RULE CHANGE

Australian Energy Market Commission

OPTIONS PAPER

National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010

Rule Proponent(s)

Ministerial Council on Energy

Commissioners

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30 September 2010

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Reference: ERC0100

Citation

AEMC 2010, Scale Efficient Network Extensions, Options Paper, 30 September 2010 , Sydney.

About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005 to be the rule maker for national energy markets. The AEMC is currently responsible for rules and providing advice to the MCE on matters relevant to the national energy markets. We are an independent, national body. Our key responsibilities are to consider rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council as requested, or on AEMC initiative.

Executive Summary

The arrangements for connecting new generation to the national grid are likely to be tested over the next few years as the patterns of generation investment are expected to change.

Concern regarding the impacts of climate change have lead the Government to take steps to encourage changes in behaviour so as to reduce carbon emissions. This is particularly relevant in the highly carbon-intensive National Electricity Market (NEM), where coal-fired generation accounts for around 85 per cent of generation output. As a result, an increase in lower carbon-intensive generation seeking connection to the national grid is occurring and is likely to continue over the next decade and beyond.

The frameworks that govern the terms and conditions under which generation can access the grid must be robust to the challenges that are likely to arise from the increased number, changing technologies and different locations of generation connections. The frameworks must allow these changes to occur while continuing to promote efficient outcomes in the NEM in the long term interest of consumers.

Achieving coordinated connection outcomes is challenging

Historically, the scale of investment in generation has matched the scale of the transmission or distribution investment that is required to facilitate connection. Networks have developed to meet the requirements of these generators.

The characteristics of the generation that is likely to connect over the next decade differ in a number of respects, such as:

- some of the lowest cost sources of generation are located remote from the existing networks; and
- much of the new generation that is likely to seek connection is relatively small compared to the "lumpy" network investment required to connect it.

This implies that there are likely to be efficiencies from coordinating such connections, particularly where new generation clusters around an energy source such as wind or gas. Connecting generators in a way that will minimise expected total system costs will require investment that is more forward looking.

However, achieving coordinated connections is likely to prove challenging under the existing frameworks. This is because no entity currently has an incentive to underwrite the risks of building additional network capacity in anticipation of future generation. The nature of the broader framework does not encourage or reward speculative building of transmission assets, either by Network Service Providers (NSPs) or generators. Uncertainty regarding the likelihood of generator entry and a reluctance on the part of generators to tie their projects to the time frames of their competitors further hinders efficient connection outcomes.

This Rule change request

In response to these challenges, the Ministerial Council on Energy (MCE) submitted a Rule change request to the Australian Energy Market Commission (AEMC or the Commission). The proposed Rule seeks to implement a new framework for Scale Efficient Network Extensions (SENEs) that would allow the efficient coordination of clusters of new generation that are expected to seek to connect in proximate locations over time.

The Rule change request stemmed from the AEMC's previous Review of Energy Market Frameworks in light of Climate Change Policies. During that review, stakeholders generally considered these anticipated challenges warranted changes to the National Electricity Rules (NER or the Rules). The high level policy developed during the course of that review was generally considered appropriate.

However, following the development of the more detailed proposed Rule, there appears to have been a shift in support away from the proposed Rule in its current form. While there is still some support for change, this has been tempered by the complex nature of the proposed Rule and the implementation difficulties that it poses. In particular, some stakeholders consider:

- the proposed Rule requires customers to bear significant risks that they are not best placed to manage;
- competitive neutrality between generators that connect to the SENE and those that connect directly to the network has been questioned; and
- certain characteristics of SENEs do not fit naturally into the existing framework which creates an additional layer of complexity, such as the nature of the service that the SENE provides and compensation arrangements where generators are constrained off the SENE.

In recognition of the high level of interest in this proposed Rule change, the AEMC considers it appropriate to test a number of alternative solutions with stakeholders prior to making a draft decision on whether to make a Rule and, if so, whether to make the Rule as proposed or a more preferable Rule.

Interaction between the Rules and SENEs

The framework governing connections to the network was developed during a different period in the NEM when a single, relatively large scale generator typically connected to the network using a dedicated asset. This paradigm is now changing as we seek to allow more efficient outcomes via shared connection assets. However, the characteristics of SENEs do not naturally fit into the existing framework of the Rules.

For example, SENEs (as originally proposed) are intended to be extensions to a network for the purposes of connection which, under the current Rules, are typically funded by the network user (in this case generators). However, because the purpose behind SENEs is to build capacity in advance of generation, customers are required to fund part of the asset until the forecast generation materialises to allow network investments to be forward looking. Further, the Rules do not envisage an asset that is funded by customers subsequently being funded by generators. This introduces complexity for cost recovery arrangements.

This tension between SENEs and the existing framework is exacerbated by differences between the original intention behind aspects of the Rules, what the Rules say and how they may be interpreted, what is done in practice, and now what outcomes we would like the Rules to facilitate. Ideally, the Rules would be robust to all current and future patterns of generation so that changes can be accommodated without the need for new, specific provisions in the Rules.

Assessing the proposed options

We have developed an assessment framework to evaluate both the proposed Rule change and alternative options that may result in the AEMC making a more preferable Rule to ensure that any framework changes are consistent with promoting the national electricity objective (NEO).

Applying the assessment criteria is likely to require trade-offs between competing objectives. For example, SENEs are intended to capture network scale efficiencies associated with coordinated connections and ensure generators are able to connect in a timely fashion. However, allowing pre-building of transmission infrastructure to meet these objectives is costly and creates a risk of asset stranding where the forecast generation does not materialise.

Similarly, there may be a trade-off between the complexity of the Rule and the degree to which it is consistent with the existing frameworks. SENEs are a unique concept and therefore some aspects do not naturally fit within the existing arrangements as articulated in the Rules.

Five options to test

The AEMC is seeking comment on five possible options to address the issues raised in the SENEs Rule change proposal. The scope of this Rule change, and therefore the options that have been developed, extend to the arrangements for connecting generation to the shared network. The scope does not extend into changing the arrangements that govern the shared network. Where issues are identified in relation to the shared network, these will be addressed through alternative processes.

Options 1 and 2 are based on the existing proposed SENEs framework, with some revisions to strengthen the risk mitigation mechanisms and simplify the proposal. The key differences between these options and the proposed Rule change are:

- Option 1 introduces a cost threshold trigger such that the SENE will only be built once 25 per cent of the capital costs of the investment are underwritten by firm connection agreements with generators; and

- Option 2 also includes a cost threshold trigger, but further strengthens the risk mitigation measures through the explicit application of an economic test. In addition, the proposed framework is simplified by removing the regulated compensation arrangements, leaving these to be negotiated.

Option 3 is based on an approach put forward by Grid Australia. The Regulatory Investment Test for Transmission (RIT-T) is applied to incremental capacity above that required to connect a first generator (or group of generators). The first generator(s) would pay the stand alone costs of its connection to the network in the absence of a scale efficient connection. Subsequent connecting generators would contribute to the stand alone cost of the first generator(s). The cost of any incremental capacity justified by the RIT-T would be met by customers.

Option 4 is a variation on the Grid Australia approach with different cost recovery arrangements such that generators are expected to pay for the SENE over time, provided that generation materialises as forecast. Customers would continue to underwrite the risk of asset stranding.

Option 5 maintains the principle that generators should face the costs incurred in connecting them to the network. However, instead of recovering this as a negotiated service, a new type of prescribed service is introduced that is paid for by generators. Customers would still underwrite the cost of any spare capacity, but with a simplified charging framework.

Submissions to this Options Paper

This Options Paper is intended to test a number of potential solutions with stakeholders to assist the Commission in determining which will best address the identified gaps in the existing framework, consistent with the NEO.

In particular, the AEMC is seeking stakeholders' views on:

- which option best promotes the NEO, and why;
- whether there are other broad implementation issues associated with the options that have not been identified; and
- whether there are other options we should consider which may better address the issues identified by this Rule change and, if so, how they would better promote the NEO.

Contents

1 Introduction

1.1 The Rule change request

On 15 February 2010, the MCE submitted a Rule change request to the AEMC in relation to the introduction of a new framework to deal with the connection of clusters of new generation that are expected to seek to connect over time.

The purpose of the proposed arrangements for SENEs is to allow the efficient connection to the network of multiple generators over a period of time in proximate locations so as to minimise expected network costs.

1.2 Purpose of this Options Paper

The Commission considers that, for the purpose of this Rule change request, there is value in adding an extra step to the standard consultation process for Rule making. The decision to publish an Options Paper prior to making a draft Rule determination was informed by the following considerations:

1. the complex nature of the proposed Rule change;
2. divergent views expressed across the industry and within industry sectors; and
3. the emergence of possible alternative solutions.

Consultation to date indicates that there is a high level of interest amongst market participants regarding this Rule change request. The nature of responses has indicated some uncertainty as to whether the Rule as proposed is likely to satisfy the NEO.

As a consequence, the Commission has undertaken further analysis and considered a number of alternative solutions, including one put forward by Grid Australia.[1]

The purpose of the Options Paper is to test these potential solutions with stakeholders. This will assist the Commission in determining the best way to address the issues that this Rule change has identified and ensure that any changes to the existing frameworks are consistent with, and will contribute to, the achievement of the NEO.

1.3 The Rule change process and consultation to date

On 1 April 2010, the Commission published a notice under section 95 of the National Electricity Law (NEL) setting out its decision to commence the Rule change process for this Rule change request. The Commission decided to consider the proposed Rule under the standard Rule making process and not through the expedited process under section 96 of the NEL.

1 Grid Australia, Consultation Paper supplementary submission, 4 August 2010.

The notice was accompanied by an AEMC staff Consultation Paper that was prepared to facilitate public consultation on the Rule change proposal.[2] Twenty-eight submissions and two supplementary submissions[3] were received in response to the Consultation Paper.[4] An overview of the submissions is provided in section 2.3.

On 1 July and 19 August 2010, the Commission published notices under section 107 of the NEL extending the periods for publishing the draft and final Rule determinations for this Rule change request. The Commission considered that the proposed Rule change raises issues of sufficient complexity and difficulty such that an extension of time is necessary.

1.4 Remainder of this Rule change process

The remainder of the process set out in the NEL involves, at a minimum:

- publication of a draft Rule determination;
- an option for the Commission to hold a public hearing after the publication of the draft Rule determination;
- at least six weeks of public consultation on the draft Rule determination; and
- publication of the final Rule determination within six weeks of the close of public consultation on the draft Rule determination.

In addition to these steps, the Commission proposes to hold a public forum prior to submissions closing on this Options Paper. The forum will be held on 20 October 2010 in Adelaide. Further details and registration are available at www.aemc.gov.au.

Milestone	Timetable
Publication of Options Paper	30 September 2010
Public Forum	20 October 2010
Close of submissions	12 November 2010
Draft Rule determination	17 February 2011
Final Rule determination	12 May 2011

2 AEMC 2010, Consultation Paper, *National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010*, 1 April 2010.

3 EnergyAustralia and Grid Australia indicated in their initial submissions that they would be preparing case studies. These were received on 16 June and 4 August 2010, respectively.

4 These submissions are available on the AEMC's website at www.aemc.gov.au.

Stakeholders should also note that the Commission may propose to:

- Make a more preferable Rule in certain cases under section 91A of the NEL, where the Commission is satisfied that, having regard to the issues raised by the proposed Rule, the more preferable Rule will or is likely to better contribute to the achievement of the NEO than the proposed Rule.
- Make a more preferable Rule in view of the response to a draft Rule determination under section 102A of the NEL.

1.5 Structure of this Options Paper

The remainder of this Options Paper is structured as follows:

- section 2 sets out the background to the Rule change proposal;
- section 3 highlights the issues this Rule change is seeking to address;
- section 4 discusses the framework for assessing this Rule change request;
- section 5 sets out an overview of the existing connection arrangements and how they may or may not facilitate building connections that capture scale economies;
- section 6 discusses the range of design features to be considered in developing the SENEs framework;
- section 7 highlights the various implementation issues associated with those design features;
- section 8 defines a set of proposed alternative options and provides some commentary on those options, drawing on the assessment framework and implementation issues; and
- section 9 outlines the process for making submissions.

2 Background to this Rule change request

2.1 Review of the Energy Market Frameworks in light of Climate Change Policies

In August 2008, the MCE directed the AEMC to undertake a review of the existing energy market frameworks to assess the resilience of those frameworks to the expected changes in market behaviour likely to result from the planned introduction of the expanded Renewable Energy Target (RET) and the proposed Carbon Pollution Reduction Scheme (CPRS). The Terms of Reference asked the AEMC to review both electricity and gas markets across all jurisdictions and to provide detailed advice on the implementation of any changes required to those markets.

The Final Report of the Review of Energy Market Frameworks in light of Climate Change Policies (Final Report) was submitted by the AEMC to the MCE on 30 September 2009.[5] The Final Report concluded that the current energy market frameworks, if supported by a number of recommended changes, are capable of accommodating the impacts of the RET and CPRS. One of the key recommendations was the introduction of a mechanism, SENEs, to promote the efficient connection of clusters of new generation seeking to connect to the electricity network over a period of time.

During consultation prior to the Final Report, the majority of stakeholders supported the AEMC's conclusion that the existing connection frameworks are unlikely to promote efficient connection outcomes under future climate change policies, in particular the RET.[6] The majority of stakeholders also supported the draft recommendations set out in the 2nd Interim Report to the review[7], which formed the basis of the proposed Rule for SENEs.

The MCE supported the AEMC's findings and recommendations in its response to the Final Report.[8] In particular, the MCE endorsed the recommendation regarding the efficient connection of clusters of generation, noting that the proposed SENE framework would deliver benefits to the market by providing greater flexibility for the NEM to respond to the challenges posed by climate change policies. The MCE therefore requested that the AEMC progress the Rule change proposal, having regard to the contents of the MCE's response.

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5 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, Sydney. Available at www.aemc.gov.au.

6 Ibid. p.15.

7 Ibid. p.17.

8 MCE 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Response to Australian Energy Market Commission's Final Report*, December 2009.

2.2 Consultation Paper

On 1 April 2010, the AEMC published a staff Consultation Paper which set out the process for considering this Rule change request. The Consultation Paper noted the Commission's obligations to consider the Rule change request having regard to the NEO. As part of this assessment, the AEMC intended to assess whether efficient outcomes are more likely to arise under the proposed SENE framework compared to outcomes under the status quo. The paper also highlighted a number of complex issues that the AEMC considered would need to be analysed and addressed as part of the assessment of the proposed new framework.

A key point raised in the Consultation Paper was that any new framework that allowed capacity to be built in anticipation of future generation connections would need to ensure that consumers were appropriately protected from asset stranding risks, where expected generation does not materialise, or enters later than expected. While the proposed SENE framework contains a number of mechanisms for reducing risks to customers, the Consultation Paper proposed to explore alternative risk management mechanisms, including options that require generators to assume a greater proportion of the risk. The options raised included introducing an explicit economic efficiency test, giving NSPs incentives to efficiently size assets and a number of market-based options.

The Consultation Paper also considered a number of implementation issues that would need to be resolved for the scheme to be implemented. These included:

- ensuring the Rule would promote efficient network configuration outcomes that minimise the risks of asset stranding;
- ensuring capacity on the SENE would be efficiently allocated amongst generators, particularly once the SENE was fully subscribed; and
- considering the consequences of awarding firm financial rights to generators on the SENE where the SENE becomes difficult to distinguish from the shared network.

2.3 Summary of submissions

The high level of interest in the proposed Rule change was demonstrated by the twenty-eight submissions received from stakeholders in response to the staff Consultation Paper. There was no clear consensus in the responses, with a range of views being expressed, even within industry sectors.

Many stakeholders agreed that timely and efficient connection will be a challenge where the pattern of generation investment changes.[9] However, a number of

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9 Grid Australia, Consultation Paper submission, p.7; TRUenergy, Consultation Paper submission, p.2; Infigen Energy, Consultation Paper submission, p.1; Clean Energy Council, Consultation Paper submission, p.2; Geodynamics, Consultation Paper submission, p.3; Tasmanian DIER, Consultation Paper submission, p.2; SA Chamber of Mines and Energy, Consultation Paper submission, p.1; Origin Energy, Consultation Paper submission, p.3.

submissions also considered that significant analysis still needs to be undertaken to demonstrate that the SENEs proposal is an appropriate and proportional response to the issues it is trying to address.[10]

This suggests that while there appears still to be general support for the high level policy proposal, consistent with consultation during the Review of Energy Market Frameworks in light of Climate Change Policies, mechanisms to give effect to the policy are more contentious.

We note that some stakeholders disagree that the need for change has been demonstrated, arguing that existing frameworks are sufficiently robust.[11] For example, AGL noted that it did not consider that a market or regulatory failure had been revealed in the existing economic framework. It suggested that the SENE proposal should not be progressed until, among other things, the new Regulatory Investment Test for Transmission (RIT-T) has been given sufficient time to operate in the NEM.[12] LYMMCo was of a similar view.[13]

Some stakeholders are concerned that the proposed Rule requires customers to bear significant risks which they are not best placed to manage.[14] While many stakeholders consider that the inclusion of more checks and balances may help to mitigate some of the risks faced by consumers, several other stakeholders consider that additional checks and balances would still be insufficient to protect consumers. For example, Alinta Energy notes that mitigating customer risk "would require moving asset stranding on to the decision makers best able to manage risk – SENE generation proponents and TNSPs/DNSPs”. However, Alinta Energy recognises that this is, more broadly, "seen as being a significant problem with the current regime.”[15]

In addition, several stakeholders expressed concern that competitive neutrality between generators that connect to the SENE and those that connect directly to the network may be compromised by implementation of the proposed Rule change proposal.[16] For example, the MEU suggests that this proposal “gives more distant renewable generation a benefit which will not be enjoyed by renewable generation located nearer to the shared network.”[17]

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10 AER, Consultation Paper submission, p.3; Grid Australia, Consultation Paper submission, p.4; Macquarie Generation et al, Consultation Paper submission, p.2.

