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13 May 2010

The Chairman
Australian Energy Market Commission
PO Box A2449
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Submitted via website www.aemc.gov.au

Dear Dr Tamblyn,

AGL Energy welcomes the opportunity to comment on the consultation paper for the proposed *National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010*.

As Australia's leading investor in renewable energy in Australia, AGL is well placed to comment on transmission policy. AGL operates across the supply chain and has investments in coal-fired, gas-fired, renewable and embedded electricity generation and electricity retailing. AGL is Australia's largest private owner, operator and developer of renewable generation in Australia and has invested well over $2 billion in renewable energy and has much more in its portfolio of development opportunities. By the end of the decade, AGL will own or operate approximately 1,420 MW of renewable energy generation assets.

AGL accepts that the Australian Energy Market Commission (AEMC) under the direction of the Ministerial Council on Energy (MCE) is seeking to ensure that the economic framework for network extensions accommodates broader energy policies and continues to deliver on the objectives of the National Electrcity Rules. However, AGL contends that the proposed Scale Efficient Network Extensions (SENE) model places electricity consumers at risk of paying for poor investment decisions. These decisions are to be made by proponents who are best placed to not only reap the rewards, but also wear the risks of network extensions. AGL notes that as an overarching public policy principle, if governments consider there is a market failure in the current economic framework, it is preferable for government to directly invest on budget rather than seek to expose consumers to the risk of stranded assets. In this submission AGL details its opposition to the SENE proposal based on a range of criteria, concluding that the SENE proposal:

- Conflicts with general principles that should govern transmission policy;
- Is moving ahead of testing the existing economic framework, including the forthcoming RIT-T;
- Inadequately emulates the investment decisions that only those who are prepared to financially commit can make;
- Lacks a sound economic test; and
- Strays from energy infrastructure build in comparable industries.

Finally, should the SENE proposal continue to be progressed despite key shortcomings, AGL offers some enhancements to curtail the consumer-exposed risks of this rule change. As an attachment to this submission, AGL provides a review of the SENE Rule Change undertaken by Frontier Economics Consulting, to assist in the AEMC's deliberations.

Principles for transmission policy

AGL contends that transmission policy should be set in a way which ensures economic efficiency (including allocative, dynamic and productive efficiency) is maximised while security of electricity supply is maintained. To assess the SENE proposal against overarching principles for transmission policy, AGL has prepared the following principles. They are considered to be consistent with the objectives of the National Electricity Rules and provide for a competitive market. A critique of the SENE proposal is provided against each principle:

1. Transmission policy should deliver efficient transmission prices which incentivise generation proponents, all other things being equal, to locate their investments as close to load centres as possible. *The SENE proposal may nullify this principle, resulting in generation proponents being indifferent to distance from load centres.*

2. Extensions of transmission networks should be financed solely by the benefiting entities. Only where existing infrastructure is upgraded to the benefit of other participants as well as connecting entities can the costs be appropriately shared across all the benefiting parties. Impacts of additional charges on existing generators should be minimised unless those generators are the proponents of the augmentation. *The SENE proposal in effect provides for consumers to fund extensions, and deep network charges need further resolution.*

3. The risks and returns of developing infrastructure should be appropriated on the same entities. In other words, policies that ensure economic returns flow to generation proponents and transmission network service providers (TNSPs) for investments made should ensure that the risks of failure are apportioned towards these same entities. *The SENE proposal transfers the downside risks to consumers, whilst apportioning all upside risks (returns) to initial and any subsequent investors.*

4. Electricity customers should not be required to underwrite the development of transmission services as customers do not receive any share of the profits, should the investments generate economic returns. In other words, policy settings should not privatise profits and socialise losses. *The SENE proposal as noted in the discussion paper requires customers to underwrite the risk of any under-utilised capacity, despite not being in a position to be an informed investor.*

AGL considers that most of the risks and inequalities stemming from the SENE proposal stem from these four principles.

Existing transmission framework

There are two approaches to network extensions, either through the regulatory process, or alternatively through parties directly engaging to establish a cost sharing basis for augmentation. AGL considers that within this existing framework, a market failure has not been evidenced that warrants the SENE proposal.

Regulatory framework

The regulatory test; and its successor, the Regulatory Investment Test for Transmission (RIT-T) provide the framework for regulatory determined network extensions. It is noted with concern that the SENE proposal is being progressed before the RIT-T is fully developed by the Australian Energy Regulator (AER) to replace the regulatory test for transmission.

The RIT-T aims to promote transmission investment where it is likely to maximise the net present value of benefits to the market compared to alternatives. In calculating the market benefits a TNSP is required to consider a number of reasonable scenarios and weight them to expected probability. When considering a new regulated network extension to a location with no existing, but presumably at least one planned/committed generation plant, a TNSP can consider a range of future possibilities, including:

- Many new generators appearing in the region, or

- Few, if any, other than the one (or more) that have committed and prompted the extension request.

In this regard, there is no barrier to network extensions to remote locations, or areas with little existing generation under the draft RIT-T. Furthermore, with the provision of a "open-season" for information sharing, an TNSP, together with those most informed about potential generation plant, can prepare the most likely, and plausible scenario for generation build, and subsequent network extension.

The RIT-T actually facilitates the process for establishing the most plausible investment scenario for new generation, and it is the scenario which presents the most net beneficial outcome that satisfies the RIT-T. As such, any investment scenario that does not satisfy the RIT-T, can be considered to be either implausible or result in a sub-optimal outcome from a market-wide *ex-ante* perspective.

AGL is not satisfied that current drivers for new generation have exposed a market failure in the RIT-T framework or that meritorious plans for new generation plant will be overlooked in terms of network extension and capacity. The case for allowing the RIT-T to be tested in operation is further underlined in the context of the broader transmission review slated for this year.

Risks of regulatory stranding

One of the key issues that the SENE proposal seeks to address is the potential absence of incentives for TNSPs to build appropriately sized capacity network extensions. In particular the risk that a TNSP may be left with a "stranded asset" if anticipated generation plant doesn't eventuate.

The AEMC's November 2006 Rule Determination adopted the "lock-in and roll-forward" approach that the ACCC identified as a solution to any risk of asset revaluation jeopardising TNSP investment certainty. Ultimately, it is considered that the only remaining scope for regulatory stranding under the Rules is in Schedule s6A.2.3(a).

However, AGL considers that s6A.2.3(a) is unlikely to pose a risk to regulatory stranding in the case of serving generators. The policy intent of this section is focused on managing the risk of large load customers disconnecting, as such, the TNSP would likely only be exposed if no generation eventuated on the network extension. It is noted that this section of the Rules is not explored in the discussion paper.

Open framework under the Rules

Where a proposed network extension is determined not to pass the regulatory test (in future the RIT-T), interested parties may still proceed with an investment. There are no barriers in the Rules preventing generators from entering cost-sharing arrangements, and TNSPs are free to be the arbiters and executors of such agreements.

