Dr John Tamblyn
Chairman
Australian Energy Market Commission
PO Box A2499
SYDNEY SOUTH NSW 1235

Submitted electronically: www.aemc.gov.au
Reference: ERC0100

17 May 2010

Dear Dr Tamblyn

SCALE EFFICIENT NETWORK EXTENSIONS

Macquarie Generation, Eraring Energy and Delta Electricity appreciate the opportunity to comment on the Ministerial Council on Energy's proposed *National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010*, dated 15 February 2010.

The MCE considers that the SENE Rule change is necessary to overcome the lack of commercial incentive for network businesses to bear the risk of building assets to efficient scale in advance of future connection commitments and that addressing this lack of incentive reduces the scope for inefficient duplication of assets and ensures that economy of scale benefits can be realised.[1]

We accept that there are economies of scale in the planning, construction and operation of transmission network infrastructure. There may also be high transaction costs in coordinating the joint development of transmission infrastructure by multiple generation investors in remote regional areas. However, we question whether the costs of a complex new regulatory framework have been fully considered. We also explore other market-based and regulatory solutions.

Materiality

The SENE proposal was considered in detail throughout the course of the AEMC's Review of *Energy Market Frameworks in light of Climate Change Policies*. However, at no stage did the AEMC attempt to identify the number of SENE projects that may qualify under the proposed regulatory framework. Nor did the AEMC analyse the extent of possible economies of scale savings from these projects as a way of giving some indication of the possible benefits. Those benefits need to be assessed against

[1] MCE 2010, *Rule Change Request – Scale Efficient Network Extensions*, p.4.

the costs of potentially inefficient new investment as well as the costs of developing and administering the new regulatory framework.

The MCE Rule change proposal is also silent on the scope of possible benefits. The MCE makes the assertion that the "costs associated with inefficient connection assets for clusters of new generators is likely to be substantial".[2] We consider that any Rule change that introduces some 40 pages of new rules and amendments to oversight a complex regulatory approvals process for SENEs should include some analysis of the materiality of the problem being addressed.

The AEMC has indicated that it will assess whether "the potential cost of inefficient duplication of connection assets is material and, if so, whether those costs are likely to be greater than the costs that may arise from asset stranding under the proposed new framework".[3] We would encourage the AEMC to provide some quantification of the possible costs and benefits of these projects in its draft determination, possibly through the inclusion of case studies of potential SENE projects.

SENE planning and approvals process

We appreciate that the Renewable Energy Target and other research, development and deployment funding for renewable projects will result in an increase in renewable generation in areas that are remote from the current transmission system. The introduction of a price on carbon may also encourage additional gas-fired generation in remote areas. At the same time, we have doubts and concerns with the proposed process for reviewing and approving SENE projects.

Generation proponents have an in-built incentive to see SENE projects proceed if the final cost of developing SENE assets is less than the cost of developing standalone connection and extension services. We note that the SENE process only requires one generation proponent to agree to connect to the transmission asset as one of the pre-conditions for approving SENE projects. We are not convinced that one generation proponent provides a sufficient hurdle for approving SENE projects. A more appropriate benchmark would be to ensure that a percentage of the rated capacity of the SENE asset is subscribed before the AER approves a project. We note that the AEMC had suggested a 50% commitment in its earlier consideration of SENE projects.[4]

TNSPs are guaranteed a commercial return on these projects even if they misjudge the level of future generation demand for these services. TNSPs have an incentive to build larger, more costly assets as this will increase the risk-free return on the investment. From our reading of the Rule change proposal, the broader customer base will carry the residual risk if the SENE approvals process results in an over-investment in new transmission assets – the so-called 'stranded asset risk'.

The SENE process places much of the responsibility for assessing the value of SENE proposals with the Australian Energy Regulator. We note that the AER review process

---

[2] MCE 2010, *Rule Change Request – Scale Efficient Network Extensions*, p.6.
[3] MCE 2010, *Rule Change Request – Scale Efficient Network Services*, p.13.
[4] AEMC, 1st Interim Report – Review of Energy Market Frameworks in light of Climate Change Policies, 2009, p.40.

is optional not mandatory. We appreciate that there is scope for public input to the planning and approvals process and there is a role for AEMO to assess the forecasts of generation uptake provided by the TNSPs. The AEMC recognises that “the test of the efficiency of SENE undertaken by the AER is based on an assessment of reasonableness” and that the test “may be interpreted broadly”.[5]

Our main concern is that the SENE approval process may not be as rigorous as the current cost-benefit framework for approving expansions and augmentations under the regulatory investment test that applies to other transmission assets (RIT-T). We are concerned that the AER will be the only independent arbiter of future SENE proposals and that there will not be a detailed economic methodology for assessing the net benefits of these projects.