11 AGL, Consultation Paper submission, pp.3, 5; LYMMCO, Consultation Paper submission, p.12; Alinta Consultation Paper submission, pp.6-7.

12 AGL, Consultation Paper submission, pp.3,5.

13 LYMMCO, Consultation Paper submission, pp.11-12.

14 Alinta Energy, Consultation Paper submission, p.10; Energy Supply Association of Australia, Consultation Paper submission p.5; EnergyAustralia, Consultation Paper submission p.7; Tasmanian DIER, Consultation Paper submission, p.2; Energex, Consultation Paper submission, p.1; Macquarie Generation et al, Consultation Paper submission, p.3.

15 Alinta Energy, Consultation Paper submission, p.10.

16 LYMMCO, Consultation Paper submission, p.5; Major Energy Users, Consultation Paper submission, p.12; NGF, Consultation Paper submission, p.20.

17 Major Energy Users, Consultation Paper submission, p.12.

Further, a number of stakeholders consider that certain characteristics of SENEs do not fit naturally into the existing framework, for example, the nature of the service that the SENE provides and compensation arrangements where generators are constrained off the SENE.[18] These stakeholders are of the view that the proposed arrangements create a further layer of complexity into the Rules, which is not desirable. In its submission, Energex notes that "the proposed arrangements appear overly complex and their practical application may not deliver the efficiencies that are envisaged."[19]

Stakeholders also commented on specific aspects of the proposed Rule change. We have considered these views throughout this Options Paper, where relevant. The AEMC intends to respond to the more detailed comments once the broader framework has been determined.

Grid Australia and EnergyAustralia both submitted supplementary submissions with illustrative case studies. Grid Australia's case study considered two alternative SENE models, both of which incorporated the RIT-T.[20] EnergyAustralia's case study aimed to develop a scenario to reflect the circumstances that may be experienced by a distribution network.[21] For further information on these case studies, see the Grid Australia and EnergyAustralia supplementary submissions available at www.aemc.gov.au.

2.4 Interaction of this process with the Transmission Frameworks Review

On 20 April 2010, the MCE directed the AEMC to conduct a review of the arrangements for the provision and utilisation of electricity transmission services in the NEM, with a view to ensuring that the incentives for generation and network investment and operating decisions are effectively aligned to deliver efficient overall outcomes.

The Transmission Frameworks Review (TFR) will review the role of transmission in providing services to the competitive sectors of the NEM, through considering the following key areas together in a holistic manner:

- Transmission Investment;
- Network Operation;
- Network Charging, Access and Connection; and
- Management of Network Congestion.

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18 Energex, Consultation Paper submission, p.3; Grid Australia, Consultation Paper submission, p.10; SPAusNet, Consultation Paper submission, p.3; AER, Consultation Paper submission, p.1; EnergyAustralia, Consultation Paper submission, p.8; CitiPower/Powercor, Consultation Paper submission, p.1; Macquarie Generation et al, Consultation Paper submission, p.1.

19 Energex, Consultation Paper submission, p.3.

20 Grid Australia, Consultation Paper supplementary submission, 4 August 2010.

The Final Report for the TFR is to be submitted to the MCE by 30 November 2011.

The Commission notes that, during the course of this Rule change process, some issues may arise that also fall within the scope of the TFR. However, the Commission considers that many of the issues highlighted by SENEs are sufficiently separable. Therefore, the AEMC has decided to proceed with this Rule change request rather than combine the two processes. Notwithstanding this, the scope of the TFR will be a factor in considering the various options put forward. For example, one consideration in assessing the proposed options is their flexibility to accommodate any framework changes that might result from the TFR.

Broadly, the options proposed in this paper only consider the arrangements for connecting generators to the network: they do not extend to the arrangements governing the shared network itself. While we consider what implications SENEs may have for the shared network, any changes to the frameworks for access to, and augmentation of, the shared network will be considered under the auspices of the TFR.

21 EnergyAustralia, Consultation Paper supplementary submission, 16 June 2010.

3 Issues this Rule change is seeking to address

This purpose of this section is to set out the issues this Rule change seeks to address.

3.1 The purpose of this Rule change

The AEMC considers that this Rule change is intended to strengthen the connection framework to ensure that it can continue to meet customers' energy needs at an efficient cost, consistent with the NEO, in light of the changing patterns of generation that may result from future policy and technology developments.

The AEMC considers the objective is to allow the efficient connection of multiple generators with multiple owners in proximate areas over time and to charge generators an efficient price for that service. Achieving this objective will help to ensure that the Rules provide a robust framework to allow the goals of various government policies and programmes, such as the RET, to be achieved in an efficient manner.

The rationale behind this objective is set out in the remainder of this section and is further clarified in the context of the assessment framework outlined in section 4.

3.2 Policy drivers

The expanded RET and other policy initiatives directed at carbon reduction, including various proposals for a direct or indirect price on carbon, are intended to change behaviour and investment in Australia's energy markets. This is because electricity generation is currently highly carbon-intensive, with coal-fired generation accounting for around 85 per cent of generation output in the NEM.[22] In 2008, electricity generation accounted for around 37 percent of total emissions in Australia.[23]

Broadly, these policies and proposals aim to change the underlying economics of generation, by encouraging investment in new plant with lower carbon intensity than the bulk of existing generation.

However, there is significant uncertainty in the long term about the type and location of the large amount of generation investment that is required, including new base load plant. Market and regulatory frameworks will therefore need to accommodate a broad range of outcomes.

3.3 Patterns of generation investment are changing

Over the next decade, significant new investment in renewable generation capacity needs to be accommodated. Estimates suggest that the RET will stimulate

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22 AER 2009, *State of the Energy Market 2009*, p.55.

23 Department of Climate Change and Energy Efficiency 2010, Australian National Greenhouse Accounts, National Greenhouse Gas Inventory, May 2010, p.7.

approximately 8000 MW of new renewable plant by 2020.[24] It is currently anticipated that many of the new connections over the course of the next decade will be wind generators given the economics of available renewable generation technologies.[25] However, other types of technology may also enter the market as they become commercially viable, including geothermal, large scale solar and bioenergy. These new sources of generation will need to connect to existing transmission and distribution networks.

Historically, investment in electricity generation has been characterised by sizable instalments of generation capacity. The existing transmission networks have developed over time to meet the requirements of these investments, which have typically located close to coal sources, the dominant source of fuel to date.

Unlike generation from traditional sources of fuel, wind generation is characterised by smaller units of investment, often less than 100 MW. The most resource rich locations are often, but not always, located remote from the existing network. It is possible that new investment in wind generation by multiple parties will seek to cluster in these resource rich locations and are expected to connect at different times over a period of several years.

These views are supported by recent analysis undertaken by the Australia Energy Market Operator (AEMO)[26]and Electranet[27] in considering options for the efficient connection of new generators clustered in regions of Victoria and South Australia respectively. While both parties have been exploring how efficient connection could be facilitated under current frameworks, it is possible that additional tools will be required to allow further efficiencies in connection to be captured.

These challenges are likely to continue as new technologies become viable. For example, the Cooper Basin has been mooted as a potential area for generation investment once geothermal technology is commercialised.[28]

In addition to the potentially large number of applications NSPs will be required to process over a relatively short period of time, these characteristics of likely new entrant generators highlight a number of challenges for current frameworks to connect multiple generators to the network in a timely and efficient manner.

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24 MMA 2008 Treasury paper, Figure 3-6, p.39.

25 ROAM 2008 Market Impacts paper, pp.29-32.

26 AEMO has indicated that both Regional Victoria (Ballarat region) and the South West Corridor of Victoria are potential sources of significant new generation development. See AEMO's analysis of connection "hubs": Connecting Generator Clusters to the Victorian Electricity Transmission Network, 17 June 2010.

27 The Eyre Peninsula has been mooted as a location with large scale renewable energy resource potential. See ElectraNet's discussion on connection "nodes": South Australian Annual Planning Report 2010, p.107. In addition, the Green Grid Initiative being undertaken by a consortium of Capital, Worley Parsons and Baker McKenzie considers options to harness large scale wind generation on the Eyre Peninsula. See: www.renewablessa.sa.gov.au.

28 See: AEMO, Network Extensions to Remote Areas: Part 2 - Innamincka Case Study, 26 November 2009; Geodynamics, Consultation Paper submission.

3.4 Efficiently connecting new types of generation is challenging

If NSPs knew with certainty the volume and location of generation that would connect over a period of time, it would be relatively simple to match the network investment required to connect it. However, for the reasons outlined below, achieving this outcome is likely to prove challenging as generation investment uncertainty creates difficulties in managing the trade-off between optimising investment and managing stranded asset risks.

Transmission is characterised by lumpy investment, i.e. it can only be provided in discrete, often large amounts. This has been appropriate to date, as historically the size of generation investment has typically matched the size of transmission required to connect it to the network. However, as noted previously, transmission investment needs to accommodate new generation that is relatively small compared to the lumpy transmission investment required to connect it. Under the existing arrangements, transmission is likely to be relatively more expensive for these smaller blocks of generation. The implication is that significant economies of scale are likely to exist where clusters of generators in proximate locations can connect utilising the same infrastructure.

The potential magnitude of efficiency gains will depend on several factors including the number and volume of potential generators, the geographical spread of generators within a cluster and the distance of the cluster from the shared network. However, the examples in the box below demonstrate that there are clear efficiencies to be gained through improved coordination of connections.

Box 3.1: Examples of scale economies captured through coordinated connections

During the Review of Energy Market Frameworks in light of Climate Change Policies, CitiPower and Powercor Australia identified an instance where coordinating a network connection for four generators over 35 kilometres of line would save around $12 million.[29] The network solution for coordinating all four proponents, including construction of a new line, would cost a total of $14 million. This would be shared amongst the four participants. In contrast, considering each connection application independently, the first proponent to connect would incur at least $10 million, including $5 million for the 35 kilometre line. Connecting the remaining proponents would require significant further work.

An illustrative example provided by Grid Australia during the Review of Energy Market Frameworks in light of Climate Change Policies identified that an asset

29 Citipower/Powercor, submission to AEMC Review of Energy Market Frameworks in light of Climate Change Policies: 1st Interim Report, p.5.

built to scale for multiple generators would be about half the cost of options designed for each individual generator.[30]

As an example of generation being connected across a greater area, NERA Economic Consulting (NERA) was recently commissioned by Grid Australia to undertake a case study of a transmission network extension to connect multiple wind generators.[31] In this illustrative case, NERA showed the economies of scale in relation to a coordinated extension to be extensive. NERA considered network developments to accommodate 2000 MW of wind generation, which would require an extension of the network.[32] Based on a stand alone connection cost to accommodate a 500 MW generator of $200m, and a total cost of a shared extension to accommodate a total of 2000 MW of generation of $500m, NERA showed that a generator that incurred a proportional (i.e. quarter) share of the larger extension would pay $125m for that shared connection, or 62 per cent of its stand alone cost.

However, coordinating multiple generators to capture the potentially significant scale economies that may be available is likely to prove challenging for a number of reasons, including:

- difficulties in coordinating multiple parties;
- the temporal nature of the problem; and, as a consequence,
- problems in managing the risks of stranded assets.

Generators are unlikely to be willing to tie their projects to the timeframes of others. Grid Australia has noted that their "members have already experienced reluctance of individual connection applications to tie their project delivery to the timelines of third parties".[33] Similarly, commercial sensitivities may limit the amount of information generators are willing to share. As a result, generators may be hesitant to volunteer sufficient information in a timely way so as to coordinate connections.

In addition, generators who express an interest in connection have different probabilities of their proposed investments being realised over time. This implies that the challenge is not limited to one of coordination, but also one of timing, requiring an assessment of the likelihood of future generation materialising.

However, forecasting future generation is inherently difficult, particularly if site specific. While it can generally be expected that load forecasts will eventually be

30 AEMC 2009, Review of Energy Market Frameworks in light of Climate Change Policies: 2nd Interim Report, June 2009, Sydney, Appendix E.

31 NERA Economic Consulting 2010, *Case Study of the Network Extension – Public Report, 30 July 2010*. Available at www.aemc.gov.au.

32 NERA noted that an expansion of interconnector capacity and deep network augmentation would also be required. However these additional investments would not contribute to the costs incurred by connecting generators and therefore these costs are not included.

33 Grid Australia, Consultation Paper submission, p.8.

realised[34], although possibly later than anticipated, there is a significantly higher risk that forecast generation in a particular area may never materialise. This makes the temporal nature of the problem particularly challenging.

Therefore, in order to achieve economies of scale and help ensure timely connections, an entity needs to be prepared to build extra capacity in the expectation that future generation will materialise. Conversely, that entity must also bear the risk that future generation will not eventuate, leaving them to face the cost of a stranded asset.

3.5 The current frameworks are not robust to all of these challenges

The frameworks that govern the terms and conditions under which generation can access the grid were developed to support the requirements and characteristics of traditional generation investment. However, current frameworks may not be robust to the coordination, timing or risk management challenges presented by different patterns of generation investment.

The coordination problems have recently been lessened to some extent through a Rule change that reduces the restrictions on NSPs from releasing any information received as a result of a connection enquiry or application.[35] However, while improved information release provisions may better facilitate the coordination of multiple generators seeking to connect at a single point in time, challenges still exist as it is unlikely that generators will be ready to commit to connect at precisely the same time.

NSPs are unlikely to consider the full potential of scale efficiencies that could be captured by sizing new assets or connections to enable the more efficient connection of potential future entrants unless they have a high degree of certainty of committed generation to guarantee cost recovery. This is because NSPs currently receive no benefit from, and will potentially incur significant costs, if they oversize their network assets in anticipation of future connections that do not eventuate.

Further, generators are unlikely to be willing to finance additional capacity beyond their own requirements even where building additional capacity is likely to result in lower average costs. In addition to bearing the risk of future generators not materialising, a generator would also risk under-recovery of costs even where generation materialises. This is because there is some ambiguity in the Rules regarding whether an asset funded by a generator may become subject to economic regulation, for example, if load seeks to connect. Similarly, it is not clear whether the generator would be entitled to any compensation if this occurred. Further, there is little commercial incentive for generators to build spare capacity to facilitate a competitor’s connection.

This implies that there is a disincentive for a first mover generator to pay for transmission in excess of its requirements. This disincentive is likely to be heightened

34 This expectation holds in the absence of stronger demand side measures.

35 AEMC 2009, *Confidentiality Provisions for Network Connections*, Rule Determination, 12 November 2009, Sydney.

for generators located remote from the existing network because connection costs will typically be higher.

When multiple connections over time cannot be coordinated or built to an efficient scale, costs to customers may increase through:

- inefficient duplication of network assets, where connections continue to be negotiated on a bilateral basis; and
- inefficient delays in connection or inefficient location decisions from a market perspective as a result of the first mover disadvantage.

Given the potential economies of scale available in network provision, the cost impact on customers from such inefficiencies may be large.

4 Assessment framework

The purpose of this section is to outline the Commission's assessment framework for this Rule change request. The assessment framework will be used to assess both the proposed Rule change and any options that may result in the AEMC making a more preferable Rule to ensure that any framework changes are consistent with promoting the NEO.

4.1 The National Electricity Objective

The Commission's assessment of this Rule change request must consider whether the proposed Rule promotes the NEO as set out in section 7 of the NEL. Under the NEO, a Rule change must:[36]

> "...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."

In assessing this Rule change request against the NEO, the Commission will inform its decision by giving particular consideration to the likely impact of the proposal on the following aspects of the NEO:

- efficient investment in electricity services, particularly connections; and
- efficient risk allocation mechanisms.

While these factors are most relevant to the proposed Rule, which seeks to reduce costs to customers through more efficient connections, this must not be at the expense of the other components of the NEO.

4.2 Efficient investment in electricity services

As noted in the previous section, the objective of this Rule change is to allow the efficient connection of multiple generators with multiple owners in proximate areas over time and to charge generators an efficient price for that service.

Efficient connection outcomes will occur where transaction costs and other barriers to building coordinated connections are minimised. This can be further broken down into the following assessment criteria:

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36 NEL section 88(1).

- Generators are able to connect in a timely manner. This is at risk where large volumes of connection applications and multiple connection applications in the same area are anticipated. This also implies that any process for identifying, planning and constructing a SENE should not be at risk of unnecessary or lengthy delay, which may in turn delay generation investment.

- Generators can be connected with efficiently sized and located assets, taking into account current and likely future generation, to allow scale economies to be captured. This will occur where the framework provides appropriate mechanisms or incentives that allow capacity to be built in advance of expected future connections where it is efficient to do so. The potential scope of the efficiency gains will depend on several factors including the number of potential generators, their geographical spread and their distance from the existing network.

- Generators face efficient cost signals to ensure that generators make efficient locational decisions. This is important for competitive neutrality as well as for efficiency.

- The frameworks should not be unnecessarily complex or burdensome. This should be achieved, where feasible and practical, by utilising arrangements that are consistent with the existing frameworks. Further, any new arrangements should not introduce an unreasonable level of complexity into the Rules and, where complexity is unavoidable, be commensurate with the magnitude of the problem to be solved.

In addition, the frameworks should not be biased towards any particular technology. Some stakeholders considered an environmental objective should be included.[37] However, as acknowledged by these stakeholders in their submissions, the AEMC is bound by its statutory obligation to make Rules that contribute to the achievement of the NEO. It is therefore not our role to ensure the RET is met, but to ensure any behavioural changes as a result of the RET are accommodated in the most efficient way. Consequently, the frameworks should apply to all technologies so as not to distort competition between generation types.

