Hydro Tasmania
The power of natural thinking

11 November 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 : ERC0100 - Scale Efficient Network Extensions Options Paper

Thank you for the opportunity to comment on the Commission's 30 September 2010 Options Paper in relation to the proposed National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010.

Hydro Tasmania

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, 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 SENE Options Paper.

This Hydro Tasmania submission does not repeat material covered in our earlier submission on the SENE Issues Paper. Neither does it repeat the discussion, which was presented in our submission to the Transmission Frameworks Review, in relation to the nature of evidence

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concerning future market needs. The present submission is attached and focuses on four questions in relation to the SENE proposal:

1. Is a SENE mechanism needed?
2. What kind of economic test is appropriate?
3. How should SENE costs be allocated? and
4. How should SENE be priced?

Conclusion

In closing, Hydro Tasmania would like to again thank the Commission for the opportunity to comment on the SENE Options Paper.

We are very aware of the extent to which the issues of SENE, Inter-Regional TUOS and development of the wider Transmission Frameworks 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 John Arneaud on 0408 589 513.

Yours sincerely,

Andrew Catchpole

General Manager, Communications and External Relations

Hydro Tasmania

Hydro Tasmania Submission to ERC0100 - Scale Efficient Network Extensions Options Paper

Hydro Tasmania's submission on the Scale Efficient Network Extensions, (SENE) Options Paper focuses on four questions in relation to the SENE proposal:

1. Is a SENE mechanism needed?
2. What kind of economic test is appropriate?
3. How should SENE costs be allocated? and
4. How should SENE be priced?

Need for SENE

In our view, it remains unproven that SENE are needed. Given the difficulties in relation to presenting evidence for the future, we are unsure that this can ever be resolved to the satisfaction of all Market Participants.

However, if there is a policy decision to develop a SENE mechanism, then it is important that the SENE design supports the NEO. Any SENE should release value from economies of scale. The SENE design should not distort locational signals, by externalising transmission costs and allowing Generators to game the regulatory test, in relation to shared network augmentation.

Economic test

<u>Problems with the RIT-T</u> Since the outcome of the RIT-T is so highly dependent on the input data, it is doubtful if such a complex test is justified in the context of SENE[1]. For Customer-driven transmission augmentation, the uncertainty in load projection is averaged out over many potential load points. However, with SENE, the success of the RIT-T is highly dependent on the progression of one or two critical generation developments. The risk of stranding is consequently higher. That is, the level of uncertainty when considering generation investment is much greater than tolerated for normal load-growth projections, as used for a load-justified RIT-T.

<u>Alternative Threshold</u> In place of the RIT-T, it is suggested that a simple hurdle be used, as for Option 1. The actual percentage threshold is a matter of risk appetite. The suggested 25% seems too low, but this is really a matter for public policy – there is a degree of arbitrariness about the threshold. 50% of capital requirement being met by generator commitments may be a better risk balance. Consultation with AEMO and the AER should be mandated and AER approval required, based on (to be developed) guidelines.

A simple threshold would have a major advantage of preventing potential 18-24 month delays if/when the RIT-T modelling assumptions and results are challenged. Given that the RET date is in 2020, and that significant transmission development takes up to seven years from start to finish, it is indeed probable that if a contentious RIT-T process is adopted, then little in the way of physical assets will be in place by 2020.

However, the main justification for avoiding the RIT-T is theoretical, in that because the number of generation investment decisions is small, the kind of statistical averaging which

[1] In addition, RIT-T may be unworkable, given that it relies on committed generation being in place and investors need transmission certainty (in SENE and shared network) before committing.

takes place when considering load growth projections, (as used for Customer-driven RIT-T), is invalid. Load growth may be delayed by a few years, a single large generation investment is much more likely to be deferred for considerably longer. The move to a simple threshold sacrifices apparent precision but does not in our view lose any accuracy, in the context of uncertainty in future generation investment.

Cost Allocation

Generators need to see their consequential efficient costs, to preserve dynamic efficiency, through an appropriate locational signal for their investment decision. That is, if it is more efficient for the market as a whole to avoid developing generation at that node, and thereby avoid augmentation, either as SENE or as necessary shared network upgrades, then that is what needs to happen. Optimal generation location will not occur if the investor sees the associated transmission costs as externalities. As stated (pg 87) in the Options Paper, "if the SENE connected generation is expected to cause more cost on the shared network then it is possible that a SENE project may be privately profitable but socially inefficient."