AGL contends that where market participants are prepared to financially commit to a likely future generation location that does not satisfy the RIT-T, they are free to structure arrangements to adequately extend a network to the anticipated region. The open season process will further provide for these arrangements, and effectively allow those who are most informed, to take on the associated risks of extensions and new build.

SENE emulation of investment decisions

The decision to build a power station requires engagement of a diverse range of assessment criteria to indicate that the project will be economic. Not only are the criteria multi-disciplined, but the decision makers are also spread across a range of disciplines. Given the complexity and risks associated with such investment decisions, AGL contends that the risks of investment, both upside and downside should remain the preserve of those best placed to manage them. Furthermore, the SENE framework of checks and balances, including AEMO approval being a condition precedent for the AER decision is considered to poorly emulate the investment decision process.

In AGL's submission to the AEMC's *2nd Interim Report on the Review of Energy Market Frameworks in light of Climate Change*, analysis indicated that approximately one third of new generation plant announced between 1998 and 2008 proceeded to construction phase. Noting that there is often a degree of difference in commitment to an announced plant and the one that had progressed to advanced planning, the one in three success rate serves as a useful basis for considering the complexities and challenges in building a power station.

Commitment to build new plant requires input from a host of expertise with discrete skills in a range of fields. The spectrum of commitment from announcement through to construction ultimately requires a satisfactory view from:

- investment banks - to assess the probability of success of equity capital raisings (which is important giving diminishing investments by Government Owned Generators);
- corporate institutional and project finance banks - to assess the probability of success of structured and project finance raisings;
- merchant utility energy trading desks - to assess whether the commodity hedge contracts are profitable, bankable and reflect an appropriate allocation of risk;
- engineering firms - to assess whether the technology, and the manufacturer selected represents a bankable proposition; and
- power development business units of the utility businesses sponsoring such projects - to assess whether the project is in fact likely to be committed to by a Board of Directors.

The SENE proposal suggests that the AER, together with input from AEMO would substitute or emulate much of this investment commitment process, in the interests of pursing network capacity that is adequate for future build. However, in the absence of those who are willing to financially commit to their view on likely generation build, AEMO and AER will effectively be speculating on plausible scenarios that may come to realisation with electricity consumers wearing the risks of this speculation.

The rule change request emphasises the importance of a SENE application featuring a robust forecast of future generation connection requirements. As recognised in the discussion paper, this requirement of the SENE proposal places considerable expectations on AEMO and the AER, to be multi-skilled and fluent in the decision making process for new generation plant investment. AGL contends that such expectations are undue, and provide evidence of the risks of the SENE proposal. Without any financial commitment involved, today's forecast can easily become tomorrow's non-reality, with consumers wearing the risk of this speculation.

Economic efficiency test

The SENE proposal features a number of procedures aimed at minimising the risks to consumers. These include a requirement of least one generator committed to connecting, an AEMO assessment of the NSP's forecasts and ultimately the AER's capacity to disallow if it considers the generation forecasts or cost estimates are not sufficiently robust.

There is however a distinct lack of an economic efficiency criterion or test that should be met for the investment to proceed. The absence of such a test challenges the notion that a SENE investment will pursue the long-term interests of consumers, as required by the NEO. Based on the drafting, cl5.5A.8(c) allows the AER to reject a proposal on the grounds that is not reasonable across a range of criteria, none of which require evidence of a net benefit being delivered by the SENE over the duration of its economic life.

The draft Rule does not allow the AER to reject a SENE investment on the grounds that it does not maximise net market benefits. Furthermore, it would appear it cannot reject a SENE investment that results in net costs to the market. In the context of a SENE investment not being subject to the RIT-T, AGL notes there is a real risk that proposed network extensions can actually shop between regimes, to achieve the most preferred outcome.

Finally, AGL suggests that the potential for a SENE investment that yields net costs to the market may directly conflict with the Rule-making test in section 88 of the NEL.

Experience in other energy infrastructure

The gas industry routinely manages the situation that is addressed by the SENE proposal, that is, a large fuel source with a number of users who are competing with each other to get the fuel to a common location. In that industry, participants jointly arrange the construction of necessary facilities to service their needs without recourse to public subsidy or regulatory intervention.

In the example of Queensland Coal Seam Gas (CSG), it is observed that the risk of inappropriate capacity will continue to remain with producers, consistent with the price-taking nature of the LNG export industry in Australia. This paradigm would also apply to other greenfield infrastructure such as rail used for transporting coal and iron ore to shipping ports.

AGL notes that it will be possible, under proposed information sharing arrangements, for TNSPs to act like pipeline developers in the gas industry and provide the necessary information to allow generators to jointly define their needs and negotiate jointly with that TNSP.

A key difference between other energy infrastructure and the electricity transmission framework is the right to capacity that is funded by the proponents. AGL notes that this issue is being addressed in later reviews by the AEMC, which further supports the contention that the SENE proposal should not proceed ahead of the broader transmission review.

Approaches to progressing

In this submission, AGL has identified several flaws and reasons for the SENE proposal to not progress, or at least prudently be suspended until the RIT-T has been exercised and the broader transmission review has concluded. However, should the AEMC elect to progress a consumer-subsidised model for transmission policy, AGL offers the following enhancements to strengthen the model, and reduce the risks to consumers of underwriting stranded assets.

To assist AEMO inform its view on a SENE investment application, beyond public submissions, it should be obliged to seek advice from appropriate, identified expertise that would typically be engaged in such an investment decisions. At a minimum, AGL contends that AEMO seek independent, expertise advice from:

- Technology and engineering sources (such as universities and other industry bodies, such as the Australian Centre for Renewable Energy) – to ensure that generation identified in forecasts, and the proposed capacities are consistent with prevailing expert opinions. In this context, proponents of new generation types should be required to identify similar sized projects to their own somewhere in operation, to ensure transmission is not built to areas where the technology does not work when deployed; and

- Finance and investment sources – to ascertain a view on the potential "bankability" of generation forecasts that feature in the SENE investment application.

It is considered that any project proponent for a SENE should be required to go beyond evidencing reasonable forecasts, and subject the extension to a cost-benefit assessment. In imposing this obligation, proponents should be required to demonstrate the extension satisfies a robust assessment that is similar to that of the regulatory test/RIT-T.

Finally, the AER should be empowered to reject a SENE investment if it determines that the SENE investment has not passed the cost-benefit test. This will ensure that the AER has adequate discretion to be final arbiter of a SENE application, regardless of the proponent, or AEMO's view of its merits. Again, as noted earlier, the emergence of the SENE framework could lead to regime shopping by project proponents, and these recommended enhancements will reduce perceived "easier pathways" to regulatory approval.