We also note that regulatory certainty plays an important role in ensuring both generation and network investment takes place.[38]

Finally, the frameworks should preserve the open nature of the transmission network such that generators are able to connect to the network on fair and reasonable terms.

37 Vestas, Consultation Paper submission, p.3; Clean Energy Council, Consultation Paper submission, p.2; Pacific Hydro, Consultation Paper submission, p.1.

38 NGF, Consultation Paper submission, p.9.

4.3 Risk allocation arrangements

A final consideration in the assessment framework is the risk allocation arrangements. Typically, efficient outcomes will arise where risk is allocated to those that are best placed to manage it.

There are a number of types of risk associated with planning and building large investments such as transmission assets. These include cost overruns, financing risks, and the risk of default. The allocation of these risks in the case of connections is usually commercially negotiated between NSPs and generators. As discussed previously, any new arrangements should be consistent with existing arrangements where possible. This applies equally to the risk allocation arrangements.

Arguably the largest risk in the case of building additional network capacity in anticipation of future generation connections is that the forecast generation does not materialise, leaving a potentially costly stranded asset. It is this stranded asset risk that is particularly difficult to manage. As discussed in the Consultation Paper, there is tension between allocating this risk to those who are best placed to manage it and allowing efficient connection and pricing outcomes to be achieved.[39]

Consequently, the asset stranding risk may fall on customers as a means to balance efficient investment objectives with efficient risk allocation. In this instance, the Rules should provide appropriate regulatory oversight and other measures such that customer exposure is appropriately managed on their behalf.

39 AEMC 2010, *National Electricity Amendment (Scale Efficient Networks Extensions) Rule 2010*, Consultation Paper, 1 April 2010, Sydney, p.14.

5 The existing frameworks

The purpose of this section is to consider how the existing Rules governing connections and investment operate. The section is divided into two parts:

1. an overview of some of the key concepts and definitions that are contained in the existing Rules relevant to this discussion; and

2. a discussion of how those concepts currently apply to extensions that facilitate generation connection and how they might apply to building additional capacity to accommodate future generation (the status quo).

For ease of discussion, this section focuses on the arrangements pertaining to transmission. While the proposed SENEs framework, if implemented, would also apply to distribution, the scope for scale efficiencies is likely to be greater in transmission due to the nature of the assets and the likely location of clusters of generation. However, we recognise that there will also be issues that are unique to distribution. These issues, including those raised in response to the Consultation Paper, will be given full consideration in developing a draft Rule if required.

5.1 Overview of the current arrangements

In considering this Rule change request it is important to understand the existing arrangements that underpin connections and the construction and funding of extensions. These are set out in Chapters 5 and 6A of the Rules. The first part of this section therefore explores the concepts of, and relationships between:

- how services are classified as either prescribed, negotiated or non-regulated;

- what efficiency test is applied to the assets that provide those services;

- how those assets are funded; and

- what rights network users, in particular generators, have in relation to those assets.

Some of the Rules governing these issues may be interpreted in different ways. There may also be differences between the original intention of the Rules and what outcomes we would now like the Rules to facilitate. Therefore, there may be scope to clarify the existing framework, such as the relationships between:

- assets and the service(s) that they provide; and

- the test to assess the efficiency of a proposed investment and the resulting service classification for services provided by that asset.

The following table sets out a brief overview of these relationships in the context of new investment, which are described in more detail below. Where terms have a defined meaning in the Rules or the NEL, these are indicated by quotation marks where the term is first used. Appendix A provides a glossary of these terms.

Transmission service	Asset	Test	Funding
Prescribed*			
Shared transmission services to standard levels of service	Shared transmission network (may include extensions)	RIT-T (with some exceptions)	Recovered through Transmission Use of System (TUOS) charges under Chapter 6A
Shared transmission services that exceed standard levels of services where they provide system wide benefits	Shared transmission network (may include extensions)	Unclear: the Rules do not specify a test for determining system wide benefits, but appears to be interpreted by market participants to be the RIT-T	Recovered through TUOS charges under Chapter 6A
Negotiated			
Connection services (entry and exit services)	Connection assets	No test in Rules. Implicit test is that the transmission network user is willing to pay charge for service	Negotiated with transmission network user under Chapter 6A framework
Transmission use of system services that exceed standard levels of service	Shared transmission network (may include extensions)	No test in Rules. Implicit test is that the transmission network user is willing to pay charge for service	Negotiated with transmission network user under Chapter 6A framework
Transmission use of system services in respect of transmission network augmentations or extensions required to effect a connection	Shared transmission network and/or extension to effect a connection	No test in Rules. Implicit test is that the transmission network user is willing to pay charge for service	Negotiated with transmission network user under Chapter 6A framework
Non-regulated			
Non-regulated transmission service	Includes an extension required between a connection point and a generator's facilities	No test in Rules. Implicit test is that the transmission network user is willing to pay charge for service	Not prescribed by the Rules

*Note there are two other additional categories of prescribed transmission services that are less relevant to this discussion:

1. Connections services to facilitate a connection to another NSP's network; and
2. Connection services (actual or committed) as at 9 February 2006 to the extent that the relevant assets are included in the Regulatory Asset Base (RAB). See NER clause 11.6.11 for more details.

5.1.1 Classification of transmission services

The current framework under the Rules provides for “connection” to and construction of specific assets. However, it is actually the classification of the service provided by that asset which determines the regulatory requirements that must be complied with in order for the asset to be built and the basis upon which a Transmission Network Service Provider (TNSP) can charge for its use.

Chapter 6A of the Rules divides “transmission services” into three categories: “prescribed transmission services”, “negotiated transmission services” or “non-regulated transmission services”. This classification is important as it determines the form of economic regulation that applies and how the costs of the service will be recovered.

Prescribed transmission services include “shared transmission services” for use of the shared transmission network for conveyance of electricity, which meet (but do not exceed) network performance requirements.

In addition, where a shared transmission service exceeds network performance requirements, it may be defined as providing a prescribed transmission service where a TNSP can demonstrate that the service provides “system-wide benefits”. While the term system-wide benefits is defined[40], the Rules do not prescribe a specific test to demonstrate such benefits.

Negotiated transmission services typically include:

- “connection services”;
- “use of system services” supplied by a shared transmission network which exceed the network performance requirements; and
- use of system services in respect of transmission network “augmentations” or “extensions” required to be undertaken in order to effect a connection.

The Rules are not prescriptive on the links between a particular asset (such as a terminal station) and the service classification associated with that asset. Therefore, there is a degree of flexibility in determining what type of transmission service some assets provide. Grid Australia has recently published guidelines on this issue.[41]

Different forms of economic regulation apply to prescribed transmission services and negotiated transmission services. This reflects differences in the level of market power a TNSP holds and any countervailing power that a "Transmission Network User" may

40 Benefits that extend beyond a Transmission Network User, or group of Transmission Network Users, at a single transmission connection point to other Transmission Network Users.

41 Grid Australia has recently published a guide for categorising transmission services to provide practical guidance on how the service definitions are applied. See Grid Australia, *Categorisation of Transmission Services Guideline*, Version 1.0, August 2010.

have relating to each of the defined services.[42] Prescribed transmission services are regulated under a revenue cap methodology. In contrast, negotiated transmission services are subject to a commercial negotiation regime, supported by a dispute resolution regime.

TNSPs also provide non-regulated transmission services, which the TNSP can provide on a competitive basis with alternative service providers. TNSPs are not obliged to provide such services on the basis that they are not services relating to access to, or use of, the "transmission system" and are therefore contestable. Non-regulated services sit outside the economic regulation framework of the Rules.

The Rules also recognise that the functions of a transmission system asset, and therefore the services it provides, may change over time. The cost allocation principles in the Rules provide that negotiated transmission services may be reclassified to prescribed transmission services provided they meet the criteria in the cost allocation principles.[43],[44] However, the cost allocation principles explicitly preclude prescribed transmission services from being reclassified as negotiated transmission services.[45]

5.1.2 Cost allocation

In addition to determining the form of economic regulation to apply, the classification of services also determines the cost allocation arrangements.

In its Rule Determination for the pricing of prescribed transmission services, the AEMC noted:

> "In order to promote allocative efficiency, transmission prices should generally be set on a 'causer pays' basis where possible. This means that where transmission costs are incurred following a direct request by (or agreement with) a particular network user or users, those user(s) should be required to pay the relevant costs.[46]"

The costs attributable to prescribed transmission services are typically recovered from customers via Distribution Network Service Providers (DNSPs) or load connected directly to the network[47], including services for use of the network[48]. This is because it

42 AEMC 2006, *National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, Rule Determination, 16 November 2006, p.40.

43 However, there is no process in the Rules that determines whether the function of an asset has changed, such that the classification of the transmission services it provides has changed under the Rules.

44 NER clause 6A.19.2(8).

45 NER clause 6A.19.2(7).

46 AEMC 2006, *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22*, Rule Determination, 21 December 2006, Sydney, p.20.

47 There are some exceptions where transmission users, including generators, pay for prescribed entry and exit services. These include actual or committed connection services as at 9 February 2006 to the extent that the relevant assets are included in the RAB. See NER clause 11.6.11.

48 To "standard" levels of service and non-standard levels where there are system-wide benefits.

is difficult to attribute the costs of the shared network to a particular user. The assets providing these services enter the regulatory asset base for a TNSP's transmission system and are subject to the revenue cap set by the Australian Energy Regulator (AER) under Chapter 6A of the Rules.[49] Pricing of individual services is left to the discretion of TNSPs in accordance with their approved pricing methodology[50], guided by the Rules[51] and AER guidelines[52]. TNSPs are also required to apply an investment test to new transmission investments to ensure that any need for investment is met in the most efficient way (subject to a number of exclusions).

The costs attributable to negotiated transmission services are recovered directly from transmission network users, including generators. This is because it is typically straightforward to identify, for example, the costs associated with providing a new connection to the network. The assets used to provide those services do not enter the regulatory asset base and the TNSP's revenue from the provision of these services does not form part of an NSP’s maximum allowed revenue. Part D of Chapter 6A of the Rules regulates the terms and conditions of access, including the prices that may be charged by TNSPs for the provision of negotiated transmission services.

5.1.3 The Regulatory Investment Test for Transmission

Purpose and scope of the RIT-T

The RIT-T, which replaced the former regulatory test from 1 August 2010, establishes the processes and criteria to be applied by a TNSP in considering investment in its transmission network.[53] The purpose of the RIT-T is to identify the investment option which maximises net economic benefits and, where applicable, meets deterministic reliability standards (in which case, if there are net costs, the RIT-T should identify the option which minimises those costs).

The RIT-T was designed as a process to facilitate stakeholder consultation in identifying the most efficient investment option to meet an “identified need”. It was not intended to test the efficiency of a particular proposed investment *per se*, nor does it require that a particular investment that satisfies the RIT-T be undertaken. Rather, the RIT-T provides a process to consider the benefits of a proposed investment relative to alternative credible options.

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49 Note that in Victoria there is no requirement for the AER to approve AEMO's revenue in relation to its Victorian electricity transmission functions. This is because AEMO operates under a tender process for augmentations above a $10 million threshold. This procurement method, which uses competition to select the provider of the service/asset and simultaneously set the revenue requirement, is deemed to promote efficient outcomes. See MCE, *Australian Energy Market Operator Establishment, Legislative Framework: Statement of Proposed Approach*, August 2008, pp. 55-60.

50 NER clause 6A.24.

51 NER clause 6A.23.

52 AER 2007, *Electricity transmission network service providers - Pricing methodology guidelines*, October 2007.

53 For more information on the RIT-T see: AER 2010, *Regulatory Investment Test for Transmission*, June 2010 and AER 2010, *Regulatory Investment Test for Transmission Guidelines*, June 2010.

Importantly, the AEMC has previously noted that the RIT-T process should not be a substitute for the AER's revenue determination process.[54] For this reason, a RIT-T assessment is only one of a number of factors that the AER must consider as part of a revenue determination.[55]

Augmentations and other new transmission investments typically must be assessed under the RIT-T. However, there are several exceptions to this requirement.[56] Of most relevance to this discussion, this includes where:

- the proposed transmission investment will be a “connection asset”; or
- the cost of the proposed transmission investment is to be fully recovered through charges in relation to negotiated transmission services.

The Rules do not expressly exclude applying the RIT-T in such cases. However, due to these exclusions the AEMC understands that the former regulatory test was typically only applied to investments that were intended to provide prescribed services.

In applying the RIT-T, TNSPs are required to consider a range of credible options to meet an identified need and may then proceed with the one that provides the greatest net market benefits (or minimises costs where the investment is required to meet reliability standards). This implies that TNSPs must consider a range of scenarios that meet the identified need of the transmission investment.

The AER has clarified that an identified need might include:

- meeting service standards; and/or
- an increase in the sum of consumer and producer surplus in the NEM.[57]

In considering the role of the RIT-T in building an extension or additional capacity for future generation connections, the latter is of most relevance.

Applying the RIT-T

The RIT-T, as set out in the Rules, comprises two elements:

1. a process element, which includes the procedural consultation requirements[58] and a dispute resolution mechanism[59]. Under the time frames mandated in the Rules, the RIT-T process takes at least 17 months from the issuance of the project

54 AEMC 2008, *National Transmission Planning Arrangements*, Draft Report, 2 May 2008, Sydney, p.56

55 NER clause 6A.6.7(e).

56 NER clause 5.6.5C(a).

57 AER 2010, *Regulatory investment test for transmission application guidelines*, June 2010, p.8.

58 NER clause 5.6.6.

59 NER clauses 5.6.6A and 5.6.6AA.

specification consultation report, and potentially over two years if the TNSP's conclusions are disputed; and

2. the test itself, which examines the costs and benefits of each credible option to establish the option that maximises net market benefits (or minimises costs where the investment is required to meet reliability standards).

In considering the costs and benefits that may accrue as a result of an extension to facilitate future generation connections, a key component of the test is the forecast of generator entry. While forecasting is by its very nature imperfect, NSPs must form a view on the most likely future outcomes, based on the best information available at the time the analysis is undertaken. The AER notes that:

> "…the pattern of new generation development (incorporating capacity, technology, location and timing) is likely to vary depending on which credible option (if any) proceeds. Therefore, each credible option – as well as the base case – will be associated with a different state of the world reflecting different patterns of generation investment and other characteristics and conditions[60]."

The RIT-T describes two possible methodologies for modelling generator entry:

1. least-cost market development modelling, which models projects on the basis of a least-cost planning approach; and

2. market-driven market development modelling, which models projects on the same basis as a private developer.[61]

The AER requires that least-cost market development modelling be used to forecast generation entry, but permits market-driven market development modelling to be undertaken as a sensitivity, where appropriate.[62]

5.1.4 The relationship between the RIT-T, service classification and cost allocation

The Rules clearly link classification of transmission services and cost allocation. However, there is no formal relationship between a transmission investment satisfying the RIT-T and classification of the services provided by means of that investment. Similarly, there is no formal link between an investment satisfying the RIT-T and the subsequent allocation of costs for the relevant services. The difference in approach between Chapter 6A (which relates to the economic regulation of prescribed and negotiated transmission <u>services</u>) and the RIT-T (which is premised on the concept of "transmission investment" which includes both <u>assets</u> and services) means there is a

60 AER 2010, *Regulatory Investment Test for Transmission Guidelines*, June 2010, p.15.

61 AER 2010, *Regulatory Investment Test for Transmission*, June 2010, clause 21.

62 Ibid.

level of ambiguity in relation to the treatment of transmission investments that are subject to the RIT-T.

The AEMC has previously declined to set out a formal link between the RIT-T and prescribed transmission services in the Rules. In its Final Determination on the RIT-T, the AEMC considered that an explicit link was not necessary and that the provisions of Chapter 6A of the Rules provides a discipline and constraint on the costs that are passed on to customers.[63]

The concept of system-wide benefits appears to have been interpreted by some market participants as providing a link between an investment satisfying the RIT-T and the classification of services provided by means of the investment as prescribed transmission services. As discussed above, an asset may provide a prescribed transmission service if it provides system-wide benefits. However, the Rules do not prescribe the way in which system-wide benefits might be measured or demonstrated.

Arguably, if a proposed investment satisfies the RIT-T, this may provide an indication of whether an investment provides system-wide benefits. For example, Grid Australia considers that:

> "In order to demonstrate the presence of system-wide benefits, such works would first be required to satisfy the RIT-T (where applicable thresholds for transmission investment are exceeded) or an equivalent cost benefit assessment.[64]"

This may be an appropriate interpretation for investments where the RIT-T is required to be applied to an investment. However, where the RIT-T is applied to an investment that is not required to undergo a RIT-T assessment (such as a connection asset), the Rules do not address what consequences this would have for service classification and therefore cost recovery. This may be an area for clarification.

5.1.5 Access provisions

Transmission network

Prescribed transmission services are provided on an open access basis. That is, generators do not receive firm access rights for the shared "transmission network"[65] and are not entitled to compensation if they are unable to be dispatched due to congestion. However, generators do have a right to be connected so as to access the "national grid"[66] in accordance with the process under Chapter 5. NSPs are obliged to

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63 AEMC 2009, *(Regulatory Investment Test for Transmission*, Final Rule Determination, 25 June 2009, Sydney.

64 Grid Australia 2010, *Categorisation of Transmission Services Guideline*, August 2010, p.10.

65 Note that the definition of transmission network excludes connection assets.

66 The definition of national grid includes all connected transmission systems and distribution systems within the participating jurisdictions. Note that transmission and distribution systems include connection assets.

facilitate connection in accordance with the Chapter 5 process and subject to network security and reliability requirements.

The Rules do permit generators to negotiate with TNSPs for a higher level of service, including compensation arrangements where the generator is constrained off.[67] The form or calculation of such compensation arrangements are not prescribed, although the Rules do require TNSPs and generators to negotiate in good faith.[68] The AEMC understands that no such agreements have been entered into to date.