So the subscribed SENE costs should be passed to connecting generators, but the unsubscribed portion carried by Customers. This Customer stranding risk is justified on the basis that, the decision to overbuild the SENE, (ie beyond the stand-alone requirement of the First Generator) is one of public policy and it is therefore appropriate that Customers fund this increment, until/when additional generation connects.

Pricing

The First Generator (or group of Generators) should be charged at stand-alone cost with subsequent reduction as other Generators connect. Eventually, when the SENE is fully subscribed, then all Generators pay a proportional share of the total SENE cost. At that point in time, Customer charges are zero.

For the First Generator, this is the best deal available – so there is no disincentive to invest. That is, in the worst case, where there is no later generation development, the First Generator is no worse and no better off than in the absence of the SENE arrangements.

Conclusion

We believe that the above features are essential components of any SENE arrangement which meets the NEO. Key points are:

1. The RIT-T is probably unable to deliver significant transmission in the required 2020 timeframe;
2. A capital commitment threshold of 25% of SENE cost is probably too low, but this is seen as a public policy matter – since the risks are ultimately borne by Customers;
3. The subscribed SENE costs should be passed to connecting Generators, but the unsubscribed portion is to be carried by Customers; and
4. The First Generator (or group of Generators) is to be charged at stand-alone cost with subsequent reduction as other Generators connect.

Attachment 1 below lays out a feasible SENE option based on the above approach. Hydro Tasmania asks that if the Commission decides to progress the SENE concept, then the features of this option be considered, rather than limiting discussion to the four options which were presented in the Options Paper.

Attachment 1 – A Feasible SENE Option

This proposal assumes that it is possible to "mix & match" by picking the best features of each of the four SENE options in the Commission's Option Paper.

Features:

- SENE initiation can be either by AEMO via NTNDP, supported by TNSP APR or by First Generator (or group of Generators), through a connection enquiry.
- Total SENE costs are limited to four times[2] stand-alone cost of transmission assets to meet First Generator's transfer requirements.
- No RIT-T or economic test is proposed, on the basis that the key input data – the probability and timing of new generation investment is so uncertain as not to warrant a sophisticated economic test.
- All SENE charges are notionally prescribed transmission services, but annual variation in Generator costs may be managed through a hedge-type arrangement in the individual connection agreements .

Process

1. AEMO identifies draft SENE zones as part of NTNDP.

2. TNSP[3] describes credible connection asset options and impact of SENE on shared network, in their APR.

3. The First Generator's connection enquiry in an existing SENE zone or application for a new SENE zone triggers detailed consideration of a SENE. (Generators will also be able to provide input to the AEMO planning process and in response to the TNSP's APR).

4. The First Generator's connection application may suggest a SENE in a zone not previously identified by the NTNDP as a SENE zone or a different SENE configuration, but in that case AEMO and TNSP may need to provide (a) AEMO comment on implications for NTNDP and (b) TNSP connection asset options and impact of SENE on shared network.

5. TNSP determines required stand-alone design to meet First Generator's needs and develops overbuilding options (beyond that required to meet needs of first

[2] If on reflection the 25% capital requirement threshold is considered too low, then this will need to be altered.
[3] Could be a DNSP but TNSP used here throughout.

Generator(s) connection application) to a maximum total SENE cost of four times[4] stand-alone cost.

6. The TNSP must consult with AEMO and the AER to assist it in determining the final SENE design, based on the options in (5) above. The TNSP may hold a more public Market consultation, for the purposes of refining the SENE design.

7. The final SENE design must be approved by the AER[5] within six months of the receipt of the First Generator's connection application. It is important that a potential SENE does not become a blocker to development of an actual generation project proposal.

8. The First Generator pays the stand-alone cost with the potential for reduction in charges over time as additional Generator(s) or loads connect to the SENE[6]. These payments could be in terms of an annual charge or as up-front payments, by negotiation with TNSP.

9. The TNSP must negotiate financial compensation in relation to the First Generator being constrained on/off on the SENE. [Management of any constraints in the shared network to be addressed under the Transmission Frameworks Review, (TFR)].

10. The TNSP must include provisions in the connection agreement with Generators for the preservation of the Generator's access across the SENE in the event that the network configuration or load connections change, such that the SENE effectively forms part of the shared transmission network.[7]

11. All SENE services are treated as prescribed services. If only the Customer funded part of the SENE were treated as prescribed, (with the Generator-funded part of the SENE assets classified as negotiated), then there would be the need to periodically re-classify previously prescribed assets as negotiated assets as the take up of the SENE increased over time.