Conclusion

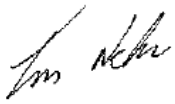
AGL welcomes the opportunity to comment on the SENE proposal for network extensions to connect new generation plant. As noted, AGL does not support the SENE framework as it strays from principles of consumer interest in transmission, is moving ahead of the RIT-T and broader transmission review, cannot adequately emulate the investment decision process and is absent of a robust cost-benefit test.

AGL recommends that the SENE proposal is not progressed at this time, and suggests a trigger for further consideration may follow, once the RIT-T has been fully exercised in the transmission marketplace and the AEMC has had the opportunity more holistically review the economic framework for transmission. Finally, AGL notes that as an overarching public policy principle, if governments consider there is a market failure in the current economic

framework related to private sector proponents being unable to take risks in constructing these assets, it is preferable for government to directly invest on budget rather than seek to expose consumers to the risk of stranded assets.

Should you have any questions or comments, please contact Simon Kelley, Manager Economic Policy and Regulation on (03) 8633 7152 or at skelley@agl.com.au or myself on (02) 9921 2516 or at tanelson@agl.com.au.

Yours sincerely,



Tim Nelson
Head of Economic Policy and Sustainability

Attachment – Frontier Economics Consulting review of the SENE Rule Change

Scale Efficient Network Extensions

A REPORT PREPARED FOR AGL

May 2010

Scale Efficient Network Extensions

1 Introduction

Frontier Economics (Frontier) has prepared this report for AGL Energy in response to the Australian Energy Market Commission's (AEMC's) Consultation Paper for National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010, dated 1 April 2010 (SENE Consultation Paper).

Frontier considers that the Scale Efficient Network Extensions (SENE) concept is unnecessary and flawed:

- Unnecessary – because there is already adequate scope within the National Electricity Rules (Rules) to manage the twin problems of 'right-sizing' new network infrastructure and coordinating multiple new connection applications. In our view, the existing arrangements reflect no outstanding 'market failure' that requires addressing through a new network investment regime.

- Flawed – because neither the SENE Consultation Paper nor the draft Rule change sets out clear economic criteria under which SENEs will be developed. Such criteria are essential to ensure that the draft Rule change satisfies the Rule-making test (see below).

If, nevertheless, policy-makers wish to promote certain types of network investment, it would be more appropriate for this to be done explicitly through direct government expenditures rather than through implicit subsidies funded by electricity consumers.

This report is structured as follows:

- Section 2 explains how the current network regulatory regime in the Rules adequately deals with the issues that the SENE proposal is purportedly designed to resolve.

- Section 3 explains the key flaws of the SENE proposal in the context of the national electricity objective and Rule-making test.

- Section 4 reviews aspects of the Australian gas industry to indentify similar infrastructure challenges and provide precedents that have application to electricity transmission.

- Section 5 suggests potential incremental changes to design of the SENE proposal if the AEMC remains of the view that it is worth pursuing despite the points raised in this report.

- Appendix A highlights more detailed policy and drafting issues arising out of the draft Rule attached to the SENE Consultation Paper.

2 Adequacy of the current regulatory regime

This section explains how the current regulatory framework in the Rules adequately addresses the key issues that the SENE proposal is designed to resolve.

2.1 Key drivers of the SENE proposal

The key driver of the Ministerial Council on Energy's (MCE's) SENE Rule change request was a perceived market failure in network planning and investment, described by the MCE as follows:

> The existing connection framework makes it difficult for a network business to develop a connection solution that would be efficient for multiple connecting parties in the same location over a period of time. When connections cannot be coordinated or built to an efficient scale, there is a risk of inefficient duplication in network assets and potential delays in connection. Given the size of the assets required to connect some forms of renewable generation, and the scale economies available in network provision, the cost impact on customers from such inefficiencies may be large.
>
> Building optimally sized extensions to accommodate future connections requires someone, such as the network business, to take the risk that future generation capacity may not materialise. The existing framework does not provide network businesses with a commercial incentive to build network connections to an efficient scale to accommodate anticipated future connections. If the predicted generation does not eventuate, the network business would have a connection asset but no-one to recover the cost from, leaving it with a "stranded asset". It is also unlikely that the initial connecting party would be willing to pay for the excess connection capacity given it is likely to facilitate a future connection of a competitor.[1]

The SENE Consultation Paper describes three issues under the existing regime that the AEMC considers may lead to sub-optimal network investment:

- The connection of multiple generators in proximate locations.
- The time period over which generators might seek connection.
- A lack of incentives on NSPs to build scale efficient network extensions for connections.[2]

The AEMC noted that the recent Rule change initiated by Grid Australia to enable NSPs to share information received through the connection applications

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1 MCE, *Rule change request, Scale Efficient Network Extensions*, February 2010, p.4.

2 SENE Consultation Paper, p.5.

process should overcome the first of these issues. Therefore, the AEMC appears to be of the view that there is no longer any market failure in cases where a number of generators are simultaneously seeking to connect to the shared network via a large network extension. However, the AEMC suggests that the risk of market failure remains where generators may connect at different times or, more broadly, where the optimal size of a network extension is larger than the size intending connecting generators are willing to fund.[3]

2.2 Lack of a status quo comparison

In our view, the MCE and AEMC's concerns regarding the risks of inefficient network investment under the existing regulatory arrangements are misplaced. In other words, we do not believe that the existing NEM arrangements reflect an outstanding market failure that warrants further regulatory intervention in the form of the SENE proposal.

Unfortunately, although the SENE Consultation Paper states[4] that it will compare the effects of the Rule change proposal with the status quo arrangements – which include the market benefits limb of the regulatory test and RIT-T – it does not do this in any meaningful way. The only commentary in the SENE Consultation Paper of likely outcomes under the status quo is as follows:

> NSPs currently receive no benefit from, and will potentially occur [sic] significant costs, if they oversize their network assets in anticipation of future connections that do not eventuate. Consequently, NSPs are unlikely to consider the possible scale efficiencies that could be achieved by sizing new assets to enable the more efficient connection of potential future entrants. This could lead to the unnecessary duplication of connection assets as each new generator connects, potentially resulting in significantly higher costs for consumers.[5]

and

> Under the current framework it may be difficult for new entrants to connect to the shared network where they would be required to fund the full cost of connection from a potentially remote location - where renewable resources are likely to be located - to the shared network. By reducing connection costs, SENEs should promote greater levels of new generation investment than might otherwise occur, reducing prices in the wholesale market by facilitating increased competition.[6]

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3 SENE Consultation Paper, pp.5-6.

4 SENE Consultation Paper, p.9 and footnote 19, p.15.

5 p.6.

6 p.21.

At no stage does the SENE Consultation Paper consider the scope for economically net beneficial network extensions to be approved under the economic benefits criterion in the regulatory test or the RIT-T. This is a major shortcoming of the paper.

The next sub-section seeks to demonstrate how the impending RIT-T arrangements combined with other elements of the network regulatory regime address the concerns related to SENEs raised by the MCE and AEMC.