Connection assets

In the case of "connection assets" (which are excluded from the definition of transmission network, but included in the definition of transmission system and therefore the national grid), generators have typically had sole use of the assets they have funded in order to facilitate their connection. Therefore, in the absence of outages or constraints on the shared network, generators have been able to be dispatched. While some may consider this constitutes an implicit right to the exclusive use of the connection assets, this is not explicit in the Rules.

The Rules may be interpreted as obliging TNSPs to facilitate connections and access to their entire transmission system, i.e. connection assets as well as the transmission network. For example:

- a TNSP is obliged to review and process applications to connect in relation to its part of the national grid, which includes connection assets;[69]
- the principles which underpin Chapter 5 provide a framework for access to the national grid as well as for connection to a transmission or distribution network;[70] and
- a TNSP is required to provide access to transmission services, being services provided by a transmission system rather than just a transmission network.[71]

The Rules are not prescriptive in relation to what rights, if any, generators have to be compensated if other transmission network users are granted access to the same assets that provide their connection services, which may include extensions required to connect a generator to the network (as discussed further below). However, the AEMC notes that the principles relating to the transmission negotiating framework require the price for a negotiated transmission service to be adjusted over time to reflect the use of

67 NER clause 5.4A.

68 NER clause 5.4A(f).

69 NER clause 5.2.3(d).

70 NER clause 5.1.2(a)(1).

71 NER clause 6A.1.3.

the assets by other market participants.[72] These principles would be given effect through a connection agreement.

Further, the Rules do not specify if or how connection services might be reclassified as prescribed transmission services, for example, if load connects to an asset that provides a connection service. While the Rules recognise that the functions of a transmission system asset, and therefore the services it provides, might change over time, they do not specify what rights, if any, a generator would retain in respect of those assets. Again, in the absence of prescription in the Rules, any rights would be the subject of commercial negotiation.

Non-regulated assets

Non-regulated services, by definition, sit outside the framework for economic regulation of services under the Rules. The Rules therefore do not consider whether, or how, a non-regulated service might become a prescribed transmission service.

However, to the extent that an asset providing non-regulated services forms part of the transmission system, it will be subject to the connection and access regime in the Rules.

If an asset providing a non-regulated service does not form part of the transmission system (and is therefore not subject to the connection and access regime in the Rules) there is a theoretical risk that a third party could seek declaration of the transmission service provided by means of the asset under Part IIIA of the Trade Practices Act 1974 (Cth).

The lack of clarity regarding access rights, particularly around non-regulated services, may provide a disincentive for first mover generators to fund additional capacity.

5.2 Current treatment of network extensions

Some stakeholders consider that the proposed SENE framework is unnecessary and that the existing RIT-T arrangements should be sufficient to promote efficient outcomes.[73]

The following discussion sets out how generators are typically connected to the transmission network and then considers how the RIT-T might be applied under existing frameworks to build extensions or additional capacity in anticipation of future connections.

72 NER clause 6A.9.1(6).

73 Macquarie Generation et al, Consultation Paper submission, p.5; LYMMCO, Consultation Paper submission, p.11; AGL, Consultation Paper submission, p.3; EnergyAustralia, Consultation Paper submission, p.11.

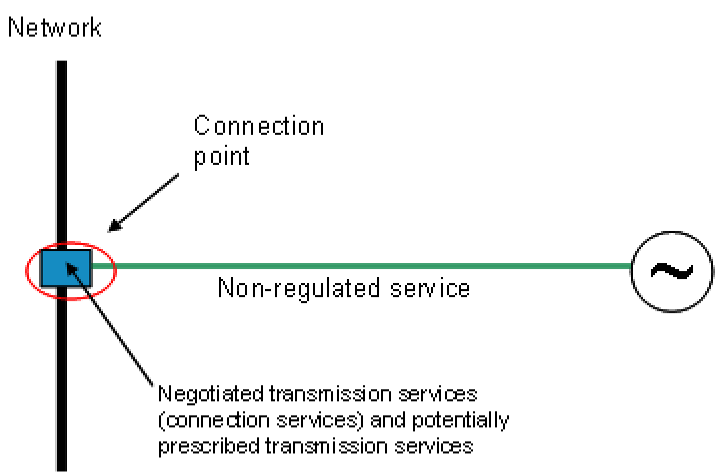
5.2.1 Connecting a generator to the network via an extension

The AEMC understands that if, in order to effect a connection, an extension is required between a "connection point" and a generator's facility, the service provided by means of the extension will either be classified as a connection service (and therefore a negotiated transmission service) or as a non-regulated transmission service.[74] The classification may depend to some extent on the approach of individual TNSPs.

In practice, there is some discretion in determining whether an extension provides a connection (i.e. negotiated) transmission service or a non-regulated transmission service based on considerations such as the length of the extension. However, typically an extension of some length will be classified as a non-regulated service and therefore will not be economically regulated under the Rules. Either way, the costs of the extension are fully recovered from generators.

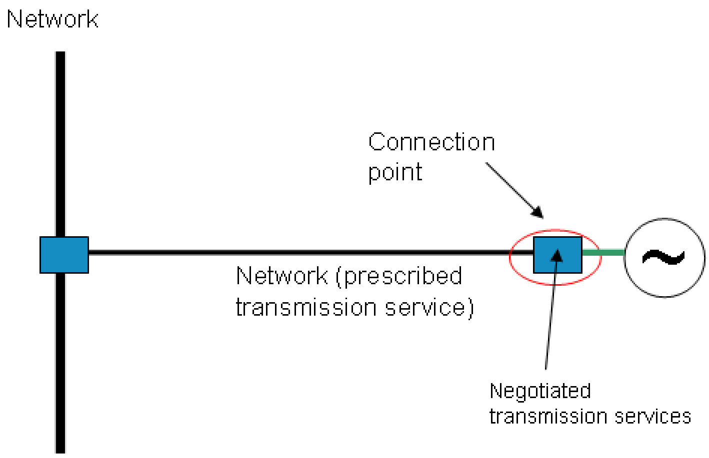
The location of the connection point is subject to negotiation between the generator and the TNSP. The AEMC understands that, in practice, the connection point is typically located at, or close to, the existing network, as in Figure 5.1. However, in theory, it may be located at any point on the extension. This would imply that any portion of the extension between the existing network and the connection point could form part of the shared network, as demonstrated in Figure 5.2. It would therefore be subject to a RIT-T assessment (where the applicable thresholds are exceeded and the costs of the extension will not be fully recovered by the TNSP as charges for negotiated transmission services).

Figure 5.1



74 Even where the extension provides a non-regulated transmission service the TNSP will still provide negotiated transmission services to facilitate the connection of that extension to the network.

Figure 5.2



Where an extension will provide a connection service, the TNSP is not required to apply the RIT-T to the proposed investment. However, the Rules do not prevent a TNSP from doing so. Because the Rules do not contemplate this situation, they do not specify what the consequences would be if the extension passed the RIT-T. Similarly, the Rules do not contemplate applying the RIT-T to a non-regulated transmission service since these services are not economically regulated.

As discussed in section 5.1.4, while there is no formal relationship between the RIT-T and service classification, a TNSP might consider that the extension provides system-wide benefits if it passes the RIT-T and therefore meets the definition of a prescribed transmission service. This would then imply that customers would ultimately fund the extension. This may be considered contrary to Chapter 6A which intends for costs to be allocated on a causer-pays basis where possible[75], i.e. that generators should pay for their connection assets. These same considerations apply to the discussion in sections 5.2.2 and 5.2.3 below.

5.2.2 Building a network extension in anticipation of future generation

In undertaking the planning of future network augmentations, TNSPs might consider the need for a network extension to efficiently connect future generation in a given location even in the absence of formal connection enquiries or applications. As discussed in section 3, a TNSP is unlikely to have an incentive to undertake such an extension as a non-regulated service without certainty of cost recovery. Alternatively, the TNSP could consider whether the extension might meet the definition of a prescribed transmission service and so be funded by customers.

Arguably, as discussed above, an asset might be classified as providing a prescribed transmission service where net market benefits (demonstrated by satisfying the RIT-T) can be considered equivalent to system-wide benefits. The identified need in this case

75 AEMC 2006, *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22*, Rule Determination, 21 December 2006, Sydney, p.20.

would be to increase the sum of consumer and producer surplus in the NEM through, for example, reduced connection costs and more timely connections.

Grid Australia commissioned NERA to develop an illustrative case study to examine the application of the RIT-T and the proposed SENEs framework.[76] NERA found that there are likely to be a number of difficulties in applying the RIT-T to a network extension in the absence of a generator application for connection for a number of reasons. While these results were developed in the context of a case study for the Eyre Peninsula, they are more generally applicable.

In particular, NERA found that establishing the base case generation development scenario and identifying alternative credible options are likely to be highly contentious and subject to dispute. This is partly because there is no clear limit on the scope of the base case or alternative options that may be considered.

For example, in testing a network extension to connect wind on the Eyre Peninsula, it is not clear whether the base case generation development scenario (i.e. the pattern of generation investment in the absence of the network extension) should be other types of generation on the Eyre Peninsula or other renewable generation in other parts of the NEM. NERA found that the results of the RIT-T are highly sensitive to assumptions around these base case market development scenarios.

A possible solution to this, as highlighted by NERA, could be a requirement on AEMO to set out generation development forecasts that provide sufficient information for TNSPs to develop base case assumptions.

Similarly, in considering alternative credible options, a TNSP may need to consider alternative extensions to other generation sites within its own jurisdiction and, potentially, in other jurisdictions. This is because some of the benefits associated with connecting renewable generation will be derived from meeting the RET targets. Arguably, TNSPs would therefore also have to consider alternative credible options outside the NEM given that the RET is an Australia-wide target.

This implies that an alternative option involving an extension to a different location may satisfy the RIT-T.

Since market participants are able to suggest alternative credible options, defining the appropriate scope for the base case and alternative credible options may therefore be a highly contentious and potentially lengthy process, subject to dispute.

Given the difficulties highlighted above, it is unlikely that TNSPs would have an incentive to propose and assess such an extension. Unlike investments that are undertaken to meet service standards, TNSPs do not have stringent obligations to invest in projects that are intended to increase the sum of consumer and producer surplus. While the new RIT-T is intended to provide TNSPs with more scope to consider market benefits at the same time as investing to address reliability

76 NERA Economic Consulting 2010, *Case Study of the Network Extension – Public Report*, 30 July 2010. Available at www.aemc.gov.au.

requirements, network extensions to connect new generation are unlikely to be triggered by a need to meet service standards.

5.2.3 Building incremental capacity

Grid Australia has proposed an alternative approach[77] to the proposed SENEs framework that may be accommodated within the existing Rules. Under this approach, generators fund an extension to meet their connection requirements and the RIT-T is then applied to assess whether building additional capacity to allow future connections would be efficient. This approach is explained in more detail in section 8.4.

Grid Australia considers that assessing the worth of building incremental capacity would clearly bound the scope of alternative credible options. This is because the stand alone cost of meeting the connection requirements of the first connecting generator(s) would be treated as sunk and the RIT-T assessment would be limited to examining the net market benefits of increasing the capacity or changing the configuration of the extension.

Grid Australia has assumed that if building additional capacity satisfies the RIT-T, then that incremental capacity will satisfy the definition of a prescribed transmission service and so the costs of the incremental capacity would be recovered from customers via TUOS charges. The initial extension to connect the first generator(s) would provide a negotiated transmission service and so be recovered from generators. Section 8.4 provides further details on how the costs to be recovered by generators would be allocated over time.

While this approach may be accommodated under the existing Rules, greater clarity regarding when the RIT-T may be applied and the implications for service classification and cost allocation may be helpful. Consideration would also need to be given to whether TNSPs have sufficient incentives to investigate the benefits of building incremental capacity.

77 AEMO has been testing a similar approach. See, for example, AEMO 2010, *Connecting generator clusters to the Victorian Electricity Declared Shared Network: A technical paper*, 16 June 2010.

6 Key design features

The purpose of this section is to outline the key design features for a SENE framework and to compare the features proposed in the Rule change request with possible alternative design features that are available. These features will then be used to form the options set out in section 8.

For each design feature this section outlines:

- the proposed framework set out in the proposed Rule accompanying the Rule change request; and
- possible alternatives.

The key design features we have considered include:

- the trigger for considering whether a SENE should be built to a particular area;
- what investment test should be applied to assess the likely efficiency of the investment;
- how the costs of the SENE should be allocated amongst relevant parties and the structure of the charge that they face;
- what access provisions should apply to the SENE; and
- the regulatory oversight mechanisms that are required.

Some of the alternatives may already be permitted under the existing frameworks, albeit potentially subject to some minor amendments to provide greater clarity, as discussed in the previous section.

6.1 The trigger for considering a SENE

6.1.1 Proposed framework

Under the proposed framework, AEMO would be required to identify potential SENE zones where there is a possibility of substantial scale efficiencies emerging from the development of extensions to that area.[78] In identifying possible zones, AEMO would be required to have regard to a number of criteria, such as the viability and timing of future generation projects and the size or length of the network assets required.[79]

Some stakeholders considered that market participants should play an active role in determining SENE zones.[80] This is envisaged in the proposed Rule, which would

78 Proposed SENE Rule clause 5.5A.2(a).

79 Proposed SENE Rule clause 5.6A.2(2a).

80 LYMMCO, Consultation Paper submission, p.10; NGF, Consultation Paper submission, p.20.

require AEMO to undertake this process as part of its annual National Transmission Network Development Plan (NTNDP).[81] AEMO has already undertaken preliminary consultation on possible SENE zones in anticipation of this Rule change request as part of its NTNDP for 2010.[82]

As part of this process, AEMO would be required to identify the relevant NSP (or NSPs) responsible for preparing options for the development of potential SENEs.[83] Identified NSPs would then publish credible options for the development of potential SENEs in their Annual Planning Reports (APRs) or, in the case of distribution, on their websites.[84] This is intended to be a high level assessment of credible options from SENE zones to their respective networks, and includes connection locations, capacities and indicative network costs. NSPs would also be required to consider (and publish) the impact of each credible option on the shared network.[85]

In their submissions to the Consultation Paper, several stakeholders raised the interaction of the proposed SENE framework with the shared network as an issue that requires further consideration.[86]

While NSPs would not be required to explicitly consider any wider market benefits from augmenting the shared network as part of the SENE process, they are more generally obliged to undertake a network planning process that includes assessing future transmission and distribution needs. Further, consistent with the existing connection arrangements, NSPs would consider and plan any incremental investments to the shared network that would deliver wider market benefits at the time they are planning the SENE. Therefore information would be available to potential generators on possible congestion on the shared network to inform their investment decision.

Following a connection enquiry, NSPs would be required to develop an initial preferred design option for the SENE. To help inform this process, NSPs would be required to publish a notice inviting further connection enquiries in the relevant area. The NSP's response would include a description of any preliminary design options for the SENE, including location, capacity, technical specifications, timetable for development, indicative costs and assumed economic life.[87]

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81 Proposed SENE Rule clause 5.5A.2(1).

82 AEMO 2010, *National Transmission Network Development Plan: Consultation Paper*, 29 January 2010.

83 Proposed SENE Rule clause 5.5A.2(a)(2).

84 Proposed SENE Rule clauses 5.5A.2(b) and (c).

85 Proposed SENE Rule clause 5.5A.2(d)(5).

86 NGF, Consultation Paper submission, p.19; Alinta Energy, Consultation Paper submission, p.14; LYMMCO, Consultation Paper submission, p.12; TRUenergy, Consultation Paper submission, p.8; Clean Energy Council, Consultation Paper submission, p.6; Energy Supply Association of Australia, Consultation Paper submission, p.7; Geodynamics, Consultation Paper submission, p.2; SA Chamber of Mines and Energy, Consultation Paper submission, p.3.

87 Proposed SENE Rule clause 5.5A.3(e).

6.1.2 Alternative approaches for triggering consideration of a SENE

Much of the information on new generation clusters proposed for inclusion in the NTNDP is useful irrespective of whether AEMO is required to identify zones for the purpose of the proposed SENEs framework. Further, TNSPs are already required to take into account the NTNDP in developing their APRs.

An alternative, or possibly complementary, approach to AEMO triggering consideration of a SENE would be for a generator (or group of generators) connection enquiry to trigger consideration of whether building capacity in excess of that generator's requirements would be efficient. While this could be informed by AEMO's NTNDP, it would not be driven by it.

6.2 Investment test

6.2.1 Proposed framework

The proposed 'test' for building a SENE is intended to mirror the test applied to standard connection assets whereby an NSP will build a connection asset where a generator finds it profitable to connect. That is, there is no explicit efficiency test. Rather, costs are assessed by NSPs, and private benefits are assessed by the first connecting generator(s). In addition, private benefits accruing to future connecting generators are implicitly assessed by NSPs. This is discussed further below.

Cost assessment

Under the proposed framework, NSPs would be required to develop and publish a planning report and associated connection offer. The planning report would set out the technical design issues and annual charges payable for an option based on the NSP's best estimate of the expected profile of generation entry. The connection offer would contain the terms and conditions of connection, including the annual SENE charge, preliminary delivery programme and service performance requirements.

The cost information set out within these reports would be important in that it would enable an NSP to determine whether there are likely to be any material scale efficiencies associated with the proposed SENE. The costs of, and hence charges for, a SENE critically depend on the forecast of future generation entry. A comprehensive cost assessment would therefore require NSPs to model generation across the NEM, taking into account the fact that generation entry at one location would affect spot and contract prices and thus lessen the incentive for entry at another location.

To assist NSPs in developing forecasts of generator entry, the AER would be required to develop guidelines outlining the forecast methodologies to apply.[88]

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88 Proposed SENE Rule clause 5.5A.5(i).