SENE charging arrangements

If the SENE approvals process results in an over-investment in transmission infrastructure, generation proponents that do connect to an under-utilised transmission line will benefit from lower network charges than would have been the case if they were required to privately fund and develop those assets. Customers ultimately bear the risk if there is an inefficient level of investment in SENE assets.

Clause 5.5A.13 of the proposed Rules requires that the AER to set an annual charge for those generators that connect to the SENE at a level sufficient to recover the present value of the SENE over its economic life based on the *forecast generation profile*. Such a Rule could be interpreted in different ways (see Box 1).

We are concerned that the current drafting of the Rules supports the pro-rating of SENE costs between generators and customers on an average cost basis (approach 1). Such a charging methodology exposes customers to the full cost of all stranding risk. Connecting generators bear no risk and are charged an amount that may be substantially below their next best alternative – a standalone investment. Renewable energy projects that are currently subsidised through the RET mechanism could receive a further regulatory advantage in the form of lower network charges underwritten by transmission customers. Other generators, including those investing in low emission technologies located close to major load centres, would be placed at a competitive disadvantage.

If the SENE proposal proceeds, we consider that approach 3 would minimise possible distortions. Customers bear some of the up-front risk if there is a low initial uptake of the SENE. Generators pay an amount up to the cost of the standalone project cost if the SENE is under-recovering aggregate costs. When there are sufficient generators subscribed to the SENE and the standalone costs for each exceeds the SENE costs, the annual charge would be revised downwards towards the point where each generator is bearing its share of the extension asset. Those annual charges would not have to exactly match the SENE costs. It would still be efficient to charge a margin above the shared costs as connecting generators face the alternative of a standalone project. The margin would be rebated to customers as a way of recognising the risks they faced when underwriting the SENE in the early years.

[5] MCE 2010, *Rule Change Request – Scale Efficient Network Services*, p.15.

Box 1: Stylised example of SENE charging arrangements

A SENE project with one-off capital costs of $400 million that delivers 1000MWs of rated capacity from the remote hub to the shared network. The TNSP forecasts that five generators will connect to the SENE asset and each generator will dispatch a maximum of 200MWs. The standalone cost of building individual 200MW lines is $150 million. Two generators connect to the SENE in year 1. The SENE project has an economic life of 20 years. SENE costs include planning, capital and operating costs. The AER may vary the charges that the TNSP recovers from connecting generator each year.

Approach 1 (average costs): The TNSP charges an average cost to the first two generators at a level that would recover $80 million ($400 million ÷5) over the life of the project (assuming that the TNSPs forecast of the likely uptake is correct). The TNSP recovers $160 million in costs. If the other three generators fail to arrive, consumers will bear the stranded asset risk of $240 million. The first two generators will benefit by $70 million – the difference between the $150 million standalone cost and the $80 million charged by the TNSP.

Approach 2 (standalone costs): The TNSP annual charges in year 1 is set to recover an amount just below the standalone cost of the two foundation generators - $150 million each, or $300 million in total. Customers underwrite the remaining $100 million of costs. If in year two a third generator connects to the SENE, the TNSP again charges something just below the generator's standalone cost. The SENE is now recovering $450 million (3x$150 million) and consumers bear no residual stranding risk. In this case they would receive a rebate of $50 million. If further generators connect, the level of cost recovery increases and the additional revenue is rebated to customers.

Approach 3 (shared costs): The TNSP charges for the first 2 generators in year 1 are set at standalone costs – the SENE recovers $300 million (2x$150 million) and customers fund $100 million. If the remaining 3 generators subscribe to the SENE in year 3, each generator is charged an equal share of the SENE costs – $80 million ($400 million ÷ 5). Customers bear no ongoing costs for the SENE.

