Hydro Tasmania

the renewable energy business

25 February 2009

Dr John Tamblyn,

Chairman, Australian Energy Market Commission,

PO Box A2449,

Sydney South NSW 1235

By email: submissions@aemc.gov.au

Dear Dr Tamblyn,

Re : **Review of Energy Market Frameworks in light of Climate Change Policies, 1st Interim Report**

Hydro Tasmania would like to thank the AEMC for the invitation to comment on the material presented in the 1st Interim Report published as an outcome of the Review of Energy Market Frameworks in light of Climate Change Policies, (the Review). Hydro Tasmania is also a party to a submission by the National Generators' Forum.

We understand that the Commission has endeavoured to assess the resilience of the existing rules and regulations governing behaviour in energy markets, given the expected changes in market behaviour arising from the CPRS and expanded RET.

The focus of this Hydro Tasmania submission is on:

1. the AEMC's selection of issues for consideration;
2. the determination of the materiality of each factor in terms of the impacts of CPRS/RET; and
3. a brief discussion of the options for change.

In this submission we discuss the issues in the order in which they were treated in the 1st Interim Report. Unless specifically stated otherwise, our comments are restricted to potential framework weaknesses in the NEM, rather than the WEM or NT arrangements.

Broadly, we believe that the Commission has identified correctly the two critical areas, where the Market Frameworks are likely to be stressed by Climate change policies. We support focussing the Review on the potential impacts of:

a) a large increase in new generation, particularly wind generation, if as expected it is located at remote parts of the transmission network; and

b) potential financial stress arising from carbon pricing

We agree with the Commission's view that the 'energy-only' market design of the NEM appears to be working to provide timely investment and that there is no evidence to suggest that appropriate investment will not occur in the future. For this reason, we do not support any investigation of a potential changes in this area.

In recent years, Hydro Tasmania has given considerable thought to the issues around integration of wind generation in the NEM. We agree that some changes to the NEM treatment of rotational plant inertia may be required, and caution against excluding this issue from any discussion on wind integration in the Review's Final Report. Inertia is particularly critical in the Tasmanian context.

Whilst we believe that local planning and environmental approvals processes are outside the scope of the Review, we believe that unless these are streamlined, it will be difficult to develop the quantity of new renewable generation and associated transmission envisaged by the Climate Change policies.

We strongly believe that the following transmission issues are material, and must be addressed by the Review:

- optimisation of multiple connection applications in a cluster,
- the need for strengthening of the shared transmission network, above that which may be supported by the Regulatory Investment Test, and
- the impact of the chosen cost recovery method on investment efficiency and new renewable technology choice and location

Some proposals to address these issues are included in our submission. We are interested in sharing further ideas and participating in the proposed Forum in April 2009.

If you require any further information, please contact me on (03) 6230 5775.

Yours sincerely,

D. Bowker

David Bowker

Manager Regulatory Affairs

Hydro Tasmania

Hydro Tasmania's Submission on 1st Interim Report

"Review of Energy Market Frameworks in light of Climate Change Policies"

Overview

Broadly, we believe that the Commission has correctly identified the critical areas, where the Market Frameworks are likely to be stressed by a large increase in new generation, particularly wind generation, if as expected it is located at remote parts of the transmission network.

We note also the Commission's concerns in relation to potential financial stress arising from carbon pricing and agree that a moderate response may be required to manage any supply security implications.

We understand that the Commission is uncertain about the materiality of the problems of:

1. Optimisation of multiple connection applications in a cluster;
2. Investment drivers for new transmission infrastructure to economically manage congestion; and
3. The cost recovery of this investment, particularly in relation to inter-regional augmentations.

We strongly believe that these transmission issues are material, and must be addressed by the Review:

Market Investment

First of all, we believe that the Commission's conclusions in relation to market investment and the timely provision of new generation capacity are broadly correct. Uneconomic, public, supply-side over-investment is to be avoided, as not in the long-term interest of customers, even if it creates low energy prices in the short-term.