Benefit or private profitability assessment

In addition, the information set out within the planning report and connection offer would assist generators in deciding whether it is profitable to pay the proposed SENE charges and sign a connection agreement. Under the proposed Rule, a SENE would be built once a single generator finds it profitable to connect. This is the benefit test that applies to SENEs and is the same test that applies to standard connections. That is, where the private benefits from generation entry exceed the costs, it is assumed generation entry will benefit the market.

The equivalent profitability test for the spare capacity on the SENE would be implicitly performed by the NSP in determining the forecast profile of future generation entry. This is because the NSP would need to consider the profitability of generation entry in assessing the likelihood of generators connecting to the SENE. This would be an iterative process that considers the interaction between the size of the SENE, the required charge to allow cost recovery and therefore the profitability of entry.

Some stakeholders are concerned that NSPs are not well equipped to forecast future generation entry.[89] However, the efficiency of a proposed SENE would also be tested by AEMO, in its role to review generation forecasts, and the AER, in its role to assess the reasonableness of a connection offer. These oversight roles are discussed further below.

6.2.2 Alternative approaches to testing possible SENE investment

Many stakeholders considered that, if the SENE Rule proceeds, further measures are required to better protect customers from the risk of stranded assets.[90] The Consultation Paper raised a number of options, including a higher threshold to trigger building a SENE and an economic test to assess the efficiency of the investment.

Threshold

All stakeholders who commented on the proposal for greater upfront commitments by generators in the form of a capacity threshold consider it would be a beneficial addition to help minimise asset stranding risk.[91] A capacity threshold would require

89 AGL, Consultation Paper submission, p.3; EnergyAustralia, Consultation paper submission, p.24; Energex, Consultation Paper submission, p.2; Ergon Energy, Consultation Paper submission, p.4.

90 EnergyAustralia, Consultation Paper submission, p.7; Ergon Energy, Consultation Paper submission, p.3; NGF, Consultation Paper submission, p.12; LYMMCO, Consultation Paper submission, p.10; Macquarie Generation et al, Consultation Paper submission, p.2; Hydro Tasmania, Consultation Paper submission, p.4; AGL, Consultation Paper submission, p.4; Energy Supply Association of Australia, Consultation Paper submission, p.6; Tasmanian DIER, Consultation Paper submission, p.2.

91 Citipower/Powercor, Consultation Paper submission, p.3; EnergyAustralia, Consultation Paper submission, p.8; Ergon Energy, Consultation Paper submission, p.3; Macquarie Generation et al, Consultation Paper submission, p.2; TRUenergy, Consultation Paper submission, p.4; Hydro Tasmania, Consultation Paper submission, p.4.

firm commitments from generators, demonstrated by signed connection agreements, covering a given proportion of the capacity of the SENE before it could proceed. This approach would essentially strengthen the benefit or profitability test implicitly performed by market participants, reducing the reliance on NSPs to perform this role. That is, a higher cost threshold would place greater emphasis on decentralised market decision making in determining the location and sizing of SENEs.

Where stakeholders suggested a threshold level, this ranged from 25 to 60 per cent of the capacity of the SENE.[92] Any proportion will essentially be arbitrary. However, we can say the following:

- a 100 per cent level of commitment is inconsistent with the fundamental objective of SENEs, which is to accommodate future generation that may not be ready to commit to connect at the time the SENE is built;
- setting the level too low will not significantly contribute to minimising asset stranding risk to customers and will therefore limit the effectiveness of the threshold; and
- setting the threshold level too high risks the SENE never materialising where generators are not prepared to delay commissioning their facilities until sufficient commitment from other generators is obtained.

The level of a threshold trigger would need to strike a balance between these considerations.

The AEMC has also considered the use of a cost threshold rather than a capacity threshold. This would ensure that a given proportion of the capital costs of the investment were underwritten before the investment proceeded.

Efficiency test

The Consultation Paper also raised the possibility of implementing an explicit cost benefit test undertaken as part of the planning process to assess the efficiency of the investment. The test would go one step further than the existing proposal, which would be limited to assessing the costs, potential scale efficiencies and, implicitly, likely private benefits associated with the project. Rather, the test would directly assess the market benefits of the investment. The SENE would only proceed if there was sufficient evidence that the costs were outweighed by the benefits, rather than leaving it to the market to test whether the SENE was privately profitable. This would give a greater level of protection to customers by directly testing the net market benefits of the additional capacity for future generation.

As discussed in section 5.1.3, an investment efficiency test already exists in the Rules. The RIT-T, or regulatory test in the case of distribution, must be applied in most

92 EnergyAustralia, Consultation Paper submission, p.8; Ergon Energy, Consultation Paper submission, p.3; Macquarie Generation et al, Consultation Paper submission, p.2; TRUenergy, Consultation Paper submission, p.1; Hydro Tasmania, Consultation Paper submission, p.4.

instances to assess which investment option best addresses the identified need for investment. However, to date the test has generally been applied to investments that are required to meet growth in load demand. There is, therefore, some uncertainty as to how it might apply in the case of network extensions to connect current and future generation.

Alternatively, a new test could be included in the proposed Rule that is specific to SENEs. This test might be narrower than the RIT-T, in that it would only consider the costs and benefits of the proposed SENE to a defined area. Where net benefits were found, the SENE would be built. This compares to the RIT-T which tests a number of options, which may be outside the area under consideration, or even in a different jurisdiction.[93] Similarly, the new test would not contain the process element of the RIT-T. Instead, stakeholders would be able to provide input into the process consistent with the current SENE proposal, and the AER would be required to review its application.

There was some support from stakeholders for exploring the possibility of including an explicit efficiency test in the proposed SENEs framework. Those stakeholders who considered that a case had not been made for a new framework generally supported the use of the RIT-T as an alternative.[94] The AER considered that it should be given the discretion to include an economic test in the planning guidelines to assist NSPs in determining whether material scale efficiencies exist and the best options for capturing those benefits.[95]

Combination of stronger threshold trigger and economic test

It may be appropriate to have both a stronger threshold trigger and an explicit cost benefit test as they seek to achieve two different things:

- A threshold helps to minimise asset stranding risk by ensuring that a percentage of the investment costs is underwritten by committed generation investment.
- A cost benefit test provides greater assurance that any additional capacity over and above the capacity that is underwritten by firm contracts is economically justified.

If the threshold was set at a relatively high level, an additional cost benefit test may not be necessary. However, if customers were required to underwrite a relatively large proportion of the potential costs of asset stranding then an additional test might be appropriate.

93 See section 5.1.3. for further discussion of how the RIT-T is applied.

94 EnergyAustralia, Consultation Paper submission, p.11; AGL, Consultation Paper submission, p.2; Major Energy Users, Consultation Paper submission, p.28; LYMMCO, Consultation Paper submission, p.11; Macquarie Generation et al, Consultation Paper submission, p.6.

95 AER, Consultation Paper submission, p.4.

Grid Australia's proposed incremental approach to building SENEs, as discussed in section 5.2.3, is consistent with the combined trigger and test. Under Grid Australia's proposal, the threshold trigger for building a SENE would be met by the initial generator (or group of generators) being willing to pay their stand alone cost of connection. This requirement provides an implicit "benefit test" and ensures that a proportion of the investment cost is underwritten by committed generation.

The RIT-T would then be applied to any incremental capacity over and above the requirements of the first connecting generator (or group of generators) to ensure the asset is built to an efficient size where there is a net market benefit. Customers would be required to pay the cost of the incremental capacity, justified on the basis that the additional capacity would provide net benefits to the market.

6.3 Cost allocation and charging methodology

6.3.1 Proposed framework

The SENE charging regime was developed based on the 'causer pays' principle that applies to the current connection regime, whereby generators are required to pay the full incremental costs of their connection to the network.[96] However, in order to provide certainty to NSPs that SENE costs will be recovered, the proposed arrangements would require customers to underwrite the risk of forecast generation not materialising. This was considered reasonable since customers should be the ultimate beneficiaries from arrangements that facilitate the more efficient connection of generation.

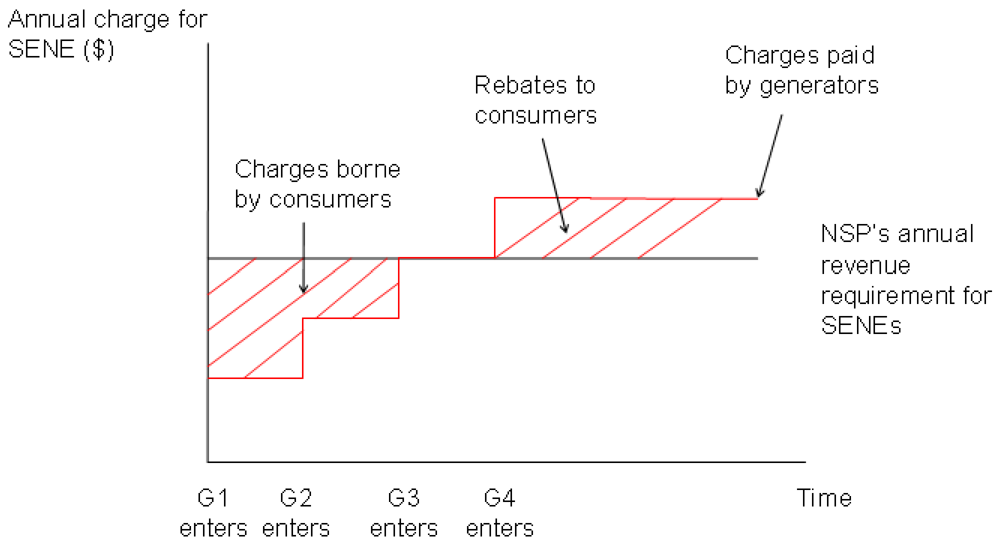
The proposed framework therefore requires that charges for SENEs be set with the expectation that generators will fund the costs of the assets. Charges would be set so NSPs recover their efficient costs, including a return on their investments. Customers would be exposed to costs if generators arrive late or do not materialise, but would benefit if generators arrive early.[97] The revenue earned by NSPs for SENE services would be set to be constant (in real terms) over the economic life of the asset. Although customers would initially fund some spare capacity, they are expected to be repaid, and therefore be cost neutral, over time.

Generators face average cost charges based on their use of the SENE. These charges would be slightly higher than the average proportional cost in order to factor in the anticipated holding costs prior to the SENE being fully utilised. Figure 6.1 illustrates a simplified example of this charging regime. The shaded areas above and below the NSPs annual SENEs revenue requirement will be equal if generation connects as expected.

96 Generators' obligations do not extend into the shared network under either the existing or proposed SENE frameworks although they may chose to fund a network augmentation.

97 Proposed SENE Rule clause 5.5A.12.

Figure 6.1



6.3.2 Alternative approaches to allocating costs and charging

Allocating costs

As noted in section 5.1.2, the AEMC has previously considered that transmission prices should generally be set on a 'causer pays' basis where possible.[98] This means that where transmission costs are incurred following a direct request by (or agreement with) a particular network user or users, those user(s) should be required to pay the relevant costs.

However, SENEs are intended to allow the connection of future generation and therefore an entity must fund the cost of spare capacity until that generation materialises. Arguably, NSPs could be required to fund the difference on the basis that this would provide further incentives for NSPs to efficiently size the SENE. However, NSPs would require a higher rate of return to bear the additional risk and in any case, may prefer to continue to negotiate bilateral contracts rather than take on the additional risk. Further, this would be inconsistent with the current framework that requires customers, rather than NSPs, to underwrite the stranding risk of assets that are built in anticipation of future demand growth.

Therefore, it is likely that, should SENEs proceed, the cost of spare capacity would be underwritten by customers, at least until future generation connects. The following alternative charging arrangements are therefore discussed in that context.

The interaction between the cost allocation arrangements and any explicit economic test also requires consideration. In its response the AEMC's Review of Energy Markets

98 AEMC 2006, *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule*, Rule Determination, December 2006.

in light of Climate Change Policies Final Report, the MCE considered that NSPs should have an obligation to explicitly consider any benefits that may accrue to customers as a result of the SENE.[99] Where such benefits exist, the MCE considered part (or all) of the SENE may be permanently funded by customers. Similarly, in Grid Australia's incremental approach, the cost of the incremental capacity that satisfies the RIT-T is met by customers.

Charging methodologies

Developing a charging methodology for the SENE requires balancing the following (sometimes competing) principles:

- maintaining locational signals for generators;
- maintaining competitive neutrality with generators that connect elsewhere;
- ensuring the efficient costs of the SENE can be recovered, including an appropriate return on investment; and
- overcoming the first mover disadvantage by ensuring the first connecting generator does not face a disproportionately large share of the costs compared to future connecting generators, or that appropriate arrangements are in place to ensure fair cost allocations over time.

Stand alone cost charge

LYMMCO[100] and the NGF[101] considered charges should be based on stand alone cost rather than average cost.[102] Under the stand alone cost charging arrangements, the first connecting generator would pay the charge it would otherwise face to connect in that location if the SENE was not built. If there was more than one generator ready to connect in the same location at the time the SENE was built, they would each face a proportional average charge of the stand alone cost of connecting that group of generators to the existing network. In other words, as a group they would face their stand alone cost.

Subsequent generators connecting to the SENE would then be charged just below their stand alone cost, such that it is marginally cheaper for a new entrant to connect to the SENE than fund a new connection to the shared network. Once the SENE was fully subscribed, or alternatively once the costs of the SENE were recovered, all previously

99 MCE response to AEMC's *Review of Energy Market Frameworks in light of Climate Change Policies Final Report*, December 2009, p.4.

100 LYMMCO, Consultation Paper submission, pp.4-9.

101 NGF, Consultation Paper submission, pp.20-25.

102 We also note that Hydro Tasmania proposed SENE charges could be somewhere between stand alone cost and proportional average cost based on the level of take-up at the start date. Hydro Tasmania, Consultation Paper submission, Appendix 2.

connected generators could receive a rebate such that their charge over time was equal to their average proportional cost.

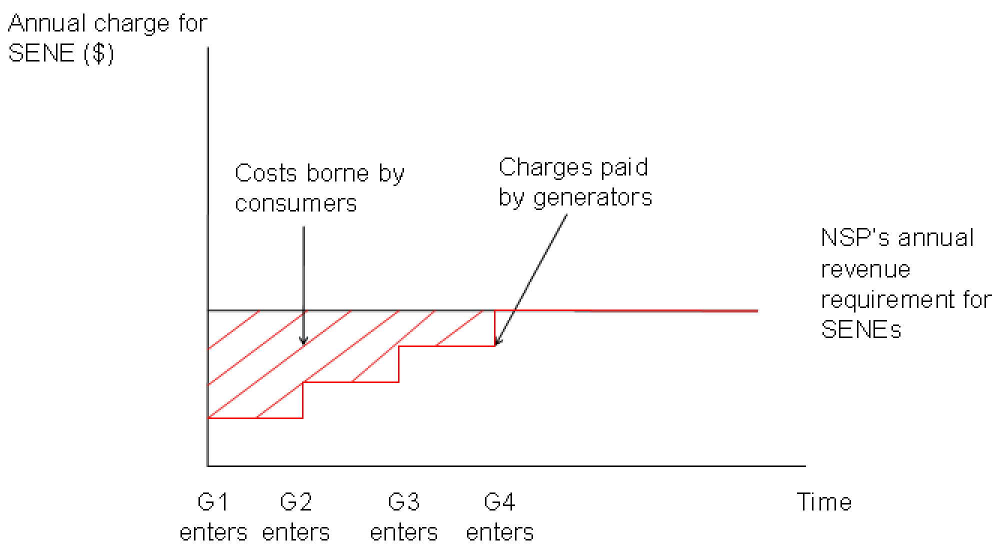
LYMMCO and the NGF consider this approach would not distort locational signals and would address the first mover issue by requiring all connecting generators to pay the same amount (their stand alone cost). Further, it would maximise the opportunity for cost recovery and so assist in minimising risks to customers.

Simplified average cost charge

As discussed previously, the proposed SENEs framework requires that charges for SENEs be set with the expectation that generators would fund the full costs of the assets. This implies that generators would pay slightly more than their proportional average cost to factor in the anticipated holding costs prior to the SENE being fully utilised.

Alternatively, a simplified charge could be applied such that generators pay only their proportional average cost. NSPs would calculate a dollar per MW amount for use of capacity on the SENE. Where there was spare capacity, customers would face that charge, instead of generators. Customers would therefore be expected to face a positive cost over the life of the asset. For this reason, this approach would require some form of test that assesses the net benefits to customers. Figure 6.2 illustrates a simplified example of this charging regime.

Figure 6.2



The AEMC notes that other considerations relating to charging arrangements were raised by stakeholders, such as concern regarding the variability of the charge[103], the

103 Origin Energy, Consultation Paper submission, p.11; TRUenergy, Consultation Paper submission, p.10; NGF, Consultation Paper submission, p.20; LYMMCO, Consultation Paper submission, p.9.

possibility of upfront capital contributions[104] and ensuring NSPs have an incentive to incur efficient costs.[105] These issues will be given further consideration once the broader framework has been established.

6.4 Access provisions

6.4.1 Proposed framework

Under the proposed Rule change, access to a SENE would be based on a generator negotiating an agreed power transfer capability with the NSP as part of the connection agreement. If the generator was unable to access the agreed capacity as a result of another generator exceeding its own agreed power transfer capability, the generator that is "constrained off" would be entitled to compensation. These arrangements do not extend to the shared network and would not apply in the case of outages on the SENE.

To give effect to this arrangement, a generator connected to the SENE would be required to make compensation payments for any trading interval where it generates in excess of its agreed power transfer capability where it has the effect of constraining off another generator connected to the SENE.[106]

These arrangements were intended to ensure that any generator seeking access to the SENE would have access to the shared network consistent with the principles of the open access regime under which the NEM operates. However, as highlighted in the SENEs Rule change Consultation Paper and discussed further in section 8.2, a number of challenges arise from implementing these arrangements.