2.3 Potential outcomes under the RIT-T

2.3.1 Purpose of the RIT-T

The RIT-T is, as required by the Rules, presently being developed by the Australian Energy Regulator (AER) to replace the regulatory test in relation to transmission investments. The RIT-T, like the regulatory test, is geared towards promoting transmission investment where it is likely to maximise the net present value of benefits to the market compared to a range of alternatives.[7] Under the draft RIT-T, a TNSP is required to calculate market benefits under a number of 'reasonable scenarios' and weight them according to each scenario's expected probability.[8]

There is no barrier in the draft RIT-T or the Rules to applying the RIT-T to SENE-type investments – network extensions to remote areas with little or no existing generation plant. When considering a new regulated network extension to a location with no existing generation plant, a TNSP is required under the RIT-T to consider the full range of reasonable future possibilities. For a SENE-type investment this could range, for example, from:

- very few new generators arriving in the hitherto unconnected location to
- many new generators subsequently arriving in that location.

In this way, the RIT-T provides for the TNSP (as well as market participants and the AER) to weigh up the various risks and costs and benefits of a transmission extension under various future scenarios. As with other network augmentations, it is only if a proposed network extension is likely to be the most net beneficial option in light of these reasonable scenarios that the investment will satisfy the RIT-T. By implication, an investment that does not satisfy the RIT-T will be sub-optimal from a market-wide *ex ante* perspective.

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7 See Australian Energy Regulator, *Regulatory investment test for transmission, Draft*, March 2010 (Draft RIT-T), available here, p.1 ('Purpose') and note 1, p.3.

8 Draft RIT-T, note 4, pp.3-4.

In short, there is no reason why meritorious scale efficient network extensions could not, or would not, be assessed under the RIT-T and proceed or not proceed in accordance with the national electricity objective. We therefore question the need for an entirely new and distinct regulatory regime specifically for SENEs that will complicate and confuse the regulatory arrangements for transmission.

2.3.2 Scope for regulatory stranding

As noted above, the SENE Consultation Paper and the MCE Rule change proposal suggest that the existing arrangements may not provide TNSPs with appropriate incentives to develop scale efficient network extensions because of the risk that the TNSP will be left with 'stranded assets' if the predicted new generation does not eventuate.[9]

However, the scope for TNSPs to experience regulatory stranding (such as in the form of *ex post* optimisation) under the existing Rules framework is extremely limited. The risk of regulatory stranding of sunk transmission assets under the former National Electricity Code arrangements was effectively removed by the ACCC in its 2004 Statement of Regulatory Principles (SORP).[10] In the SORP, the ACCC found that the scope for periodic revaluation of a TNSP's assets could lead to substantial uncertainty for TNSPs (and their customers) and thereby deter efficient network investment.[11] Therefore, the ACCC chose to adopt a 'lock-in and roll-forward' approach to asset valuation to provide greater certainty for investment.

The lock-in approach to transmission asset valuation was confirmed in the AEMC's 2006 Rule Determination on the economic regulation of transmission services.[12] Under this approach:

> …the [Regulated Asset Base] would not be subject to optimisation at regulatory resets to reflect the economic value of the assets to users, which would otherwise present a significant risk to investors.[13]

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9 MCE Rule change request, p.4 and SENE Consultation Paper, p.6.

10 Australian Competition and Consumer Commission, *Statement of principles for the regulation of electricity transmission revenues – background paper, Decision*, 8 December 2004, available here.

11 SORP, pp.40-41.

12 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No.18*, 16 November 2006, pp.97-100.

13 p.98.

Further, the AEMC ruled out any prospect of an *ex post* prudency review of a TNSP's capital expenditure on the basis that:

> An *ex post* review effectively requires the regulator to put itself in the position of a TNSP at the time that they were undertaking a particular project to determine if the project was undertaken efficiently. Previously, this process has been the subject of controversy when it has been applied to network businesses. For these reasons, the Commission has removed the arrangements for *ex post* reviews and instead focused more on improving *ex ante* incentives.[14]

Schedule S6A.2.3

In light of the AEMC's 2006 Rule Determination, the only remaining scope for regulatory stranding under the Rules is in Schedule S6A.2.3(a). This provision allows for the value of a TNSP's assets dedicated to one or a small group of Transmission Network Users to be written down if the AER decides that the assets are no longer contributing to the provision of prescribed transmission services.

However, S6A.2.3(a) does not justify the creation of a new regulatory regime for SENEs for several reasons:

- First, the stated policy rationale for S6A.2.3(a) was to create incentives for TNSPs to manage the risk of large **load** customers 'critical to the commercial viability of the network' disconnecting and leaving the TNSP financially short, rather than to encourage TNSPs to make efficient transmission investment decisions.[15] Given that generators do not currently pay shared transmission network charges, this rationale was and remains inapplicable to shared transmission assets serving generators. If necessary, S6A.2.3(a) could be modified to clarify that it is not intended to apply in circumstances where the relevant Transmission Network User(s) are generators.

- Second, S6A.2.3(a) is unlikely to apply to most network extensions to areas of new renewable generation investment. This is because even if such extensions turn out to be under-utilised due to the non-arrival of some of the predicted new generation, such extensions are likely to continue to make some contribution to the provision of prescribed transmission services. As long as they do, such assets would not fall within the scope of S6A.2.3(a).

- Third, even if generator-serving network extensions are found to make no contribution to the provision of prescribed transmission services – and hence are at risk of regulatory stranding – a better of way of addressing this issue

14 p.98.

15 See AEMC, *Draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006, Draft Rule Determination*, 26 July 2006, p.70.

would be under S6A.2.3(b). This Rule provides for the AER to agree to a TNSP receiving an addition to its regulated return if it has assets that are at risk of optimisation despite the TNSP's prudent efforts to manage that risk. This would strengthen the incentives of the TNSP to make accurate forecasts of future generation investment in a RIT-T process. This is preferable to forcing customers to underwrite a risk that they have no information about or means of hedging.

Neither the MCE Rule change request nor the SENE Consultation Paper raises clause S6A.2.3 or otherwise engages with these issues. In our view, it would be preferable to consider the discussion above in more detail, rather than to pursue a new SENE-specific framework.

3 Flaws in the SENE proposal

3.1 Assessment framework

This section assesses the SENE concept as presented in the MCE Rule change request and the SENE Consultation Paper against the national electricity objective in section 7 of the National Electricity Law (NEL). Section 7 states:

> The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

The Rule-making test in section 88 of the NEL requires that the AEMC may only make a Rule if it is satisfied that the Rule will or is likely to contribute to the achievement of the national electricity objective.

The AEMC has stated that the national electricity objective incorporates:

- economic efficiency across the dimensions of:
  - productive efficiency – least cost operation of the power system
  - allocative efficiency – production and consumption decisions are based on opportunity costs
  - dynamic efficiency – productive and allocative efficiency over time
- good regulatory practice incorporating:
  - stability and predictability – to enable participants to plan and make long term decisions
  - transparency – to retain confidence in the regulatory arrangements.