Investment in the NEM has occurred at a steady rate [ref NEMMCO submission to the Issues Paper] and whilst this has not created the large supply side buffers which existed pre-NEM, there is no evidence that investment will not occur in a timely manner in future, even with CPRS/RET.

However, we note that the issue of local planning and environmental approvals processes has not been considered in the 1st Interim Report. We agree that this is outside the scope of the Review, but we believe that unless these are approvals processes are streamlined, it will be difficult to develop the quantity of new renewable generation and associated transmission envisaged by the Climate Change policies.

Single-Region Reserve Shortfall arising from Thermal Failure

We note the Commission's concerns about an actual or anticipated large reserve shortfall in a region. We would caution against using the 2008 SOO forecasts as a basis for precipitate regulatory intervention.

Consequently, we believe that changes in this area should be moderate. In any event, they should not extend to pre-emptive public investment in reserve generation, which may hide the necessary signals for a market response to risk.

Retail Stability and RoLR

We agree that the area of retail stability is of concern, and in particular consider that price pass through arrangements for carbon costs are inevitable, in regions where price caps still exist. Any increase in prudential costs will exacerbate the situation.

We agree that the "Retailer of Last Resort" provisions may need to be reviewed but caution that there is the risk of moral hazard; free risk management for imprudent retailers should not be part of regulatory policy.

Wind Integration

We note the Commission's conclusions in relation to the impact of recent changes to the NEMMCO dispatch systems, forecasting and technical standards; all of which enhance the ability of the existing market to integrate wind generation successfully. We agree that the market frameworks in this area are relatively robust.

We agree that there are indeed potential shortcomings in the way in which inertia is treated, (or rather assumed to be freely available) in the current market and recognise that NEMMCO is monitoring the issue. We will continue to participate in discussions with NEMMCO in relation to enhancing the market arrangement to facilitate the integration of wind generation, particularly in Tasmania where system inertia is relatively low, compared with the much larger mainland system. Whilst we accept that this is deemed to be outside the scope of the present Review, we urge the Commission not to lose sight of this issue completely, since any potential solutions may well require supportive Rule changes, (as well as changes to NEMMCO procedures and specifications).

Transmission Issues

We are somewhat puzzled that the Commission considers the transmission issues to arise solely from RET policy, rather than from CPRS. The consequence of a CPRS policy is likely to be a significant increase in gas and new renewables generation, particularly wind. It is true that the relative share of gas generation may well be higher in the absence of a RET policy, however the multiple connection optimisation problem, the changes to inter-regional flow and need for generation-driven transmission augmentation[1] may still occur, eg at a new gas/geothermal field.

It is difficult therefore for us to see the purpose of the clear separation in the Executive Summary of the 1st Interim report between CPRS and RET effects; surely significant modelling is required to determine the materiality of the impact of either/both of these on transmission. Even then, the outcome will be very dependent on input assumptions.

Putting this rather philosophical issue aside, the potential market framework weakness in relation to transmission, which were raised in the 1st Issues Paper were:

1. Optimisation of multiple connection enquiries at a generation cluster; and
2. Management of network investment and congestion.

[1] That is, not supported by the Regulatory Investment Test, but driven by the new generators' need to gain an efficient level of access to the RRN – balancing the management of both price and volume risk to support the trading position.

We note that ROAM Consulting in its 17 December 2008 report, "Market Impacts of CPRS and RET" prepared for the Commission, expressed the view (on pg 61) that:

> "The materiality of potential inefficiencies from new entrants and the 'coordination problem' surrounding connection applications is considered minor."

And later on the same page

> "Given that intra-regional and inter-regional transmission congestion will provide a material risk to wind developments in particular, the materiality of inefficient local connection assets is considered low against the requirement to manage the growth of the transmission network necessary to maximise the capacity for the RET to achieve maximum renewable energy uptake."

This view is not reflected in the AEMC's 1st Interim Report, which proposes several options to solve the multiple connection optimisation problem but, in our view, does not adequately address the equally severe problem of how to plan, develop and recover costs in relation to shared network investment.