If SENE projects deliver significant economies of scale, the project may not require a high level of subscription before costs are recovered and customers are relieved of the stranding asset risk. Approach 3 allows the AER to set SENE charges at level between shared and standalone costs. The greater the economies of scale, the lower the point where a charge just below standalone costs for each connecting party would be sufficient to fund the SENE.

It follows that an arrangement where connecting generators must make firm commitments for a fixed proportion of the SENE asset would minimise customer risk. This could be in form of agreeing connection offers or through a non-refundable, up-front deposit for a firm allocation of capacity rights.

What the above discussion does reveal is how complicated the SENE charging arrangements are likely to be. With multiple parties connecting at different times in various locations, the AER will have a difficult task in reviewing and setting annual charges.

Alternative ways of realising economies of scale benefits

The following sections look at alternative ways of achieving the stated goal of realising economies of scale for network assets that connect clusters of remote generation. We consider that any proposal that puts forward complex new regulatory structures should be tested against the existing regulatory framework and possible market-based alternatives.

Applying the Regulatory Investment Test for Transmission

The AEMC's Consultation Paper indicates that the Commission intends to assess whether the RIT-T could be used to assess network extensions as part of its analysis of likely outcomes of the status quo. Under this framework, consumers would pay the full cost of the network extension where the RIT-T assessment finds that the investment will deliver net benefits. Generators would continue to pay the cost of their own connection asset. The AEMC does not include any detailed description or consideration of this option in the Consultation Paper.

The AEMC's First Interim, Second Interim and Final Reports for the *Review of Energy Markets Frameworks in Light of Climate Change* released in 2009 discussed the concepts of remote SENE (originally NERG) hubs. The AEMC has at no stage explained why SENE-style projects could not be considered under the existing RIT-T process for assessing the merits of shared transmission assets.

The AER's draft *Regulatory Investment Test for Transmission Application Guidelines*, March 2010, (the "guidelines") notes that Clause 5.6.5C of the Rules provide that a TNSP must apply the RIT-T to all proposed transmission investments unless the investment falls under the defined circumstances. A transmission investment is defined in the Rules as:

> Expenditure on assets or services which is undertaken by a transmission service provider or any other person to address an indentified need in respect of its transmission service.

The defined circumstances listed in the Rules states that RIT-T need not be applied where the "cost of the proposed transmission investment is to be fully recovered through charges for negotiated transmission services. Negotiated transmission services are described in the Rules as connection services that are provided to serve a Transmission Network User, or group of Transmission Network Users, at a single transmission network connection point. We are uncertain whether the extension services between remote connection hubs and the shared network would fall within this category. If this is the case, the question arises as to whether the Rules should be amended to allow extension projects to be assessed as part of the RIT-T process.

The RIT-T guidelines set out a detailed and thorough process for assessing transmission investments:

1. Identify a need for the investment
2. Identify the base case and a set of credible options to address the identify need
3. Identify a set of reasonable scenarios that are appropriate to the credible options under consideration

4. Quantify the costs of each credible option
5. Quantify the expected market benefits of each credible option – calculated over a probability weighted range of reasonable scenarios
6. Quantify the expected net economic benefit of each credible option and identify the preferred option as the credible option with the highest expected net economic benefit[6]

The Rules require that the RIT-T be based on a cost benefit analysis which includes “an assessment of reasonable scenarios of future supply and demand if each credible option were implemented compared to the situation where no option is implemented”. The RIT-T states that the market benefit of a credible option is obtained by comparing, for each relevant reasonable scenario:

1. the state of the world with the credible option in place; with
2. the state of the world in the base case.

The RIT-T guidelines define the state of world as a description of all of the relevant market supply and demand characteristics if a credible option proceeds. This includes the pattern of new generation (incorporating capacity, technology, location and timing) under each credible option. The calculation of the market benefit for a given credible option involves a probability weighting of the benefits arising from that option across a range of reasonable scenarios.[7]

We are of the view that the RIT-T should allow TNSPs to evaluate a range of reasonable scenarios including those where generators are expected to arrive in remote locations if a transmission asset is constructed. While there will always be some uncertainty about the number and timing of such investment decisions, if it is a probable state of the world it would be considered as part of the cost-benefit framework set out in the RIT-T.

Applying the RIT-T process would also enable better co-ordination of decisions where the proposal involves the connection of remote generation and the augmentation of the existing shared transmission system.

