Hydro Tasmania
The power of natural thinking

29 September 2010

Mr John Pierce

Chairman,

Australian Energy Market Commission

PO Box A2449,

Sydney South NSW 1235

Submitted on-line via AEMC website

Dear Mr Pierce,

Re : **EPR0019 - Transmission Frameworks Review Issues Paper**

Thank you for the opportunity to comment on the Transmission Frameworks Review Issues Paper, issued on 18 August 2010.

Hydro Tasmania Group

Hydro Tasmania is Australia's leading renewable energy business. We generate hydropower in Tasmania and trade electricity and energy-related environmental products in the Australian market. Since our first hydropower development almost a century ago, Hydro Tasmania has been a leader in renewable energy development and is Australia's largest producer of renewable energy.

Today, the Hydro Tasmania Group includes Momentum Energy, the Victorian specialist electricity retailer. We are also a joint owner of Roaring 40s, which develops and operates wind farms in Australia. Through our consulting arm, Entura, we share our expertise in energy and water with businesses and governments right across the Asia-Pacific region.

Hydro Tasmania's Submission

Hydro Tasmania is a party to separate submissions by the National Generators Forum and The Clean Energy Council on the Transmission Frameworks Review Issues Paper. This submission is focussed on three topics from the issues paper, each of which is related to a specific Issues Paper question. The Hydro Tasmania submission has tried to address these at an issues level, avoiding the advocacy of specific solutions. However, given that the next iteration in the consultation process will involve a discussion of options, we have tried to identify some approaches which might be investigated by the Commission in its subsequent work.

The Hydro Tasmania submission discusses:

1. The nature of evidence in a forward-looking process,
2. Assessing the materiality of congestion,
3. The need (or otherwise) for improved locational signals.

Evidence

> "Question 1 Application of the NEO
>
> Do frameworks governing electricity transmission allow for the minimisation of total system costs and for overall efficient outcomes in accordance with the NEO? What evidence, if any, is there to demonstrate that this is or is not the case?"

Whilst it is possible to gather evidence in relation to the impact of transmission frameworks on past market investment, spot market dispatch and contract market liquidity, the present review is surely more concerned about the robustness of the frameworks to expected future generation growth – primarily growth in remote renewable generation in response to climate change policies.

The materiality of congestion in the past is unlikely to be a sound basis for changes to the transmission frameworks to managing future risks, or a decision to retain the status quo.

Evidence for future impacts is necessarily based on modeling where the context and assumptions are often open to challenge. Consequently, a robust outcome relies on sensitivity analysis on the input assumptions. For example, changes to the RET and uncertainties about carbon pricing, will impact on the validity of some past assessments.

This review will require significant economic/market modeling work, but it is important that any such work be preceded by both consultation to provide a sanity check on inputs and simpler back-of-the-envelope assessments to guide the structuring of the subsequent, more sophisticated models.

Materiality

> "Question 10 Dispatch of the market and management of congestion
>
> Is there a need for material congestion to be more efficiently managed in the NEM?"

Unfortunately, the threshold for 'materiality' has not been defined. For example, it could be taken to mean 'greater than a given percentage of annual Market turnover'. From the perspective of an individual Market Generator, this may not be appropriate, since they would be rather more focused on the impact on their contract portfolio.

In addition, the measure of materiality should not be limited to the incidence of actual congestion, but include also the inhibiting impact of potential network congestion on the liquidity of the contract market – not an easy thing to quantify. However, it is clear that even if a constraint binds only rarely, <u>the risk that it might bind</u> in any given dispatch interval, and lead to constrained-off volume risk, can inhibit a generator from entering the contract market. This means that the contract market impact of congestion is related not to the incidence of actual congestion but to the perceived risk that congestion will lead to a lack of dispatch volume.

Finally, the reason that materiality is important, is that the requirement for a proportional regulatory response means that the measure taken to address congestion should be limited by the Market impacts. For example, the cost impacts of congestion in the dispatch timeframe could be compared with the implementation cost of more efficient congestion management measures. This favours the selection of a congestion management regime which is simpler, and therefore more predictable, rather than one which is complex. It also encourages a regime based on a defined algorithm rather than one requiring active regulatory intervention or operational discretion by AEMO.

Locational Signals

> "Question 6 Network charging for generation and loads
>
> Is a price signal of locational network costs for generators required to promote overall market efficiency? "

Past performance

There is no real evidence to date to show that in the past improved congestion price signals would have led to more efficient locational decisions. For example, South Australia continues to attract new wind investment proposals, even though it has been clear for some time that the transmission network there is at or past its limit. What clearer signal is there than frequent negative spot pricing and the high marginal value of the constraints in South Australia[1] ? It is hard to see that a small (and as proposed relative) spatially-variable component of fixed transmission charges would have altered these South Australian locational decisions, when the significant spot price impacts appear to have had no effect.

Future

Looking to the future, weak locational signals are provided to investors by Marginal Loss Factors, (MLFs). However, these are very limited in the extent to which they look forward. That is, the annual MLF data is based on an eighteen-month forward view of likely new generation and not on the long-range of development options. The long-term impact on MLFs of full development of the potential resource, such as envisaged under the Commission's Scale Efficient Network Extensions, (SENE) proposal, may have a significant impact on existing investments.