The AEMC noted that "these qualities will help ensure that the arrangements will benefit consumers in the long run".[16]

The AEMC also stated that while distributional outcomes are not directly relevant to meeting the national electricity objective, distributional outcomes have relevance in so far as they may negatively influence the stability and integrity of the regulatory arrangements.[17]

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16 AEMC, *Rule Determination, National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22*, 21 December 2006, pp.10-11.

17 *Ibid.*, p.11.

3.2 No economic efficiency test

Apart from being unnecessary, the key flaw in the SENE concept as presented in the MCE Rule change request and the SENE Consultation Paper is the lack of a clear economic efficiency criterion that needs to be met for investment to proceed. Without such a test, there is a real risk that SENE investments will expose electricity consumers to the costs of investments that do not promote their long term interests, as required by the national electricity objective.

3.2.1 MCE Rule change request

The MCE Rule change request notes that an important element of the SENE concept "is a mechanism that minimises the risk to customers from SENE assets being under-utilised by generators".[18] The Rule change request highlights key features of the proposed arrangements designed to minimise this risk to consumers. These features include:

- A requirement for AEMO to identify possible geographic zones where network extensions could provide substantial scale economies.
- A requirement for a 'high-level assessment' by network businesses of credible SENE options and publication of these options, taking account of shared benefits and other implications for the shared network.
- A recommendation for network businesses to apply the RIT-T where they believe SENE assets would deliver possible benefits to the shared network
- A requirement for the AER to assess the generation forecasts and assumptions within each SENE proposal taking account of stakeholder submissions.
- A requirement for the AEMC to review the SENE arrangements after five years.

The Rule change request goes on to emphasise the importance of a SENE proposal embodying a robust forecast of future generation connection requirements. To this purpose, the MCE proposes that both AEMO and the relevant network business have a role in planning SENEs.

The Rule change request focuses on three elements of the proposed SENE framework directed towards minimising risks to customers:

- A requirement that at least one generator agrees to connect to a SENE before a SENE can proceed and an assessment about whether future

[18] p.2.

generators will also find it privately beneficial to enter ("this is the efficiency test that applies to SENEs").

- A requirement for AEMO to make an assessment of the NSP's generation forecast, taking account of stakeholder comments.
- An option for the AER to disallow the project if it considers that the generation forecast or cost estimates are not sufficiently robust.[19]

However, none of these elements imposes a requirement that the proposed SENE is likely to maximise net benefits to the market compared to a range of alternatives (which is the assessment criterion under the RIT-T). It is quite possible for forecasts of new generation connections to a SENE and estimates of SENE costs to be accurate but for the SENE to not be the most net beneficial option available under a range of reasonable future scenarios. This point is expanded below in relation to the AEMC's SENE Consultation Paper.

3.2.2 SENE Consultation Paper

Assessment framework

The assessment framework in section 5 of the SENE Consultation Paper refers to the need for efficient investment in electricity services, particularly connection assets. However, it does not mention the need for a SENE investment to satisfy any form of cost-benefit test to ensure it is *ex ante* net beneficial. Rather, the paper emphasises vaguer qualitative criteria such as:

- Generators are able to connect in a timely manner.
- Generators face cost-reflective locational signals.
- Investment in network assets is efficient in respect of size, location and timing.

We believe introducing these criteria would be a retrograde step and create inconsistencies within the regulatory framework. This raises the possibility of 'regime shopping' between the RIT-T and any possible new SENE framework.

Issues for consultation

In section 6 of the SENE Consultation Paper, the AEMC acknowledges that despite the strategic role of AEMO in identifying appropriate SENE zones, NSPs and generators may have some incentive to over-size SENEs. The costs of such over-sizing would be borne by electricity consumers through higher

19 MCE Rule change request, p.5.

network charges. The AEMC comments that the checks in the MCE Rule change request noted above should reduce these risks to consumers. However, consumers would continue to face the risks of new generation not appearing as forecast due to changes in government regulation or market conditions more generally.

The AEMC then raises the question of whether consumers are best-placed to manage the risks of uncertain generation forecasts when generators and NSPs may have better access to information about, respectively, new generation investment locations and network extension options.

The SENE Consultation Paper raises the option of "*a more explicit* economic efficiency test to potential network extensions" (emphasis added) as a means of managing risks to consumers. The paper explains that:

> Under the proposed framework, the test of the efficiency of the SENE undertaken by the AER is based on an assessment of reasonableness. However, assessing whether a proposal is "reasonable" may be interpreted broadly.

The reference to "reasonable" reflects the wording in 5.5A.8(c) of the draft Rule as set out in Appendix A to the SENE Consultation Paper. This Rule enables the AER to make a determination rejecting a SENE connection offer if it finds that, *inter alia*, the NSP's assessment of any of the following variables is not reasonable:

- Forecast generation profile.
- Design option for the SENE.
- Required SENE expenditure.
- Economic life of the SENE.

If the AER does not make a determination within 30 business days, the SENE connection offer is deemed to be approved.

Crucially, draft Rule 5.5A.8(c) does not enable the AER to reject a proposed SENE on the grounds that the proposed investment does not maximise net market benefits. Indeed, there appear to be no grounds for rejecting a SENE that yields net *costs* to the market as a whole. Draft Rule 5.5A.1(d)(3) confirms that SENEs are not subject to the RIT-T. We note, however, that there could still be debates about whether a given transmission investment is or is not a SENE and consequently inefficient 'regime shopping' between the RIT-T and SENE sets of regulatory arrangements.

Therefore, the draft Rule leaves open the potential for customers to underwrite the costs of SENE investments that could yield net costs to the market or are dominated by superior options. It is difficult to see how this meets the Rule-making test in section 88 of the NEL.

3.3 Compensation to constrained-off generators

The SENE Consultation Paper proposes a form of firm financial access for new connecting generators that contribute towards the costs of a SENE. Under the draft Rule, generators would be required to negotiate an agreed power transfer capability with the NSP as part of their connection agreements. If a generator is unable to access its agreed capacity due to a constraint on the SENE, the generator will be entitled to compensation. This compensation will be funded by any subsequent SENE-connecting generator to the extent it generates in excess of its agreed power transfer capability and constrains-off the original SENE-connected generator. The level of compensation is intended to reflect the constrained-off generator's foregone operating profit. Draft Rule 5.5A.14 reflects these arrangements.

While a form of financial firm transmission rights could be a valuable addition to the NEM design, we question whether the piecemeal approach embodied in the SENE proposal is the appropriate means to achieve this. A better approach would involve a comprehensive review of congestion management and transmission pricing arrangements in the NEM.

Moreover, it is likely that at least for several years after a SENE is commissioned, no network constraints on the SENE will emerge. SENE constraints will only arise where the peak capacity of new generator connections exceeds the transfer capability of the SENE. During this initial period, it is far more likely that SENE-connected generators will be constrained-off due to constraints downstream of the SENE, which will not be hedged by their rights to compensation for SENE constraints. This reinforces the point above that formulating meaningful financial transmission rights requires a broader-ranging approach than encompassed in the SENE Consultation Paper.