The RIT-T has undergone much scrutiny and improvement since it was originally designed. It provides a rigorous process for quantifying all relevant costs and benefits using a probabilistic framework. There are clear procedures for industry input and resolving disputes. We are concerned that the SENE rule change process, if implemented, would result in an entire new regulatory process with weaker checks and balances on TNSP investment decisions.

If there are clauses in the Rules that prevent the RIT-T applying to extension assets, the AEMC should consider amending the existing Rules to facilitate the application of the regulatory test to these projects.

---

[6] AER, *Draft Regulatory Investment Test for Transmission Application Guidelines*, March 2010, p.7.
[7] AER, *Draft Regulatory Investment Test for Transmission Application Guidelines*, March 2010, p.14.

Merchant investment in network extensions

We support the general principle that where a generator or network service provider has invested privately in assets that are not part of the shared transmission system, the investor should have full property rights over the use of those assets. Generators should not be able to connect to an extension service unless they have negotiated the terms and conditions of well-defined access arrangements with the parties that have paid for the construction and operation of that service.

We have a concern that the proposed SENE model will crowd-out private investment in network assets between remote hubs and the existing shared network. In many cases, generators and NSPs will have the best knowledge and understanding of the available fuel resource in specific locations and other factors that are likely to attract investment through time.

A NSP or generator that is able to invest in an extension service that includes some spare capacity may find it commercially attractive to make the initial investment. Private investment would prove profitable if there was sufficient interest from new generators and they were willing to pay an access or usage fee that was less than the standalone costs of a building a duplicate connection and extension asset.

As discussed earlier, if a SENE project delivers significant economies of scale and there is sufficient demand to locate in a remote region, it may only require a relative small share of the privately-funded project to be subscribed before the investor breaks even on the capital cost of the project. The revenue from any further connections would be mostly straight profit, assuming the new generator pays all connection costs. In this situation, the incremental cost of adding further connections, up to the point where the line is fully utilised, is close to zero.

The merchant investor may also be able to recover a portion of its costs by selling options over the capacity rights to prospective users. The sale of options would provide some indication of the likely value and uptake of the extension line through time. This should help merchant investors to access the finance necessary to fund the up-front capital costs of developing these assets.

The AEMC recently finalised its determination of the *National Electricity Amendment (Confidentiality Provisions for Network) Rule 2009*. The Rule determination allows NSPs, in certain circumstances, to share information between prospective connection applicants. These amendments remove some confidentiality obligations and should give potential generation investors at the connection enquiry stage a better understanding of the potential demand for connection services at a particular geographical location. Generation proponents considering a merchant investment in extension services would then have the option of pursuing a joint transmission investment with other generators in the region.

Summary

Macquarie Generation, Eraring Energy and Delta Electricity are concerned that the SENE proposal will create a complex new regulatory approvals process for a sub-set of transmission assets. We are not convinced that such an arrangement has any advantages over the wider application of the existing RIT-T framework. If projects are not able to pass that test, recognising that it allows for probable yet uncertain projects to be included in the assessment of credible options, we would question why such projects should get up under a weaker SENE process.

The SENE proposal may also discourage market-led investments in transmission infrastructure. Such private arrangements would obviate the need for complex regulatory rules for resolving questions about the allocation of capacity rights, charging arrangements through time and possible compensation payments.

SENE projects may or may not result in efficient investments. It is highly unlikely that the proposed regulatory framework will result in 'right-sized' investments in all cases given the difficulty of forecasting demand and supply patterns in future years. If the AER is not an effective check on the approvals process, the most likely outcome is for TNSPs to over-invest in the number and scale of these projects.

The NGF submission to this Rule change proposal outlines a number of concerns and questions with the application of the SENE regulatory regime. While we do not support all of the comments raised in the NGF submission, we share similar concerns with those aspects of the submission that raise potential problems with the implementation of the SENE Rules.

Yours faithfully

MR RUSSELL SKELTON
MANAGER MARKETING
& TRADING
MACQUARIE GENERATION

MR ANTHONY CALLAN
GENERAL MANAGER
MARKETING
DELTA ELECTRICITY

MR TIM BAKER
GENERAL MANAGER
MARKETING STRATEGY
ERARING ENERGY