Typically, a potential new windfarm investor is faced with access uncertainty, in that the effective Capacity Factor, of their proposed generation may decrease in the future, due to an increase in congestion as a result of other new investment. That is, the next investor in generation will not have a clear economic signal, related to the absolute transmission augmentation costs, and consequently may locate in a way which increases overall costs.

[1] constraint S>>V_NIL_SETX_SETX binding often and both constraint S>>S_NIL_96_WIND, and S>>S_NIL_1_WIND with relatively high marginal value, seem to have little impact on the desire to invest in that already congested region.

Generation/Transmission Optimisation

When an investment decision is being made, a trade-off is required between, for example:

1. a high Capacity Factor windfarm which requires a significant amount of transmission investment, in both the shared network and connection assets,

2. the same potentially high Capacity Factor windfarm, but instead of augmenting the transmission, accepting significant periods of being constrained off, so as to yield an effectively lower Capacity Factor; and

3. a windfarm with a lower Capacity Factor, which is located close to existing adequate transmission and so avoids the need for network augmentation.

Whilst Federal Treasury modeling has suggested that the RET will be achieved, even without significant transmission upgrade work, it is by no means certain that this approach would lead to the most economic solution as required by the NEO.

In the old centrally-planned world, the wise central planner would make tradeoffs, to minimise the cost of the next unit of energy. However, with the present market-based approach, this trade-off will only occur as a result of price signals.

If we fail to provide the right economic signals, we risk building windfarms in places where there may well be the best theoretical Capacity Factor but which will require much more transmission investment, or alternatively not achieve the expected Capacity Factor due to transmission congestion.

What is needed is a calculation of the holistic benefit. The present NEM structure does not incentivise either the TNSP or the prospective windfarm developer to take a holistic approach. Some consideration of MLF (and changes in MLF as the area gets fully developed) is sometimes given by wiser investors. In time, we may start to de-rate Capacity Factors to take into account projected significant constrained-off periods, but individual investors and often not well-placed to make this assessment.

What the preceding discussion highlights, is that to achieve an optimal outcome, <u>each individual network injection point</u> needs to be assessed in terms of its capability. Coarse measures, such as division of NEM regions, (or even ANTS zones) into broad "generation-rich" and "load-rich" sub-zones, will only work if all the points in a sub-zone have approximately the same capital investment requirement to achieve the required injection capability. If this were done, then wherever a proponent chose to connect within a sub-zone, the cost of the consequent transmission augmentation would be the same. This could then be used to determine a spatially differentiated component of fixed transmission charges, to apply to generators making a connection decision.

Existing Renewble Generation

Whilst there is some sense in providing a locational signal for new investors, it makes little sense to impose spatially differentiated fixed transmission charges on established renewable generation – as an incentive for it to retire and release its transmission for potential new renewable generation.

Existing generation is largely a sunk cost. The 2020 renewable energy target is premised on not only incentivising new renewables but on the maintenance of the existing renewable capacity – a goal not furthered by increasing fixed transmission costs for, for example, established hydro generation.

In the example above, the globally optimal solution is probably that the existing hydro generation remain and the location of the new renewable source be decided by the proponent on the basis of competing projects with internalised transmission augmentation costs. This solution will only be arrived at if the proponent sees a pricing signal related to absolute augmentation costs and the established renewable is exempted from a meaningless relocational signal. In this context, it is noted that in the Alberta transmission augmentation model, existing generation is excluded from locational price signals[2].

Links to SENE Consultation

The integration of centrally-planned transmission and market generation is fraught with difficulties but an attempt to do this has been made in the SENE proposal. We seek clarity of process going forward as to how the SENE approach will be integrated with the locational decisions of new renewables as discussed in this Frameworks Review consultation.

In practice, there is a link between any assessment of the need for a locational signal, the form of any such signal and the SENE proposal. This is because the location of new

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[2] Under the Alberta 'Generator System Contribution' requirement, new generators are required to pay a per MW charge for interconnection that depends upon their location; eg See http://www.aeso.ca/downloads/AESO_Generator_System_Contributions_2010-2011_2009-02-11.pdf

renewables will be influenced by the form of any SENE arrangements, and in particular, where the SENE costs and risks are allocated.

Conclusion

In closing, Hydro Tasmania would like to again thank the Commission for the opportunity to comment on the Transmission Frameworks Review's Issues Paper, and stress that it has an open mind about how these transmission issues are best progressed to further the NEO. From our perspective, the important issue at this stage is to leave a reasonable range of options open for discussion, and to have that discussion founded on a clear common understanding of terminology, such as "evidence" and "materiality".

We are very aware of the extent to which these issues are not only inter-related but how they will each impact on the ultimate achievement of the 2020 Renewable Energy Target in a way which meets the NEO.

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

Yours sincerely,

D. Bowker

David Bowker

Manager Regulatory Affairs

Hydro Tasmania