6.4.2 Alternative approaches to providing access

Stakeholders had mixed views on the efficiency of the proposed capacity arrangements. While several stakeholders offered broad support for the proposed arrangements[107], several were also firmly opposed[108]. Some stakeholders also stated that the issue of capacity rights for generators is better considered as part of the TFR.[109]

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104 Hydro Tasmania, Consultation Paper submission, pp.4-5.

105 TRUenergy, Consultation Paper submission, p.1.

106 Proposed SENE Rule clause 5.5A.1(e). The proposed SENEs framework also provides for a connecting generator to fund an augmentation to the SENE where there is insufficient capacity on the SENE to meet its individual requirements.

107 United Energy Distribution, Consultation Paper submission, p.15; NGF, Consultation Paper submission, p.17; Alinta Energy, Consultation Paper submission, p.12; TRUenergy, Consultation Paper submission, p.6; Infigen Energy, Consultation Paper submission, p.5.

108 EnergyAustralia, Consultation Paper submission, p.22; Ergon Energy, Consultation Paper submission, p.6; SPAusNet Consultation Paper submission, p.5; Geodynamics, Consultation Paper submission, p.6.

109 LYMMCO, Consultation Paper submission, p.12; Clean Energy Council, Consultation Paper submission, p.6; Energy Supply Association of Australia, Consultation Paper submission, p.7.

An alternative to prescribing a method for providing compensation arrangements on the SENE is to allow NSPs and generators to negotiate directly on the terms and conditions of access to the SENE. The Rules currently provide for NSPs and generators to negotiate in good faith on any matters relevant to the provision of connection, which includes the level of power transfer capability that the generator will be entitled to[110]. The Rules also allow generators to negotiate with NSPs regarding access to the network, including compensation arrangements where a generator is constrained off.[111]

This would also imply exclusion from the proposed Rule of the proposed provisions that govern how further connections may be facilitated once the SENE was fully subscribed. In this respect, we note that the Rules currently require NSPs to consider the impact of a new connection on the ability of other generators to evacuate their power.[112] This does not imply that generators will never be constrained off, but provides a mechanism for limiting the impact on other market participants.

6.5 Regulatory oversight

6.5.1 Proposed framework

The proposed Rule includes a series of checks and balances to help mitigate risk to customers of inefficiently sized SENEs. First, it includes a requirement for AEMO, within thirty business days of the publication of a connection offer, to review the relevant NSP's forecast generation profiles.[113] In addition, as proposed by the MCE, the proposed Rule would require that new projects only go ahead if AEMO approves this forecast.

If AEMO considered that forecast generation entry was likely to be lower than estimated by the NSP, this may result in a smaller project being approved by the AER, or a higher charge. This would assist in reducing stranded asset risk to consumers.

In addition, following the publication of a connection offer, the proposed Rule provides for any party, by submission to the AER, to comment on its contents.[114] Together, these elements would ensure that the proposed project is subject to well informed scrutiny by an independent body and interested parties.

Further, the proposed SENEs Rule provides for the AER to disallow a project should it consider that, based on the information before it, the generation forecast or cost

110 NER clause 5.3.6(f).

111 NER clauses 5.4A and 5.5.

112 NER clause 5.3.5(d).

113 Proposed SENE Rule clause 5.5A.7.

114 Proposed SENE Rule clause 5.5A.6.

estimates are not sufficiently robust.[115] In particular, the AER may disallow a project where it considers:

- the forecast generation profile, design option for the SENE, expenditure required or the economic life of the SENE is not reasonable;
- there was a manifest error in the NSP's calculations; or
- the SENE connection offer was not prepared in accordance with the Rules.

The ability to disallow a SENE project, along with other elements described above, forms the basis of the administrative arrangements that would protect the interests of customers.

6.5.2 Alternative approaches to regulatory oversight

Stakeholders generally considered these oversight mechanisms were appropriate but that other risk management mechanisms, such as a stronger threshold and application of an economic test, might be required (as discussed previously).

In its submission, the AER considered that the role of AEMO in the SENEs process should be expanded to provide it with discretion to advise the AER on any aspects of the relevant SENE connection offer and planning report. The AER considered this to be appropriate given AEMO's expertise in transmission issues. In addition, the AER noted that this would be consistent with AEMO's role of providing advice on grid transmission development or projects which could affect the transmission grid under s49(2)(c) of the NEL.[116]

A number of stakeholders considered that a conflict of interest may arise in Victoria where AEMO has a role in planning as well as the general oversight role proposed in SENEs.[117]

In addition, SPAusNet considered that the division of roles and responsibilities between AEMO and the asset owners in Victoria required further clarification in any further SENE Rule change drafting.[118] In line with this view, AEMO considered that the final version of the Rules would need to include provisions clarifying which functions would be performed by which party in Victoria.[119]

Further consideration may need to be given to the role that AEMO plays in Victoria and how that relates with its more general oversight function as set out in the proposed SENEs framework. In addition, the AER's role, and potentially AEMO's involvement,

115 Proposed SENE Rule clause 5.5A.8.

116 AER, Consultation Paper submission, p.4.

117 Infigen Energy, Consultation Paper submission, p.3; Grid Australia, Consultation Paper submission, p.11.

118 SPAusNet, Consultation Paper submission, p.4.

119 AEMO, Consultation Paper submission, p.10.

may require further consideration. This is particularly relevant if an economic test is included in the framework. For example, it may be appropriate to expand the AER's role to include reviewing the application of the test.

6.6 Summary of options for consideration

The AEMC has considered the various possible design features outlined above and constructed five possible options for stakeholder consideration.

Options 1 and 2 are based on the existing proposed SENEs framework, with some revisions to strengthen the risk mitigation mechanisms and simplify the proposal. The key differences between these options and the proposed Rule change are:

- Option 1 introduces a cost threshold trigger such that the SENE will only be built once 25 per cent of the capital costs of the investment are underwritten by firm connection agreements with generators; and
- Option 2 also includes a cost threshold trigger, but further strengthens the risk mitigation measures through the explicit application of an economic test. In addition, the proposed framework is simplified by removing the regulated compensation arrangements, leaving these to be negotiated.

Option 3 is based on an approach put forward by Grid Australia. The RIT-T is applied to incremental capacity above that required to connect a first generator (or group of generators). The first generator(s) would pay the stand alone costs of its connection to the network in the absence of a scale efficient connection. Subsequent connecting generators would contribute to the stand alone cost of the first generator(s). The cost of any incremental capacity justified by the RIT-T would be met by customers.

Option 4 is a variation on the Grid Australia approach with different cost recovery arrangements such that generators are expected to pay for the SENE over time, provided that generation materialises as forecast. Customers would continue to underwrite the risk of asset stranding.

Option 5 maintains the principle that generators should face the costs incurred in connecting them to the network. However, instead of recovering this as a negotiated service, a new type of prescribed service would be introduced that is paid for by generators. Customers would still underwrite the cost of any spare capacity, but with a simplified charging framework.

The following table briefly summarises the characteristics of each option. These options are described in more detail with accompanying analysis in section 8.

Key design feature	Option 1	Option 2	Option 3	Option 4	Option 5
Trigger for considering a SENE	AEMO identifies zones. NSPs identify credible options	AEMO identifies zones. NSPs identify credible options	A generator connection enquiry	A generator connection enquiry	A generator connection enquiry
Investment test	Implicit in NSP planning and firm connection agreements	Explicit economic test applied to assess merits of SENEs plus firm connection agreements	Signed connection agreement with first generator, RIT-T applied to incremental capacity	Signed connection agreement with first generator, RIT-T applied to incremental capacity	RIT-T is applied to the entire investment proposal
Cost allocation and charging methodology	Generators pay a proportional average cost. Customers underwrite risk but should face no cost over life of asset if generation enters as expected	Generators pay a proportional average cost. Customers underwrite risk but should face no cost over life of asset if generation enters as expected	First generator pays stand alone cost. This charge reduces as other generators connect. Customers pay for incremental capacity	First generator pays stand alone cost. Customers underwrite costs of incremental capacity. Both these charges reduce over time with further connections	A new type of prescribed transmission charge is introduced relating to SENEs, which generators pay. Customers pay for spare SENE capacity
Access provisions	Mandated compensation arrangements	To be negotiated between generators and NSPs	As per the shared network	As per the shared network	As per the shared network
Regulatory oversight	AER has power of veto, AEMO reviews forecasts	AER has power of veto, AEMO reviews forecasts	AER reviews application of RIT-T, AEMO reviews forecasts	AER reviews application of RIT-T, AEMO reviews forecasts	AER reviews application of RIT-T, AEMO reviews forecasts

7 Implementation issues: how the design features fit within the existing framework

The purpose of this section is to discuss how the key design features outlined in the previous section fit in with the existing connections framework, outlined in section 5. This discussion will then form part of the assessment of the options described in the next section in the context of considering the relative complexity of, and implementation issues associated with, each option.

Incorporating SENEs into the existing framework is a key challenge to address if the Rule is made. Ideally, a single framework within the Rules would be able to address connections for both single and multiple network users and, more generally, would be robust to future changes in the pattern of generation investment. However, this would likely require a review of the current connection framework which is outside the scope of this Rule change request.

However, SENEs do not naturally fit into the existing Rules. The current frameworks governing connections to the network and new transmission investment were developed during a different period in the NEM, when a single, relatively large scale generator typically connected to the network using a dedicated asset. This paradigm is now changing as we seek to allow more efficient outcomes via sharing of extensions required to facilitate connections.

7.1 Cost allocation

The principles behind the allocation of the costs of the SENE were discussed in section 6.3.2. This section discusses how these principles might fit into the existing Rules frameworks. In particular, it considers how the principle that costs should be allocated on a 'causer pays' basis where possible, fits in with the existing service-based charging arrangements and the implications of applying the RIT-T.

The challenge that arises in considering how costs for the SENE might be allocated is that the Rules do not envisage the nature of a service changing from a prescribed transmission service to a negotiated transmission service. In other words, they do not allow for costs that were once recovered from consumers to subsequently be recovered from generators. However, the proposed SENEs framework introduces exactly that situation: customer funding is required to initiate the project, however over time the SENE is expected to assume the characteristics of a connection asset.[120]

7.1.1 Proposed SENE framework – negotiated services

As discussed above, generally customers pay for prescribed transmission services via DNSPs and generators (as Transmission Network Users) pay for negotiated transmission services. However, under the proposed SENEs framework, services

120 At some point, load may connect to the SENE or it may form a loop to the shared network and so may become characterised as a prescribed transmission service.

provided by means of the SENE would be characterised as negotiated services yet customers would underwrite the risk to ensure NSPs receive a constant revenue stream prior to the SENE being fully subscribed. Further, the SENE would be characterised as part of the transmission network, yet the proposed SENE Rule specifically excludes the application of the RIT-T to this extension.

These arrangements are required to fit in with the existing service classification and cost allocation arrangements. They also preserve the principle that generators should pay for their connections by requiring that the extension cannot be considered as providing a prescribed transmission service. However, some stakeholders consider these arrangements essentially (but not explicitly) introduce a third category of regulated transmission service into the Rules, as a SENE does not fall comfortably within the existing negotiated (or prescribed) service categories.[121]

Further, because a transmission service cannot be reclassified from a prescribed transmission service to a negotiated transmission service, any costs that customers are required to fund (at least initially) and future rebates once a SENE is fully subscribed, cannot be recovered from, or returned to, customers through their usual TUOS charges. Therefore, an alternative mechanism is required to allow this cost recovery and rebate to occur. This introduces an additional level of complexity into the proposal.

7.1.2 Incremental approach – negotiated and prescribed services

As discussed previously, while there is no explicit link between a proposed transmission investment satisfying the RIT-T and services provided by means of the SENE being classified as a prescribed transmission service, this appears to be the case in practice. However, this implies that if a SENE (in its entirety) satisfies the RIT-T and is classified as providing a prescribed transmission service, those costs would be recovered from customers. Connecting generators would face no charge for the use of the SENE.

Grid Australia's proposed approach to building incremental capacity implies that the SENE would provide a combination of prescribed and negotiated transmission services. The incremental portion of the SENE over and above the requirements of the first connecting generator(s), provided it satisfies the RIT-T, would be defined as providing a prescribed transmission service. The portion of the SENE paid for by the first connecting generator(s) would remain a negotiated transmission service.

7.1.3 A new category of prescribed transmission service

Alternatively, a new type of prescribed transmission service could be introduced that is specifically related to shared extensions required to facilitate connections, such as SENEs. Charges for the new prescribed transmission service would be levied on

121 Grid Australia, Consultation Paper submission, p.10; SPAusNet, Consultation Paper submission, p.3.

generators. This would allow the existing charging arrangements for recovering costs from customers to be maintained, while ensuring generators still faced a charge for their connection. This proposal is discussed further in section 8.6.

7.2 Investment test

One of the potential design features of SENEs is to introduce an economic test to assess whether a proposed network extension is efficient. As discussed above, such a test already exists in the Rules and must be applied for the majority of investments. Using the RIT-T would provide consistency with the current framework. However, there are several reasons why the RIT-T as it is currently structured may not be the most appropriate option in the context of the proposed SENE framework.

This section discusses some of the implications of applying the RIT-T to the proposed SENEs framework. It first considers the implications of the process elements that TNSPs are required to follow in applying the RIT-T. It then considers the application of the test itself.

7.2.1 RIT-T process

The AEMC understands that part of the reason some stakeholders are concerned with applying the RIT-T to SENEs is because of the time required to consult and potentially to resolve disputes.[122] Given the significant commercial interests that are tied to the outcomes of the SENE, there is a high chance that disputes will be raised, potentially extending the time taken to undertake a RIT-T to over two years.

The longer it takes to resolve such disputes, the greater is the likelihood that the opportunity for coordination will dissipate. Further, there is a greater risk that the objective of timely connection may not be met.

In contrast, the proposed SENEs framework is intended to have a much shorter time frame. NSPs would have six months from the publication of AEMO's NTNDP to conduct a review of credible options for developing a SENE and publish the credible options. Once an NSP receives a connection enquiry, they would have at least ten weeks to provide a response depending on the length of the notice period inviting further enquiries, which must be at least twenty business days.

Following a connection application, NSPs would have a further ten weeks to publish a SENE planning report and connection offer. The proposed SENEs framework then provides a further twelve weeks for the SENE regulatory approvals process - AEMO would have thirty business days to review the NSP's forecast generation profile (during this period, any party may also raise an objection to the AER) and the AER

122 For example, Infigen Energy considers that the RIT-T process is slow and laborious and therefore not appropriate for "the relatively rapid roll outs of SENEs and their associated renewable generation required to meet the Government's expanded RET target". Origin Energy was of a similar view. See: Infigen Energy, Consultation Paper submission, p.4; Origin Energy, Consultation Paper submission, p.4.

would have a further 30 business days to approve (or otherwise) the SENE connection offer[123].

The SENEs process itself may also be subject to dispute. Objections must be considered by the AER in deciding whether to approve a connection offer.[124] If a connection offer is not approved, the NSP has a further thirty business days to submit a revised planning report and/or connection offer.[125]

Further, AEMO considered that the proposed timeframes for developing the planning report and connection offer are unreasonably short.[126] AEMO considered that these time frames should not be fixed.

7.2.2 Application of the RIT-T

Scope

As discussed in section 5.1.3, the RIT-T requires the assessment of a number of alternative credible options. In principle, this could require TNSPs to examine options that include, for example, building a SENE in another jurisdiction. This may make it difficult to narrow the scope of the base case and alternative credible options.

Deriving generation forecasts and costs

As it is currently drafted, the RIT-T requires least-cost market development modelling to be used to forecast generation entry and permits market-driven market development modelling where appropriate.[127] The AER has clarified that the latter would be applied as a sensitivity.[128]

In contrast, in the case of SENEs, it may be more appropriate to apply market-driven market development modelling to derive a forecast of generation entry. This is because achieving the potential economies of scale hinges critically on the forecast being as accurate as possible such that expected generators materialise. This implies deriving forecasts on the same basis as private investors.

While least-cost market development modelling may provide a reasonable proxy, the two modelling techniques might be expected to diverge because signals to generators - including those provided by the energy market and signals about the costs generators cause on the transmission network - are not perfect. However, market-driven market

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123 Note that the connection agreement would be subject to environmental and planning approvals, consistent with existing requirements under NER clause 5.3.7(d).

124 Proposed SENE Rule clause 5.5A.8(b)(2).

125 Proposed SENE Rule clause 5.5A.8(d).

126 AEMO, Consultation Paper submission, p.8.

127 AER 2010, *Regulatory Investment Test for Transmission*, June 2010, clause 21.

128 AER 2010, *Regulatory Investment Test for Transmission Guidelines*, June 2010, p.17.

development modelling may prove to be more contentious as it requires more controversial assumptions.

Under the proposed SENE Rule, the AER has been tasked with producing guidelines to assist NSPs in developing generator entry forecasts.[129]

Likelihood of SENEs passing the RIT-T

The AEMC understands that some stakeholders are concerned that a proposal for a SENE would be unlikely to pass the RIT-T. However, analysis suggests that under certain conditions, the SENE approach and the RIT-T might be expected to derive the same outcomes. This section provides a brief summary of why this is the case. Appendix B provides further discussion.

There are two key areas where the analysis under the SENE approach and the RIT-T may differ:

- the expected effect of the SENE on future generation entry; and
- for a given forecast of generation entry, how the benefit associated with that change in entry is calculated.

Where the same modelling approach for forecasting generator entry underpins both the RIT-T and the SENE analysis, the same forecast effect of the SENE on future generation entry will be reached. However, as discussed above, these approaches may differ, where market signals are not perfect.