We consider that the way in which cost recovery is managed is critical in determining the manner in which renewables are rolled out, affecting both location and technology choice. For example, if consequent shared network augmentation costs are recovered from the market as a whole, or from CPRS revenue, then this will tend to drive remote wind farms in preference to:

- gas, (where transmission costs are internalised), or
- lower capacity factor wind farms, located closer to transmission, or
- apparently more expensive renewables, eg solar thermal or hot rocks, closer to load.

Some work on this has been done by ROAM Consulting, acting for the National generators' forum, and it is perhaps based on this modelling that ROAM has developed their view in relation to relative materiality. The AEMC may not have access to the NGF evidence.

Given that we don't have an accepted definition of a materiality threshold; it is not surprising that different parties assign different weights to several aspects of the transmission issues. Nor is it easy to see how absolutely hard evidence can be forthcoming for future congestion, given that it is the uncertainty of congestion which is the major risk to trading positions[2]. In fact if congestion at any level were certain, it would be easier for Generators to construct an appropriate contract portfolio, which could be potentially backed by physical dispatch. The dispatch risk (both price and volume) acts as an inhibitor to contract market participation.

Optimisation of multiple connection enquiries at a generation cluster

We note the interesting AEMC suggestion of a "Hub and Spoke" model of transmission development in relation to multiple connection points in a cluster. In our view, Option 2 is the most promising. For the reasons given below, it is considered that the other three options are inferior to (or in the case of Option 3, no better than) Option 2.

The AEMC's Option 1, (the open season approach) has the disadvantage that it precludes the possibility of late connection applications, retains the bilateral approach and

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[2] For example, interaction of constraints relating to Robertstown transformer outage and simultaneous planned outage of Wagga-Yanco circuit on a hot day; far apart but interacting through impact on Murraylink.

consequently is faced with the same confidentiality issues as the current Chapter 5 process.

Option 4 is the same as Option 2, but hub development costs are recovered from customers in each TNSPs area. This fails on two counts, firstly it exacerbates the inter-regional TUOS recovery problem and secondly it fails to provide the efficient locational price signals which are considered as a desirable feature.

Option 3 suggests that the economic test would be assessed by the National Transmission Planner, rather than the local TNSP. In principle, the application of a well-defined test by either body should result in the same outcome. This issue is therefore considered peripheral for the purposes of the present discussion, so that Options 2 and 3 are considered identical.

Consequently, we would support further development of Option 2, leading to a variant which addresses the shortcomings of the present Clause 5.4A arrangements. Some possible areas of development are discussed below.

Management of network investment and congestion

Firstly, a substantial investment in new or augmented shared transmission will be funded by Customers through the Regulatory Investment Test, RIT. The TNSP has the incentives and is able to build this required augmentation within the present Market Frameworks. The only possible point of failure is a resource scarcity, which might arise if the rate of development were very high. Where the requirement is for inter-regional augmentation, we support need for inter-regional TUOS arrangements to be reviewed/strengthened. It is clearly inequitable for Customers in a generation-rich region to pay for transmission which is justified on the basis of providing supply reliability in an adjacent NEM region.

Assuming that the RIT works as intended, this discussion focuses therefore on the scenario where a new generator or group of Generators in a "cluster" require:

1. Individual radial connection assets, ("spokes"),
2. New dedicated network assets to form a transmission "hub",
3. Augmentation of the intra-regional shared network to limit congestion to an economically efficient level, and
4. Augmentation of the inter-regional connection to access appropriate load volume, (and pricing),

beyond the level which is supported by the RIT.

We observe that not all "hubs" are necessarily "virgin". That is, it is conceivable that it is efficient to create a new "hub" by augmenting or extending an existing shared transmission network in a way which is not supported by the RIT. In such a case, it would be inequitable and inefficient[3] to charge these "hub" costs to Customers, (particularly if allocated only to Customers in the local NEM region).

As mentioned earlier, the way in which the cost of this investment is recovered will impact on the decision that each generation proponent makes, ie if any of 1-4 above are paid for by Customers, then it will inefficiently bias developers towards certain types of investment. In this context, we do not see that the cost recovery of 3 & 4 as being different from 1 & 2 in terms of dynamic efficiency outcomes.