In relation to the specifics of the proposed compensation arrangements, one important element provided for in the draft Rule is the trigger for compensation. Compensation is only paid where a SENE-connected generator is constrained-off due to a constraint on the SENE (rather than further downstream on the shared network). The AEMC should consult with AEMO to ensure that it will be practicably able to isolate the location of constraints in this manner.

3.4 Logistical complications created by SENEs

The introduction of the SENE concept as a new form of network investment creates a number of logistical problems that are not present under the existing transmission regulatory arrangements in the Rules. Some of these types of problems are raised in sections 6.1.2 and 6.2.2 of the SENE Consultation Paper.

3.4.1 Logistical problems raised in the SENE Consultation Paper

Section 6.1.2 of the SENE Consultation Paper deals with the possibility that SENEs may emerge with different configurations to the 'hub and spoke' model anticipated to date. The paper acknowledges that SENE charging arrangements could become extremely complicated when different connecting generators utilise different proportions of a SENE asset.

Section 6.2.2 of the SENE Consultation Paper raises the issue of if and when SENE assets should 'convert' to regulated shared network assets. A key trigger for such a conversion could be the connection of a load customer to the SENE. Another trigger could be the formation of a network loop involving a SENE that resulted in various loop flows through the network. In these circumstances, constraints may form on SENEs due to the dispatch of generators not connected to the SENE. This would reduce the firmness of a connected generator's financial rights to SENE capacity.

In our view, any network regulatory regime that encompasses scope for different forms of regulation to apply to different assets or services at different times will raise uncertainty, and therefore make investment at the margin more difficult. The existing regime (see below) is not immune from these problems when, for example, the nature of a transmission asset's usage changes over time. However, the more types or forms of regulation, the more frequent and complex such boundary issues are likely to be.

The next two sub-sections explain how the issues raised by the SENE Consultation Paper in sections:

- 6.1.2 – Varying levels of utilisation of network extensions
- 6.2.2 – Changing functions of network assets

are avoided or addressed under the existing Rules.

To see why this is the case, it is first necessary to consider how transmission costs are allocated under the existing arrangements.

3.4.2 Cost allocation under the existing Rules

Under the present Rules, a TNSP is required to allocate the cost of any given asset to the various transmission services to which that asset is 'directly attributable' (ie: used, or required, to provide).[20] TNSPs' revenues from the

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20 See Rules 6A.19.2, 6A.22.3, 6A.22.4 and 6A.25.2. See also AEMC, *Rule Determination, National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22*, 21 December 2006, pp.33-35.

provision of prescribed transmission services are capped while the arrangements for negotiated transmission services are more light-handed.[21] The scope of negotiated services includes new connection services, which in turn includes entry services provided to generators. Entry service is defined to include a service provided to a generator, or group of generators, at a single connection point. A connection point under the Rules is itself no more than an 'agreed point of supply'.[22]

This means that chapter 6A of the Rules allows TNSPs to recover the costs of transmission investments from customers through prescribed transmission use of system (TUoS) charges, regardless of the location or technical characteristics of the investment, so long as such investment is not on the participant's side of its connection point. The key question is whether the asset in question is 'directly attributable' to the provision of:

- prescribed services – whether the asset is required to meet reliability criteria or provide system-wide benefits; or
- negotiated services – including assets requested by a particular network user that do not provide reliability or system-wide benefits.

So long as an investment helps satisfy mandatory reliability standards or provides system-wide benefits, it can be regarded as providing prescribed transmission services. In our view, any investment that satisfies the regulatory test/RIT-T should be regarded as providing system-wide benefits. Therefore, the costs of such investments should be allocated to the provision of prescribed transmission services and accordingly recoverable by the TNSP through its charges to customers for prescribed transmission services.

Conversely, chapter 6A requires the costs of assets that do not provide prescribed transmission services to be recovered through prices for negotiated services, even if the relevant asset has the technical characteristics of a part of the 'shared' network.

Overall, the prescribed/negotiated regime creates a fluid line between assets included and excluded from a TNSP's RAB, with this line effectively drawn on the basis of RIT-T assessments and participants' agreed connection points.[23] This allows the current regime to handle the issues raised in the SENE Consultation Paper relatively easily.

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21 Compare Part C of chapter 6A of the Rules (for prescribed transmission services) with Part D (for negotiated transmission services).

22 All transmission service definitions are contained in chapter 10 of the Rules.

23 Presumably, most participants would not object to network extensions that serve them to be classified as providing prescribed transmission services and hence for the costs of those assets to be recovered from prescribed transmission charges.

3.4.3 Avoidance of SENE issues under the existing Rules

Varying levels of exploitation of network extensions

This sub-section explains how the existing Rules deal with the issues raised in section 6.1.2 of the SENE Consultation Paper.

As noted above, under the existing Rules, network extensions that satisfy the regulatory test/RIT-T are 'directly attributable' to the provision of prescribed transmission services. Therefore, the costs of these assets can be recovered through prescribed transmission charges – principally, prescribed TUoS charges.

If network extensions do not satisfy the RIT-T or are not assessed under the RIT-T, then the decision to invest is left in the hands of the intending connecting generators. They are free to invest in such network extensions if they perceive the benefits to exceed the costs. If economies of scale in network infrastructure are available and there are multiple intending connecting parties, the parties may choose to share the costs in some manner. There are no barriers in the Rules to intending generators negotiating cost-sharing arrangements. Further, the TNSP is able to facilitate such negotiations[24] and under the Rules is free to set up its own guidelines for how costs would be allocated in the event that a party invests first and later parties want to 'piggy back' on the initial investment. For example, VENCorp has long had a set of Connection Augmentation Guidelines that clearly explain how multiple shared connections will be handled, although these guidelines do not cover the allocation of network augmentations to increase power transfer capability.[25]

Therefore, we consider that the existing Rules provide adequate scope for negotiations and guidelines to deal with the types of cases raised in section 6.1.2 of the SENE Consultation Paper. In our view, there is no benefit or need for the Rules to 'hardwire' or otherwise prescribe such arrangements beyond the existing high-level principles set out in Part D of chapter 6A of the Rules.

Changing function of network assets

We consider that the existing Rules also provide a sensible basis for dealing with the types of issues raised in section 6.2.2 of the SENE Consultation Paper. To the extent that the usage of an asset changes over time, the AEMC's final Rule Determination on transmission pricing specifically made clear that the costs of that asset should be reallocated to different services.[26] Therefore, the connection

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24 Particularly since the Grid Australia-initiated Rule change regarding NSP confidentiality obligations.

25 AEMO, *Victorian Electricity Network Connection Augmentation Guidelines*, March 2007, Issue No.2 (VENCorp Guidelines), available here, pp.27-30.