In terms of benefits, the SENE analysis undertaken by NSPs asks whether the use of the SENE is more <u>profitable</u> than locating elsewhere, i.e. it delivers a higher net <u>private</u> benefit. In contrast, the RIT-T asks whether it is more <u>efficient</u> for a generator to connect and use the SENE than to locate elsewhere, i.e. it delivers a higher net <u>market</u> benefit. In many cases, these two types of benefits would be expected to provide similar outcomes.

7.3 Interaction with the shared network

This section comprises two parts. First it considers how the RIT-T and SENE approaches differ in their treatment of the shared network. Second, it considers the wider implications of the SENE approach where the existing network may not have sufficient capacity to facilitate connection of the SENE.

7.3.1 Comparison between the RIT-T and SENEs approaches

One area where the RIT-T and the SENE analysis might be expected to give materially different outcomes is where generation connected to the SENE is expected to have a

129 Proposed SENE Rule clause 5.5A.5(i).

more substantial impact upon future shared network investment than generation that connects elsewhere.

If the RIT-T was applied to test the efficiency of a potential SENE investment, the analysis would factor in any subsequent impact on the shared network. While generators connecting to the SENE would not be required to pay for any shared network augmentations (although they could choose to do so)[130], this would increase the costs associated with the proposed investment.

In contrast, the SENE approach does not explicitly factor in any costs that might be imposed on the shared network. This is because generators do not currently face a complete signal of the costs that they impose on the shared network. However, the proposed Rule does contain provisions that would require TNSPs to consider and publish the likely impact of the SENE on the shared network.[131]

7.3.2 Considering the shared network under the SENE approach

The proposed SENE Rule would mirror the existing arrangements for connections in considering the impact on the shared network. That is, generators would not have to pay to augment the shared network unless they chose to do so.

However, the AEMC understands that some potential SENE zones could connect generation in the order of 1000 to 2000 MW to the national grid. In many instances an upgrade to the shared network would be essential to connect this magnitude of generation.

In practice, this network augmentation could take one of two forms:

- the existing line to which the SENE connects may be upgraded (Figure 7.1); or
- the SENE may be extended to the point where the existing network is capable of facilitating that connection, which could run parallel to an existing transmission line (Figure 7.2).

The proposed SENE Rule does not directly address how such augmentations would be facilitated.

130 Under the current arrangements, generators are not required to pay deep connection charges. However, where a connection cannot proceed without augmentation to the shared network and that augmentation does not satisfy the RIT-T, the generator may choose to pay for it as a negotiated transmission service. See NER clause 5.4A(f)(3).

131 Proposed SENE Rule clause 5.5A.2(d)(5).

Figure 7.1

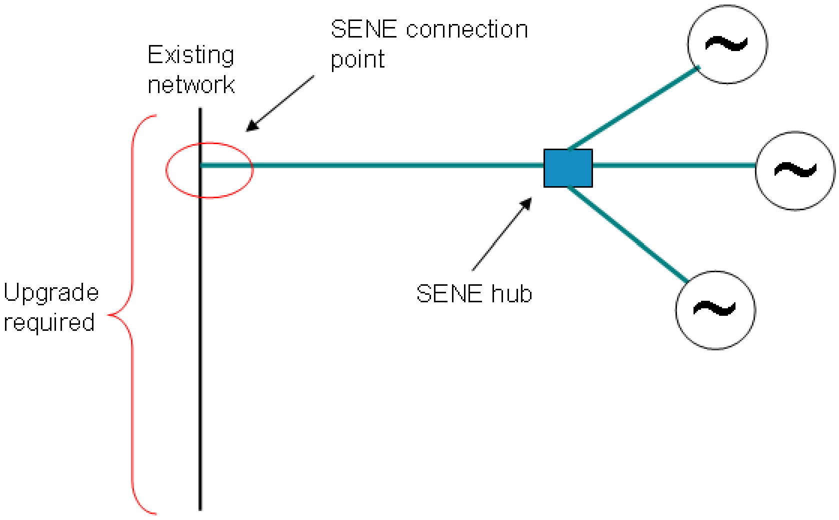
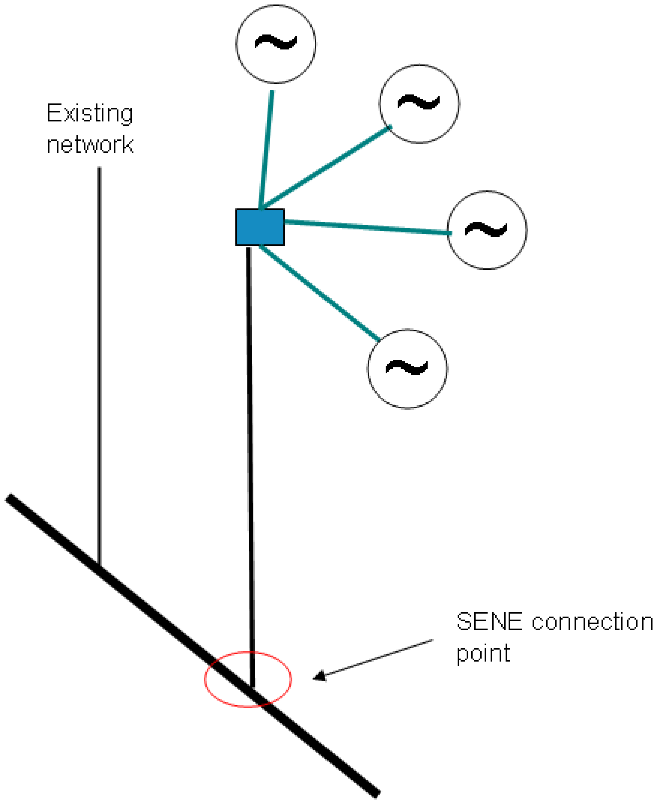


Figure 7.2



Typically, augmentations to the shared network are classified as prescribed transmission services. This first requires that the proposed augmentation has satisfied the RIT-T. Alternatively, if a proposed augmentation does not satisfy the RIT-T, it may be funded by network users, including generators, in which case it is classified as providing a negotiated transmission service.

Augmentations as prescribed transmission services

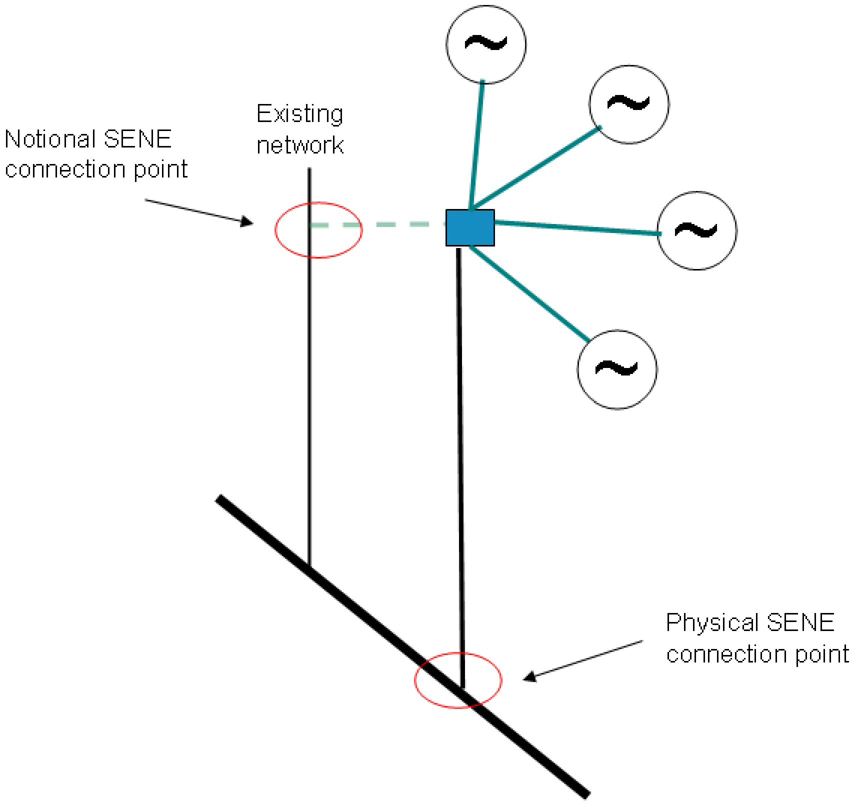
In the context of Figure 7.1, a network upgrade could potentially occur where the proposed augmentation passed the RIT-T.[132] While this process could be performed in tandem with the SENE development process, it would likely take longer than the process for assessing the SENE and could therefore have the effect of slowing down the SENE development, as discussed previously.

When additional capacity is required such that it is necessary to provide new infrastructure rather than upgrade existing lines, it may be necessary for the SENE to run parallel to part of the existing network to a point where the SENE can be connected (as in Figure 7.2). This may raise further difficulties. In this case, it is difficult to separate the assets providing the connection from the assets that effectively provide the upgrade of the shared network. In practice, one solution might be to create a "notional connection point" somewhere on the line closest to the SENE hub (see Figure 7.3). The RIT-T would then be applied to the difference in cost between the physical connection and the notional connection. Where the RIT-T was satisfied, the larger SENE would be built.

Customers would fund the notional network upgrade and generators would fund the cost of the SENE to the notional connection point. However, this would then imply that part of the SENE would provide a negotiated transmission service and the remainder would provide a prescribed transmission service. If the nature of access differed between the two, this may be difficult to implement in practice.

132 Unless the proposed investment fell into one of the exclusions to which the RIT-T does not have to be applied.

Figure 7.3



Augmentations as negotiated transmission services

Where a potential augmentation does not satisfy the RIT-T, three possible outcomes arise.

First, in practice, the capacity of the SENE may be limited by the capability of the existing network in the absence of an augmentation. This would occur where no generator was willing to fund the necessary augmentation to facilitate a SENE with a greater capacity. Consequently, the opportunity for capturing scale efficiencies would be limited.

Second, generators could be required to pay for any augmentation to the existing network that would be necessary to connect an efficiently sized SENE to the shared network as a negotiated transmission service (as in Figure 7.1).

Third, the SENE could be defined as extending to the point on the shared network where the existing network was capable of facilitating that connection, even where it runs parallel to an existing transmission line (as in Figure 7.2).

The second and third of these options may be unlikely to eventuate in practice. This is because the additional costs of augmenting the network may exceed the stand alone cost of an individual connection to the network. In this instance, the SENE is unlikely to be built as generators would instead opt to build dedicated assets. Further, the second and third options are equivalent, in effect, to a deep connection charge. Mandating either of these options may therefore be inconsistent with the existing framework which does not require generators to contribute to the cost of augmenting the shared network.

7.4 Access provisions

The proposed SENE Rule sets out arrangements for compensating generators where they are constrained off the SENE below their agreed power transfer capability as a result of another generator exceeding its own agreed power transfer capability. These access rights would apply only to the SENE, i.e. they do not extend into the shared network.

As the network continues to develop over time and as demand increases, it is possible that load may wish to connect to the SENE or the SENE may have more than one connection point to the shared network. This creates the possibility of inconsistencies in access to the network between generators connected to the shared network and those connected to the part of the network that was previously characterised as a SENE.

The Consultation Paper raised two options for addressing these concerns: ring fencing the SENE and terminating the compensation arrangements following an appropriate notice period. Both of these options are problematic and there was no consensus amongst stakeholders about which option, or alternative solution, might be preferred.

As discussed in section 5.1.5, access rights are not always clearly defined in the Rules, particularly with respect to connection services. However, no compensation arrangements are currently mandated in the Rules. While there is provision for compensation to be paid to generators where they are constrained off, these arrangements are left to be negotiated between generators and NSPs.[133] Arguably, for consistency with the existing frameworks, the terms and conditions of access may therefore be best left to negotiation between NSPs and generators.

133 NER clause 5.4A.

8 Options and analysis

The purpose of this section is to set out the options on which the AEMC seeks stakeholder comments. First, it provides a brief recap of the assessment framework set out in section 4. It then provides a description of the key design features and analysis of each option. This analysis draws on the assessment framework and the implementation issues described in section 7.

This section is not intended to provide a full assessment of each option. Rather, it intends to highlight for the purpose of consultation how the different options may influence outcomes to allow for the efficient connection of multiple generators with multiple owners in proximate areas over time and to charge generators an efficient price for that service.

In considering the options set out in this section, we would ask stakeholders to consider the following questions:

- which option best promotes the NEO and why;
- whether there are other broad implementation issues associated with the options that have not yet been identified; and
- whether there are other options we should consider which may better address the issues identified by this Rule change and, if so, how they would better promote the NEO.

In addition, stakeholders may wish to consider whether there is merit in combining certain options, for example, Option 1 or 2 with Option 3 or 4.

One of the difficulties in developing an appropriate framework for implementing SENEs is that there is no unique configuration for a SENE. For example, the proposed Rule essentially envisaged a "hub and spoke" configuration. However, some potential SENE zones may be characterised by a long SENE with generators connecting at more than one hub. Similarly, a cluster of generators may be located relatively close to the existing network or be relatively remote.

Generally it would be preferable to have a single framework that applies to all connections. However, these different characteristics suggest that it may be appropriate to provide NSPs with a number of tools to allow the efficient coordination of clusters of generators over time, depending on the nature of the proposed SENE. Importantly, efficient coordination should not be restricted to certain configurations or locations. However, this may provide a challenge in deriving a "one size fits all" approach to the connection framework.

8.1 Overview of the assessment framework

As set out in section 4, we have developed an assessment framework to evaluate both the proposed Rule change and any options that may result in the AEMC making a more preferable Rule. This is to ensure that any framework changes are consistent with promoting the NEO. The five key assessment criteria are as follows:

- generators are able to connect in a timely manner;
- generators face efficient locational signals;
- potential to capture scale economies;
- frameworks are not overly complex; and
- stranded asset risk is appropriately managed.

In addition, the frameworks should not be biased towards any particular technology and should ensure that generators can access the national grid on a fair and non-discriminatory basis. Regulatory certainty also plays an important role.

There are likely to be a number of trade-offs between these criteria. The key trade-off, and the inherent difficulty with SENEs, is the trade-off between stranded asset risk and pre-building to allowing timely connections and potentially capture scale economies.

Similarly, there are trade-offs between the complexity of the framework and consistency with the existing Rules. As discussed, there are some provisions of the Rules that may benefit from clarification. Further, certain characteristics of SENEs do not fit naturally within the existing frameworks. This makes it difficult to provide consistency without introducing additional complexity.

8.2 Option 1: SENEs with a cost threshold trigger

8.2.1 Key design features

Option 1 is based on the existing proposed SENE framework, as described in some detail in section 6 and summarised in the table below. However, this option varies from the proposed Rule by including a cost threshold trigger as an additional measure to strengthen the investment test so as to further protect customers.

Key design feature	Option 1
Trigger for considering a SENE	As part of its NTNDP, AEMO would identify “SENE zones” where there is a possibility of substantial scale efficiencies emerging from the development of extensions to an area. NSPs would identify credible connection asset options and undertake preliminary planning which would be reported in their APRs or on their website.
Investment test	NSPs would consider whether there are likely to be scale efficiencies from building a SENE. The size of the SENE is based on a forecast of how many generators would find it profitable to enter.

Key design feature	Option 1
	Construction of a SENE would be triggered once an NSP has signed connection agreements with generator(s) that cover at least 25 per cent of the capital cost of the SENE. While NSPs would not be prevented from building a SENE that had not reached the trigger, they would not be able to recover any costs from customers until the 25 per cent threshold was reached. TNSPs would therefore be exposed to the risk of future generation entry.
Cost allocation and charging methodology	The charging framework would require generators to pay an average cost charge for the share of the SENE that they use as a negotiated transmission service. These charges would be set such that customers, on average and over time, would not be expected to face any costs. Customers would be required to pay for any revenue requirement not recovered where fewer generators connect or connect later than was planned for.
Access provisions	The SENE would operate with firm financial rights. Generators would be entitled to compensation if they were constrained off below their agreed power transfer capability (which is set out in the connection offer) and required to pay other generators on the SENE compensation if they were to generate in excess of their agreed power transfer capability.
Regulatory oversight	AEMO would be required to review the relevant NSP's forecast generation profile. New projects would then only go ahead if AEMO approved the forecasts. The AER would be able to veto a proposed connection agreement based on a "reasonableness" test. The inclusion of a cost threshold to trigger the construction of a SENE would act as a further risk mitigation measure designed to protect customers.

8.2.2 Discussion of Option 1

Timely connection

Under Option 1, consideration of a SENE would commence with AEMO's NTNDP consultation process. As part of its NTNDP, AEMO would be required to identify potential SENE zones in the NEM. Based on these zones, NSPs would then be responsible for the preliminary planning (and ultimate implementation) of a SENE. The advantage of this centrally planned type approach to triggering consideration of a SENE is that NSPs could commence preliminary planning ahead of receiving a connection enquiry. This allows for more timely connection of generators.

However, there are risks associated with this approach where AEMO does not have sufficient information to accurately identify SENE zones (for example, because market participants are hesitant to reveal commercially sensitive information, or because of confidentiality provisions that do not allow NSPs to reveal connection enquiries or applications). In addition, concerns have been raised that under this approach, AEMO would have to 'second guess' the market. Where SENEs are limited to zones identified by AEMO, this approach could potentially hinder market driven investment.

The draft SENE Rule intended AEMO to act as a "filter in identifying potentially suitable areas"[134] to minimise this risk. However, there is some tension between AEMO identifying a number of zones and the requirement for NSPs to assess credible options in their APRs for all SENE zones attributed to them.

Efficient locational signals

Option 1 would maintain the principle that generators should face the costs incurred in connecting them to the network. By requiring generators to pay their average proportional cost for use of the SENE, Option 1 would ensure that generators face appropriate locational signals.[135]

LYMMCO[136] and the NGF[137] submitted that this average cost approach would distort locational signals. They consider that an average cost charge would represent a lower charge than generators would face if they were locating elsewhere on the network, and therefore may encourage inefficient connection to the SENE.

