages 'cherry-picking'

**Failure to account for government ownership**

Under the current arrangements it is assumed that all TNSPs are privately-owned, and their allowed rates of return are calculated on this basis. However, the TNSPs in NSW, QLD and TAS are government-owned. The jurisdictional governments receive dividends and income taxes on the profis from these businesses. The effect of this financial interest (as well as various other non-pecuniary benefits that government owners derive) is resolutely ignored in the design and implementation of the regulatory arrangements. This is absolutely at consumer's expense and we strongly oppose it.

**The propose-respond model favours network service providers**

The EUAA's members have been very disappointed with the outcome of the AEMC's Chapter 6 review of the National Electricity Rules, and the resultant adoption of the 'propose-respond' model. This model places the AER at a disadvantage to the TNSPs and weakens the AER's ability to specify the content and format of regulatory expenditure submissions. The arrangement works from the presumption of "innocent until proven guilty". Quite obviously this is inappropriate considering the incentive TNSPs have to overstate their expenditure requirements.

**The AER has failed to benchmark**

The AER has clear obligations in the National Electricity Rules to benchmark the capex and opex proposals of TNSPs. So far the AER has consistently failed to meet this obligation. We suggest that this has had a significant impact on the AER's ability to assess the efficiency of TNSP expenditure proposals.

**Excessive rates of return have been allowed**

We contend that the AER has allowed TNSPs to earn excessively high rates of return, as a result mainly of excessively high estimates of the debt risk premium. We have provided detailed submissions on to this to the AER in the context of its current distribution price control review and would be happy to share our work with the AEMC.

**The appeal mechanism is not a level playing field and encourages cherry-picking**

TNSPs and other affected parties are able to appeal the AER's regulatory decisions subject to various conditions set out in the National Electricity Law. Almost all the AER's revenue and price control decisions have been appealed. We contend that this arrangement has worked badly. TNSPs have an asymmetric advantage in funding appeals. The cost of the appeal is absorbed by users – unless the AER disallows it in assessing future opex allowance (something the AER has not yet done). By contrast, users face the problem of free-riding which means that even appeals that are likely to benefit all users are difficult to fund. Furthermore, the appeal mechanism encourages cherry-picking. At worst if an applicant feels that a decision by the Australian Competition Tribunal is likely to go against it, it is able to withdraw the appeal and the AER's decision would stand. Network service providers have been able to achieve extraordinary revenue increases as a result of appeals. For example, a recent appeal by distributors in NSW resulted in increases in the allowed revenue of around $2bn over five years. It is particularly concerning that the ACT was not aware of the impact of its decision on allowed revenues before it reached its decision.

# 7. Question 6: Network charging for generation and load

Our response to this question is covered in our response to Question 4. To reiterate the main point, we strongly support the AEMC's CCR recommendations on use of system charges for generators, inter-regional transmission charges, and use of system charges that are as cost-reflective as reasonably possible. We recognise that there may be some transitional issues for existing generators that have not yet been exposed to these charges. Some form of transition may be necessary if the impact is calculated to be significant.

# 8. Question 7: Nature of access

*We understand that the AEMC is asking whether arrangements should be developed to allow generators and load to obtain firmer transmission access.*

Our response to this question has been dealt with in part in our response to Question 2 (under the paragraphs headed "transmission services to generators"). In principle we support differentiated payments for differentiated levels of transmission access. The difficulty is how this is to be achieved.

We are wary that TNSPs are able to negotiate different levels of firm access with different consumers. Since TNSPs are regulated entities, this arrangement may result in cost-shifting from generators to consumers (since TNSPs are likely to be able to pass on to consumers any risks they may face in meeting negotiated firm access obligations to generators). We are not convinced that the current regulatory arrangements are capable of ensuring that such cost-shifting does not happen.

We would be in favour of some form of tradable property right that, after primary allocation, would be tradable in secondary markets. This could mean that network users could trade amongst themselves to obtain whatever level of firmness they desired. However, as we noted earlier, many fine minds have worked on this before, with little apparent progress. As we concluded earlier, other challenges seem to be easier to resolve.

# 9. Question 8: Connections

*We understand that the AEMC is asking whether connection arrangements are adequate in general and, in particular, whether it would be appropriate to review the SENE proposals?*

We have provided some general perspectives on existing connection arrangements in our answer to Question 2. The rest of this answer sets out our views on the SENE proposals, some of which we provided in response to the AEMC's CCR consultations.