26 AEMC, *Rule Determination, National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22*, 21 December 2006, pp.33-35.

of a load to a network extension originally intended to serve generators could lead to part of the costs of that extension being reallocated from the provision of negotiated entry services to the provision of prescribed customer TUoS services.

Having said that, we accept that the framework for dealing with changing network usage under the existing Rules raises difficulties for the allocation of long-term financial rights to generators that underwrite funded augmentations. This is an area that the SENE proposal seeks to develop through the compensation arrangements discussed above. However, as noted above, we consider that if financial transmission rights are to be developed and made available in the NEM, this should occur through a holistic review of congestion management and transmission pricing arrangements rather than in a piecemeal fashion isolated to SENE-type investments. After all, the compensation rights raised in the SENE Consultation Paper are only effective where congestion arises on the SENE asset itself. The rights to compensation have no application where congestion arises downstream of the SENE on the regulated shared network or due to the dispatch of generators not connected to the SENE.

4 Experience from the gas industry

This section briefly considers the regulatory treatment of network extensions in the Australian gas industry. The gas industry has been selected as a comparator for electricity due to the large number of greenfields pipeline projects and expansions that routinely occur in the industry. Such types of investments are less common in certain other industries such as rail and telecommunications. However, many of the lessons from the gas industry – particularly from the emerging LNG export industry – are applicable to other sectors such as rail for iron ore and coal transportation.

4.1 Risk allocation and greenfields investments

Large-scale greenfields gas pipeline investments, such as a pipeline from a gas basin to a load centre, are generally underwritten by long-term take-or-pay contracts between:

- a gas producer intending to develop a site and construct a pipeline and
- customer(s) who wish to take delivery of the gas.

Such contracts necessarily 'lock in' parties for an extended period of time in order to provide the necessary certainty required to underwrite lumpy pipeline investments. However, there is no economic efficiency reason for such contracts to allocate the commercial risk of the pipeline investment to end-use customers.

Such risk-shifting is even less likely for the types of greenfields investments that have recently been contemplated in the LNG export industry.

4.2 Queensland's LNG industry

Over the last few years there has been increasing interest in developing Queensland's Coal Seam Gas (CSG) resources for LNG export. Numerous proposals for LNG projects have been announced, looking to utilise gas sourced from CSG reserves predominately in the Surat Basin and exporting processed LNG from Curtis Island off Gladstone. Examples include:

- Arrow Energy-Shell consortium[27]
- Queensland Gas Company (QGC/BG Group)[28]
- Santos-PETRONAS consortium[29]

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27 See here and here for project details.

28 See here for project details.

- Origin-ConocoPhillips consortium.[30]

The concentration of a large number of producers looking to build essentially identical assets (pipelines from the Surat basin and surrounds to Gladstone) provides an interesting analogy to the situation that the SENE concept is designed to address.

Appropriate scale of assets

In its recent final recommendation to the Minister regarding QGC's application for a greenfields pipeline access exemption, the National Competition Council (NCC) raised the prospect that QGC's proposed pipeline may not be of socially optimal size: [31]

> The existence elsewhere of pipelines of larger dimension than the QCLNG Pipeline raises the question of whether a single larger dimension pipeline (with compression and limited looping) may be a more efficient means of providing pipeline services sufficient to accommodate foreseeable demand of 5000 TJ/day.

In making its recommendation regarding an access exemption, the NCC must consider whether four 'pipeline coverage criteria' are likely to be met. In instances where at least once coverage criterion is not met, the NCC is free to recommend an access exemption to the relevant Minister. Criterion (b) considers the scale of the proposed pipeline: [32]

> (b) that it would be uneconomic for anyone to develop another pipeline to provide the pipeline services provided by means of the pipeline.

In relation to QGC's access exemption, the NCC interpreted criterion (b) broadly as referring to any pipeline capable of providing the services provided by the applicant's pipeline:[33]

> The Council considers that in the context of an application for a no coverage determination, having regard to the National Gas Objective, it should adopt a broader view of criterion (b) than that which might appropriately drive an applicant's commercial decisions. On this basis the Council is satisfied that criterion (b) is met.

The NCC's decision implies that it considered it would be preferable (from an overall welfare perspective) for a single larger pipeline to be developed rather than an additional pipeline of equivalent size to QGC's proposed pipeline. In

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29 See here for project details.

30 See here and here for project details.

31 See the NCC's Final Recommendation to the Minister, pp.29-30.

32 See pipeline coverage criterion (b) of Part 15 of the National Gas Law.

33 NCC, Final Recommendation, p.30.

other words, QGC's gas pipeline was not 'right-sized' from an overall societal perspective.

This discussion has parallels with the contention made by the MCE in justifying its SENE proposal:

> When connections cannot be coordinated or built to an efficient scale, there is a risk of inefficient duplication in network assets...[34]

Despite the NCC's view that inefficient duplication of pipeline infrastructure may occur between the Surat basin and Gladstone, to Frontier's knowledge no formal centralised mechanism (current or planned) exists to efficiently scale potential pipeline(s) in this region. The size, type and location of these pipelines will presumably be left to each individual producer to decide.

To the extent it makes commercial sense, one would expect to see the emergence of some form of investment coordination between parties going forward – indeed rumours of both consolidation in the industry and possible infrastructure sharing arrangements attest to this.

Further, the risks of CSG pipeline developments will tend to remain with producers. This is consistent with the largely price-taking nature of the LNG export industry in Australia – as the price for LNG is set internationally on global markets, individual project risks cannot be sheeted to consumers. This reasoning is also like to apply to the risks of rail infrastructure used for transporting coal and iron ore from greenfields sources of supply.

4.3 Dampier Bunbury Natural Gas Pipeline

Arrangements used to fund augmentations of the Dampier Bunbury Natural Gas Pipeline (DBNGP) in Western Australia provide additional support for the above contention that it is not common practice in the Australian gas industry for the risk of pipeline augmentations to be borne solely by end users as a matter of course.

The DBNGP runs approximately 1,600 km from the Burrup Peninsula near Dampier to Bunbury in the state's south-west. The Dampier to Kwinana section of the DBNGP was commissioned in 1984. Initial construction of the pipeline was approximately fifty percent underwritten by one of the pipeline's major customers, Alcoa, who in 1983 signed a 20 year gas supply contract with the (then) State Energy Commission of Western Australia for half the pipeline's

34 MCE rule change proposal, p.4.

capacity.[35] Subsequent extensions and augmentations have been underwritten by sales contracts sold on the incremental capacity created by these upgrades.