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[3] That is, not supporting dynamic efficiency of new investment, by externalising part of the associated investment decision and distorting the market choices in relation to transmission/generation investment.

To the extent that this cost is recovered from proponent Generators, then it:

- will not impact on TUOS, and therefore not on inter-regional TUOS, and
- will need to result in some value accrued to the paying Generators.

At present, Generators do not pay for transmission and have no firm access rights; only a non-firm access to the RRN price for whatever volume they are able to get dispatched, by whatever means possible. They are of course, still exposed to a dispatch volume risk, and this leads to the "race to the bottom", with perhaps some reluctance to enter the contract market. A weakness of the current Market Frameworks is that an existing Generator, which wishes to improve its access by investing in the transmission network, cannot do so in a commercially viable way. Clause 5.4A does not work in practice, because there is little incentive for bilateral negotiation[4], no possibility for multi-lateral discussions and no mechanism to deal with any impact in the dispatch/settlement timeframes.

What we are suggesting is that existing Generators retain the current arrangements, ie no liability for transmission TUOS charges and no financial rights, other than to get access to the RRP for a non-firm proportional share of existing transfer capacity.

Hydro Tasmania has given considerable thought to the issues around integration of wind generation in the NEM, the need for strengthening of the shared transmission network above that which may be supported by the Regulatory Investment Test and the impact of the chosen cost recovery method on investment efficiency and new renewable technology choice and location. We are willing to share further ideas and to participate in the proposed Forum in April 2009.

We support a new process which includes:

- integrated strategic network development across the NEM to achieve the renewable goal at least cost, – This includes an enhanced National Transmission Planner;
- a national, rather than solely regional, perspective, so that competing projects are assessed together, eg any proposal to strengthen the SA-VIC interconnector to support SA wind, should be considered alongside possible improvements to the TAS-VIC interconnection or NSW-QLD;
- some form of internalisation of transmission costs, to preserve economic efficiency and avoid picking renewable technology winners. That is, If development of the shared transmission network is required to support specific new renewable generation, then this should be reflected in higher costs for those projects; and
- a level of MRET penalty or carbon price which reflects the marginal cost of the required[5] volume of renewable technology, (including project-related, shared transmission costs).

What we propose for consideration is a process where an enhanced National Transmission Planner in co-ordination with the relevant TNSPs:

- evaluates competing large scale new wind developments[6];

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[4] It is not even certain that Clause 5.4A applies to incumbent Generators, since the references in Chapter 5 are to 'Connection Applicant' and the problem referred to here is one of an existing Generator seeking better financial access arrangements, as a response to an emerging constraint.

[5] Required by Climate Change policy, rather than the Market objective.

[6] That is, broad planning options for which priority ranking may need to be assigned and which could include say 2000MW of wind in each of SA, VIC, NSW and TAS, each split into say five clusters of 400MW. The ultimate development choice would be with the Market.

- plans the required transmission upgrades;
- completes the environmental and development approvals;
- auctions the shared network access development rights to recover costs, (with a risk premium); and
- tenders for the transmission projects, once sufficient generation development is committed, (cf the AEMC's 50% NERG hurdle, pg 40 of 1st Interim Report).

Some of these functions may in fact be better managed by the local TNSP. This is certainly true for the radial connection assets, the "spokes". The responsibilities and coordination needs to be agreed between the parties. However what is required is a greater degree of coordination than has occurred previously. This is likely given the emergence of the NTP.

The way in which dispatch and settlement aspects of this could be managed has been described in Hydro Tasmania's submission to the AEMC's previous Congestion Management Review[7]. Whilst at the time this was considered in advance of what the Market required, we believe that the time has come to consider it, (or something similar) in terms of the likely materiality of congestion in the face of CPRS and RET.

End of Hydro Tasmania's Submission

[7] See Attachment 2 at http://www.aemc.gov.au/pdfs/reviews/Congestion%20Management%20Review/Draft%20Report/submissions/004Hydro%20Tasmania%20Submission%20-%203%20December%202007.pdf