Our main concern on the SENE is proposals, is that we think that a case has not been made for the proposed arrangement. The essence of the AEMC's CCR arguments are that wind development were likely to cluster in South Australia and in Victoria where wind resources were the most advantageous, and that there is a market failure in transmission connection that requires the development of additional arrangements.

While we do not dispute the evidence that wind resources appear the most advantageous in South Australia and Victoria, we think there are several unresolved questions on how to connect such generation at the lowest cost, and who should bear that cost. For example:

- Will connecting wind generators in regional clusters not be able to agree amongst themselves how to connect to the network, and how costs should be shared? If not, why not?
- Will subsidised connection or network augmentation result in higher wind generator profitability or will this apparent cost advantage be competed away?
- How can connection and shared network assets be developed in a way that delivers effective competition in network development, if not in network operation?

We are concerned that the AEMC may not yet have given these questions sufficient consideration. The existing SENE proposal shifts the risk of cost overruns and stranded assets onto energy users. The AEMC has suggested that these risks can be managed through various long-winded compliance procedures to be undertaken by AEMO and the AER. We have little confidence that this will provide any meaningful protection for energy users. The track record, as we have set out earlier, gives us cause to doubt the AER's ability to restrain government-owned network monopolies.

We suggest that a better approach would be to develop regulatory arrangements that empower transmission users to be exposed to the costs of connection and hence to have a meaningful interest in what these costs are.

As we have noted several times earlier, a form of tradable property right in transmission may be a step too far. However, there should be other ways to empower transmission users. Possible ideas that could be explored further (on their own and in combination) include:

- Empowering AEMO to tender for the development and ownership of shared connection capacity, rather than simply handing a monopoly to existing TNSPs. This is the approach that has been taken to transmission provision in Victoria generally and in Britain for off-shore transmission networks and in Texas for Renewable Energy Zones, apparently to good effect in all three cases;
- Encouraging the formation of network investment consortiums amongst wind farms developers. These consortia could develop and own network capacity with rules for third party access to shared network infrastructure, but price regulation under those rules by transmission users with an option for independent dispute arbitration (this is a variation on the "light-handed" regulation option for gas pipeline access); and
- Ensuring a definition of transmission connection that minimises the scope of regulated monopoly.

Of course, consideration along these lines is far more challenging than simply extending the monopoly of TNSPs, and the oversight of the AER, as the AEMC has proposed with the SENE arrangement. We are keen to work with the AEMC to explore arrangements that minimise the scope of regulation and maximise the involvement of transmission users (both end users and generators) in the regulation of any additional connection assets and shared network that is developed to facilitate renewables entry.

# 10. Question 9. Network operation

*We understand that the AEMC is asking whether incentives on TNSPs to maximise network capacity and to minimise the cost of this capacity, are working.*

Our response to the second part (cost minimisation) is set out in our response to Question 5. In summary, we do not think the current arrangements are working well, for the reasons we set out in our answer to that question.

Our response to the first part (capacity maximisation) is set out in our answer to Question 4. In summary, we do not think the current constraint incentive is likely to be successful. It is useful to compare the experience in Britain and Australia in this area, to understand more fully why so little progress appears to have been made in this area in Australia.

In Britain, after the cost of constraints rose in 1993 and 1994, a forum of transmission users developed a voluntary incentive scheme on the National Grid Company to reduce the cost of transmission. This worked remarkably well and was then passed on to the Office of the Electricity Regulator (Offer) to develop further. Since 2007, the National Grid Company has been subject to regulatory incentives to minimise the cost of constraints.

By contrast in Australia, the ACCC first met with NEMMCO in 2003 to consider how to establish a measure of the cost of constraints. Six years after this, the first incentive scheme has been developed, and it is not at all clear that this scheme is likely to have any positive effect in motivating TNSPs to reduce constraints. This represents torturously slow progress.

Perhaps part of the reason for the comparative success in Britain but failure in Australia in this area, is different attitudes to regulatory incentives by network service providers and regulators in both countries (i.e. the British network service providers being more positively disposed to incentives than the government-owned Australian network providers).

A second explanation is that in Australia network services are performed by numerous network service providers and there is a separation of network operation (by TNSPs) and power system operation (by AEMO). Since both network service providers and network operators can affect the incidence and level of constraints, this diffuse responsibility makes it more difficult to create incentives to manage constraints. For this reason, we think that significant improvement on the current arrangements may be difficult.

# 11. Question 10: Congestion management

Our answer to this question is set out in the second part of our answer to question 9.