The use of sales contracts to fund pipeline augmentations and extensions is common practice on both the DBNGP and the Goldfields Gas Pipeline (GGP):

> Both the DBNGP and the GGP have indicated they will not expand capacity without a 15-year commitment of a 'critical amount' from a customer willing to underwrite the expansion. [36]

and

> All firm capacity in the DBNGP pipeline is currently committed to shippers and the owners of the DBNGP will not expand the pipelines firm capacity unless it is underwritten via a long term ship or pay contract. [37]

What this suggests is that bilateral contracts between pipeline owners/operators and users of the pipeline's services are used to provide the long-term demand (and hence cash flow) certainty necessary to underwrite large augmentations and/or extensions. A formal centralised mechanism to 'ex post efficiently' scale and/or time these augmentations, and shift the associated risk of such augmentations to end-users, does not exist.

This point is perhaps best illustrated by the views of Mark Cooper, General Manager (Commercial) of Dampier Bunbury Pipeline (DBP), owners/operators of the DBNGP, expressed in a 2007 interview regarding extending the DBNGP further south to Albany:

> A number of the loads identified in 2000 have now gone, but new ones have also appeared – but it is still only about half viable [in terms of the load necessary to make the pipeline viable]. DBP is ready to extend the DBNGP to Albany if someone – the State or Federal Government or local authorities – who is able to manage the growth risk is willing to underwrite the non-commercial half (or so) of the pipeline... [38]

What this suggests is that the DBNGP will be extended south to Albany if and when demand willing to sign long-term supply agreements reaches a level sufficient to justify the extension. Under the current arrangements, prematurely extending the pipeline (and/or scaling the extension over and above that justified by contracted capacity) would not occur. The risk associated with such an

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35 Submission by Alcoa to the Productivity Commission's *Gas Access Regime Inquiry*, September 2003, p.4, available here.

36 Chevron, submission to the Federal Government's *Energy White Paper*, May 2009, p.13, available here.

37 BHP Billiton, submission to the Office of Energy's *Broadening the Gas Specification on Pipeline in Western Australia: Issues Paper*, November 2008, p.25, available here.

38 See here: http://pipeliner.com.au/news/dbp_building_was_future/040038/

augmentation is thus not borne by all end-users. Rather, it is managed by way of bilateral contracts between the pipeline owner and those customers willing to sign long-term supply agreements.

5 Incremental changes

Sections 2 and 3 of this report explain why Frontier considers that the SENE proposal is both unnecessary and flawed. We are of the view that the existing regulatory regime for transmission (incorporating the RIT-T) is broadly appropriate for promoting efficient investment in new network extensions to remote areas or otherwise. One relatively minor change that could be made to the existing Rules is to clarify that S6A.2.3(a) is not to apply in circumstances where the relevant transmission network user(s) are generators. This would remove the last vestige of regulatory stranding risk faced by TNSPs in respect of SENE-type investments.

Nevertheless, if the AEMC believes that the SENE concept has sufficient merit to pursue further, we would suggest a number of incremental changes to the proposed regime set out in the SENE Consultation Paper.

Briefly, our suggested incremental changes are as follows:

- Impose an obligation for a NSP to demonstrate that a SENE satisfies a robust cost-benefit test along the lines of the regulatory test/RIT-T.
- Empower the AER to reject a SENE investment if the AER determines that the SENE does not satisfy the cost-benefit test.
- Provide for refunds to SENE-connecting generators if the usage of SENE assets changes such that SENEs provide exit or TUoS services to loads. This would require NSPs to apply similar cost allocation processes as currently in place in chapter 6A of the Rules.

Appendix A sets out more detailed policy and drafting comments on the draft Rule attached to the SENE Consultation Paper.

Appendix A – Detailed policy and drafting comments on proposed SENE draft Rule

This appendix briefly outlines Frontier's more detailed comments on the drafting of the proposed SENE draft Rule. Some of these comments raise policy issues for further consideration.

No obligation for DNSP customers to pay shortfalls

The MCE Rule change request[39] and the SENE Consultation Paper[40] both envisage that electricity consumers would fund any shortfall (and receive any surplus) in SENE costs not recovered through charges to connecting generators. This is confirmed in the SENE draft Rule (5.5A.1(c) and (d)(5) and 5.5A.12(a)[41]).

However, the draft Rule does not impose any obligation on DNSPs to pay unrecovered SENE costs. Draft Rule 5.5A.1(c) describes the provision of a SENE as a negotiated transmission or distribution service. But even the revised definition of negotiated transmission service in the draft Rule does not incorporate use of system services provided to transmission network users pursuant to SENEs.[42]

Moreover, most DNSPs do not receive or procure negotiated transmission services from TNSPs. In particular, transmission connection services provided by a TNSP to a DNSP fall within part (c) of the definition of prescribed transmission service in chapter 10 of the Rules. The terms of draft Rule 5.5A.15 does not change this situation. Furthermore, it is difficult to see why DNSPs would ever seek to procure negotiated transmission services from TNSPs given that DNSPs typically supply a large number of end-use consumers.

For all these reasons, the draft Rule does not appear to impose an obligation on DNSPs to pay SENE-related charges to TNSPs. This raises doubts about the ability of the draft Rule to achieve the policy intention of making consumers fund shortfalls in the recovery of SENE costs from generators.

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39 p.3.

40 p.7.

41 Note – there appear to be several cross-referencing errors in draft Rule 5.5A.12(a) and 5.5A.13(i) and (j).

42 The revised definition of negotiated transmission service only refers to use of system services provided to transmission network users in relation to augmentations or extensions described in rule 5.4A.

No requirement for internal consistency of generation forecasts

Under draft Rule 5.5A.5(c)(1), a NSP is required to publish a SENE planning report that sets out the NSP's best estimate of the forecast generation profile for a SENE. The report must also set out the NSP's calculation of SENE charges payable by connecting generators (draft Rule 5.5A(c)(4)). However, while Rule 5.5A(c)(4) explicitly requires that the proposed SENE charges must take account of the forecast generation profile, there is no clear requirement for the generation forecasts to be consistent with the proposed level of SENE charges. Clearly, the amount of generation likely to connect to a particular SENE will be influenced by the level of SENE charges. This raises the possibility that the forecast generation profile is developed 'naively' of SENE charges and thereby overstates the likely quantity of new generation connections.

Furthermore, while the provisions governing the review of the NSP's generation forecasts by AEMO (draft Rule 5.5A.7) and the AER (draft Rule 5.5A.8) require the forecast generation profile to be reasonable, neither provision requires that the forecast generation profile is consistent with the level of proposed SENE charges.

Limited applicability of AER SENE planning guidelines

Draft Rule 5.5A.5(i)-(j) requires the AER to develop SENE planning guidelines to provide guidance and worked examples as to a range of variables relevant to the formulation of a SENE planning report and SENE connection offer. However, the only application of these guidelines is in draft Rule 5.5A.5(d), which requires the NSP to 'have regard to' a range of matters, including the guidelines, when preparing a SENE planning report. This is a relatively loose procedural obligation. There is no requirement for the NSP to prepare its report in compliance with the guidelines.

Appendix A – Detailed policy and drafting comments on proposed SENE draft Rule

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