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[4] Thus automatically at least 25% of SENE cost is covered by First Generator.

[5] The fallback position is that the AER approves only the stand-alone transmission requirement of the First Generator – no effective SENE arrangements. Some guidelines would be needed for AER approval, but it is not expected that a complex economic test would be performed. The uncertainty in the key input, the probability and timing of new generation, precludes any sensible RIT-T type approach. The AER may take a more conservative approach with Generator-initiated SENE projects under (4) above.

[6] An alternative would be Hydro Tasmania's original proposal that the cost be somewhere between stand-alone and proportional, based on the % capital committed at SENE initiation. Customers would then have an upside as well as a stranding risk, since the SENE, if fully developed, would over-recover from Generators – who would still be better off than if there were no SENE.

[7] This could be difficult unless some progress is made in relation to congestion management under the Transmission Frameworks Review.

12. Generators include in their negotiated connection agreements with TNSP hedging arrangements to effectively fix the annual payments for a defined term, eg 10 years. Absent this, Generators would be exposed to forward connection cost uncertainty, making project financing more difficult. Generators should be no worse under the SENE arrangements than if they were to negotiate access absent a SENE.

13. Subsequent later connecting Generators pay a share of the SENE cost,[8] with that cost between the First Generator's initial stand-alone cost and a cost related to a proportional MW share of the total SENE cost.[9] [Similar hedging arrangements as at point 12 above]

14. The TNSP must include in the connection agreements with later Generators provisions to pay compensation if those Generating units are constrained on or off on the SENE. [Management of any constraints in the shared network to be addressed under the TFR].

15. Each year, Customers pay, as a prescribed transmission asset, the total cost of the SENE, less the SENE payments made by Generators. In the long-term, if all planned generation connects, this annual cost will reduce substantially to zero[10].

This process would lead to the pricing outcomes as shown in the two examples below.

[8] This reflects that the second or subsequent Generator is in practice limited in ability to influence the SENE design or terms. It also avoids the Chapter 6A requirement that transmission assets which have been treated as prescribed cannot subsequently become negotiated. The SENE remains prescribed with the Customer payments detailed as in point 15.

[9] That is a similar reduction as suggested for existing Option 4.

[10] If Hydro Tasmania's original starting point is adopted, then Customers could potentially get a refund over the SENE life – a payoff for carrying the stranding risk and maybe off-setting failed SENE elsewhere..

EXAMPLE 1

Consider a connection application with a stand-alone cost equivalent to M$13 pa. The TNSP decides to build a SENE of four times the capacity with a total SENE cost equivalent to M$40 pa, proportional cost of M$10 pa.

In the first year(s), before the second Generator connects, the charges are as shown in row 1 below. Once the second Generator (for simplicity assumed of equal capacity requirement) connects, the charges to each Generator reduce to M$12 pa. This continues until the third Generator connects, when the charges are as shown in row three. Finally, when the fourth Generator connects, the cost for each one is M$10 and Customers pay nothing.

Time

Costs Paid By / Generator connections	**First Generator**	**Customers**	**Second Generator**	**Third Generator**	**Fourth Generator**
First	Stand-alone cost M$13	M$27	0	0	0
Second	M$12	M$16	M$12	0	0
Third	M$11	M$7	M$11	M$11	0
Fourth	M$10	0	M$10	M$10	M$10

TNSP revenue is maintained throughout the period.

Example 2 - With more complex generator data.

Total SENE cost pa (M$)	**40**	Capacity (MW)	**2000**
First generator stand-alone cost (M$)	**13**		**500**

generator required transfer capacities	500	400	540	560

Costs Paid By / Generator	**First Generator**	**Second Generator**	**Third Generator**	**Fourth Generator**	**Customers**	TNSP Revenue (M$)
First	13.00	0.00	0.00	0.00	27.00	40
Second	12.20	9.76	0.00	0.00	18.04	40
Third	11.12	8.90	12.01	0.00	7.97	40
Fourth	10.00	8.00	10.80	11.20	0.00	40

Stand-alone cost (M$ per MW)	0.026	500	Initial Capacity subscribed (MW)
proportional cost (M$ per MW)	0.020	2000	Final Capacity subscribed (MW)