The AEMC disagrees that an average cost price would distort locational signals. The purpose of SENEs is to allow for efficient coordinated connections, recognising the difficulties in aligning project timelines and the connection of future generation. In the absence of these coordination and timing challenges, generators would be able to negotiate a shared connection asset for which they would pay a proportional average charge. This concept has been extended to SENEs. The fact that the charge may be lower compared to other connection options represents the gains from efficient coordination (recognising that these gains will only be realised if forecast generation materialises).

Potential to capture scale economies

By requiring customers to underwrite the risk of any under-utilised capacity, Option 1 would also have the advantage of overcoming the lack of incentives on NSPs and generators to bear the risk of building assets to an efficient scale in advance of future connections. In doing so, this option would address the first mover issue by ensuring the first connecting generator does not face a disproportionately large share of the costs

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134 See AEMC 2009, Review of Energy Market Frameworks in light of Climate Change Policies: Final Report, September 2009, Sydney, p.19.

135 Origin Energy indicated its support for the basic charging regime proposed, noting that requiring individual generators to pay for the proportional transmission capacity they use imparts appropriate locational signals. Origin Energy, Consultation Paper submission, p.11.

136 LYMMCO, Consultation Paper submission, pp.4-9.

137 NGF, Consultation Paper submission, pp.20-25.

compared to future connecting generators. Overcoming the first mover disadvantage and allowing more efficient connections would flow through to more efficient electricity prices in the long run, consistent with the NEO.

The size of a SENE, and therefore the potential to capture scale economies, may in practice be limited by congestion on the shared network in proximity to the point where the SENE connects. Under the proposed SENEs framework, NSPs would be required to consider and publish the impact of the SENE on the existing network. However, they would not be required to undertake any network augmentation to relieve congestion. While generators may choose to fund network upgrades[138], the AEMC understands that in practice this rarely occurs due to the free rider problem.[139]

As discussed previously, other options for expanding the capacity of the shared network to realise greater economies on the SENE appear equally problematic. The NSP could assess the market benefits of upgrading the shared network as a prescribed service using the RIT-T, but this would impact on the ability of generators to connect in a timely manner.

Alternatively, the augmentation to the shared network could be treated as a negotiated service being provided as part of the SENE. However, this could significantly increase the charges associated with use of the SENE, providing an incentive for prospective generators to bypass the SENE and connect directly to the network, increasing the stranded asset risk (or more likely, preventing the SENE from materialising).

Complexity of the framework

Option 1 would introduce a complex new framework. As such, this option would require substantial amendments to the Rules and may introduce inconsistencies with existing frameworks. In addition, it would likely prove challenging to implement, notably because of the introduction of compensation arrangements, a new cost recovery mechanism from customers which would sit outside of the TUOS charging arrangements, and a service classification that does not fit neatly into the existing Rules.[140]

Some of the implementation challenges raised in the Consultation Paper include:

- *Alternative configurations:* configurations other than a simple hub and spoke design could present challenges in developing an efficient charging regime.

138 NER clause 5.6.6B.

139 The free rider problem occurs because a generator that funds an augmentation to the shared network cannot prevent others from benefiting from that upgrade or require others to contribute to its cost. Therefore they have limited incentives to undertake such augmentations.

140 Under Option 1, the extension is characterised as providing negotiated transmission services. However, customers underwrite the risks, which is inconsistent with recovery of negotiated transmission charges.

- *Interruptible generation:* Option 1 does not articulate whether generation can connect to the SENE with an agreed power transfer capability of zero and with an agreement to generate only where there is spare capacity on the network.

- *Distinguishing SENEs from the shared network:* the introduction of compensation arrangements introduces the potential for SENEs to be treated differently from the remainder of the network. This becomes problematic where SENEs become difficult to distinguish from the shared network. This could be as a result of the SENE subsequently becoming part of the shared network or, as discussed above, simply because it may be difficult to define which assets form the extension and which are part of the shared network to start with.

The development and management of the compensation mechanism is likely to prove challenging. Under the proposed Rule, the AER would be required to publish a generic marginal cost for identified categories of generating facilities for the purpose of calculating compensation.[141] NSPs would be required to manage the payment transfers between generators. Some stakeholders considered that neither entity is well placed to undertake these roles.[142]

Management of stranded asset risk

The proposed oversight roles of AEMO and the AER should help ensure that any incentives that NSPs or generators may have to inefficiently size the asset are kept in check. Stakeholders generally agreed that these roles were appropriate. However, many considered further measures were necessary to further manage the asset stranding risks.

For this reason, a cost threshold trigger has been included in this option. The impact of this measure would depend to some extent on the level of the cost threshold. As noted in section 6, setting the level too low would not significantly contribute to minimising asset stranding risk, while setting the level too high would risk projects never materialising. However, generally it would provide a greater level of firm commitment from generators and therefore would lower the risk of asset stranding.

141 Proposed SENE Rule clause 5.5A.14(c).

142 The AER considers that AEMO is better placed to prepare and publish marginal cost data. Energy Australia, Ergon Energy and Citipower/Powercor question whether NSPs have the requisite skills to manage the compensation arrangements. See: AER, Consultation Paper submission, p.5; EnergyAustralia, Consultation Paper submission, p.26; Ergon Energy, Consultation Paper submission, p.6; Citipower/Powercor, Consultation Paper submission, p.2.

8.3 Option 2: SENEs with an economic test and no capacity rights

8.3.1 Key design features

Option 2 is also based on the existing proposed SENE frameworks and shares many of the features of Option 1, including a cost threshold trigger. In addition, Option 2 includes an economic test to assess whether a proposed network extension is efficient, further strengthening the investment test to provide additional safeguards for customers. Option 2 also simplifies the proposed framework by removing the explicit compensation arrangements, instead leaving access provisions to be negotiated between the NSP and generators.

These variations are set out in the following table. The other key design features, including the trigger for considering a SENE, the cost allocation and charging methodology and regulatory oversight provisions are the same as in Option 1 above.

Key design feature	Option 2
Investment test	NSPs would consider whether there are likely to be scale efficiencies from building a SENE. In addition, NSPs would be required to explicitly assess the likely market benefits associated with the proposed investment. They would only proceed to developing a connection agreement where net market benefits were found. The economic test would be separate to the existing RIT-T, but would perform a similar function. Unlike the RIT-T, the assessment would only consider the merits of the proposed SENE investment[143]: it would not explicitly consider the merits of any concurrent augmentation to the existing network. However, as under the proposed Rule, NSPs would be required to publish information regarding the likely impact on the existing network. NSPs would be required to forecast generation entry using a market-driven market development model. Details of this analysis would be published in the SENE planning report and would be reviewed by the AER in considering the proposed SENE connection offer. The SENE would still be classified as providing a negotiated transmission service and hence charges would still be recovered from generators. Construction of a SENE would be triggered once an NSP signed connection agreements with generator(s) that cover at least 25 per cent of the capital cost of the SENE. While NSPs would not be prevented from building a SENE that had not reached the trigger, they would not be able to recover any costs from customers until the 25 per cent threshold was met. NSPs would

143 This is because the RIT-T itself would need to be applied for any proposed augmentation to the shared network (assuming applicable thresholds were met).

Key design feature	Option 2
	therefore be exposed to the risk of future generation entry. The SENE would only proceed when both tests have been satisfied i.e. the entire investment passes the investment test and firm generator commitments meet the cost threshold.
Access provisions	Access would be provided as per the shared network. Generators would negotiate directly with NSPs on terms and conditions of access.

8.3.2 Discussion of Option 2

Option 2 has many similar features to Option 1, and so many of the same issues raised above also apply to Option 2. There are two key areas where Option 2 diverges from Option 1.

Stranded asset risk, timely connection and capturing scale economies

Option 2 would require NSPs to undertake an economic assessment that would explicitly measure the market benefits of the investment in addition to the costs. The investment would only proceed where there were demonstrable net market benefits associated with the SENE. The purpose of including such a test would be to provide greater assurance that the investment, which customers would be required to underwrite, was likely to be efficient.

However, introducing an economic test may also introduce risks of delays to connection. This is because applying an explicit test would introduce an additional step into the assessment process. In addition, the test would be open to challenge, which could impact project time scales significantly, particularly where the test is underpinned by an arguably more controversial method for modelling generator entry (arguably, the assumptions underpinning the SENE under Option 1 may be equally controversial). Several of the submissions to the SENEs Rule change Consultation Paper who did not support the inclusion of an efficiency test also raised these as potential issues.[144]

Complexity of the framework and uncertainty

The second key difference between Option 1 and Option 2 is the absence of any explicit compensation arrangements. By leaving these to be negotiated between the NSP and generators, Option 2 would remove a significant layer of complexity from the proposed SENE framework. Arguably, this approach would be more consistent with the existing frameworks. While generators currently tend to have sole use assets, and therefore may have implicit rights to use of those assets, the Rules envisage that those

144 Origin Energy, Consultation Paper submission, p.4; Infigen Energy, Consultation Paper submission, p.4.

assets may be used by future network customers. The cost allocation between an incumbent and a new entrant is subject to negotiation with the NSP.

Further, the issue of access to the transmission network for generators is a key component of the TFR. Mandating compensation arrangements as part of the SENE framework has the potential to create inconsistencies with the outcomes of that Review.

However, leaving compensation arrangements to be negotiated between NSPs and generators may introduce uncertainty for generators. While this is not inconsistent with the current arrangements for the shared network, generators may find it more difficult to obtain financing without guaranteed access.

While Option 2 may provide a simpler arrangement than Option 1, it nevertheless still presents a number of challenges in respect of practical implementation, as discussed in Option 1.

8.4 Option 3: Incremental approach to SENEs

8.4.1 Key design features

Option 3 is based on an approach put forward by Grid Australia[145] whereby the RIT-T would be applied to incremental capacity (and potentially a different configuration) above that required to connect a first generator or group of generators. Subsequent connecting generators would contribute to the stand alone cost of the first generator(s), and the cost of any incremental capacity justified by the RIT-T would be met by customers. These features are described in the table below.

Key design feature	Option 3
Trigger for considering a SENE	A generator (or group of generators) connection enquiry[146] would trigger consideration of whether building capacity in excess of that generator's requirements would be efficient. Where the initial generator(s) agrees, the NSP would then decide whether to consider a higher capacity extension (and/or a different route/configuration), which would accommodate the connection of additional generators in the same area.
Investment test	The RIT-T would be applied to the capacity beyond the requirements of a first connecting generator(s) to determine whether building that additional capacity would provide net market benefits (this requires that the first generator would be willing to pay their stand alone cost, as discussed below). The costs of the RIT-T would be borne by either:

145 Grid Australia, Consultation Paper supplementary submission, 4 August 2010.

146 Given the relatively small scale of some of the new generation that may seek connection, there is a possibility that some connection enquiries, at least initially, may go to DNSPs. This option may therefore require a mechanism to ensure that, where appropriate, such connection enquiries may be referred to the relevant TNSP.

Key design feature	Option 3
	• the initial generator, on the basis that it might benefit from scale economies; and/or • prospective generators who may wish to connect in future. The RIT-T assessment would also take into account any need for broader network augmentation.
Cost allocation and charging methodology	The initial generator(s) would be required to pay a charge based on its stand alone cost. This would be partially rebated over time as other generators connect. The charge would relate to a negotiated transmission service. Customers would be required to permanently fund the incremental capacity above that required to connect the first generator i.e. to the portion of the SENE that passed the RIT-T. This part of the SENE would be classified as providing a prescribed transmission service. The cost of any augmentation to the shared network would also be met by customers (noting that it would have passed the RIT-T). The incremental portion of the SENE would likely be included in a TNSP's revenue determination as a contingent project. However, as a transitory arrangement, a pass-through mechanism may be required where such investments were not included in the previous revenue determination.
Access provisions	Access would be provided as per the shared network, i.e. no compensation arrangements would apply.
Regulatory oversight	Grid Australia notes that AEMO would retain the role it currently has in relation to the application of the RIT-T by TNSPs, such as providing independent input via the NTNDP. The AEMC considers that, in addition, the AER should be required to review the NSP's application of the RIT-T. Further, AEMO should be required to undertake a review of the relevant NSP's forecast generation profile.

8.4.2 Discussion of Option 3

Timely connection

Option 3 would require the RIT-T to be applied to the incremental capacity above and beyond the requirements of the first connecting generator(s). As discussed previously, the RIT-T process takes at least seventeen months from the issuance of the project specification consultation report, and potentially over two years if the NSP's conclusions are disputed. While applying the RIT-T only to incremental capacity may limit the scope of credible options, there is nonetheless a risk to the timely connection of generation due to the test being open to challenge. The longer such disputes take to resolve, the greater the chance that the opportunity for coordination will dissipate.[147]

Unlike Options 1 and 2, the identification of zones under Option 3 would be driven by market entry rather than by AEMO. This would ensure that SENEs are considered in areas where there is demonstrated market interest. However, it would also limit the scope for preliminary planning.

Efficient locational signals

Under Option 3, the charging arrangements would require the first connecting generator (or group of generators) to pay their stand alone cost. Grid Australia considers that this would provide appropriate locational signals. However, generators who subsequently connect to the extension would then be charged a portion of the first generator's stand alone cost. Arguably, this may distort locational signals for future connecting generators as their charges would not reflect their use of the SENE. Further, it could encourage inefficient connection to the SENE and a competitive advantage since generators would face significantly reduced charges. For this reason, the AEMC has also put forward a variation of Option 3 which has alternative cost recovery arrangements.

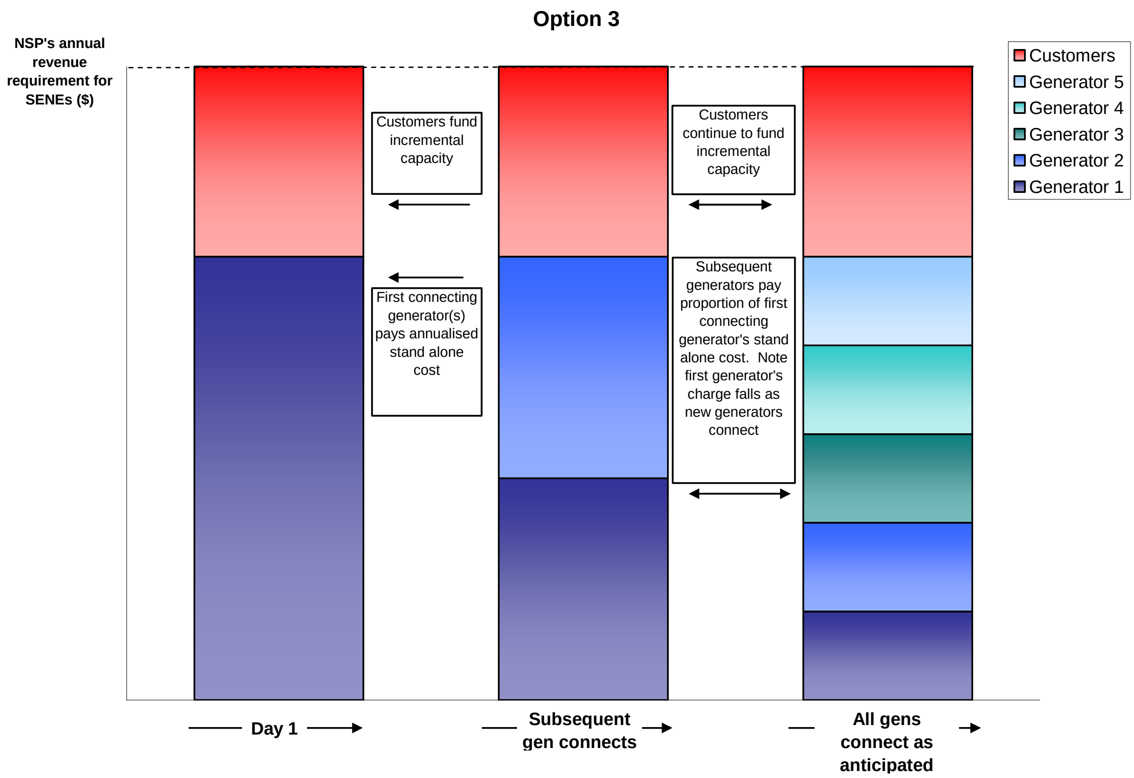
Grid Australia's approach is, however, consistent with the MCE's consideration that where net market benefits are demonstrated, all or part of the SENE might permanently be funded by customers.

The diagram below is for illustrative purposes only and is intended to highlight the cost recovery arrangements set out under Option 3. Consideration would need to be given to how the first generator's costs would fall over time as each new generator connects and the profile of charges to subsequent connecting generators. For illustrative purposes we have assumed that the first connecting generator's charge would halve when a second generator connects. Similarly, as a third generator connects, the charges of both the first and second generators would reduce, such that each pays one third of the first generator's stand alone cost.[148]

147 This issue of timeliness of connection only applies to the first connecting generator(s), prior to the SENE being built. Once the SENE is built, it will provide for more timely connection to future generators.

148 This assumes that each generator has the same level of agreed power transfer capability.

Figure 8.1[149]



Potential to capture scale economies

By allowing incremental capacity to be built in anticipation for future generator connection, Option 3 would likely provide some efficiency gains. However, Option 3 does not address the first mover issue and, as such, any efficiency gains would be limited to circumstances where the first generator is both able and willing to pay its stand alone cost.

Some first mover generators may be dissuaded from agreeing to a SENE rather than sole-use assets since the approval of the stand alone project would be faster and charges for future generators would be negotiated on a confidential basis. Therefore, the first generator would not be privy to the relevant charges being levied on future generators and thus would not be able to ensure that the charges were commensurate with their own. This issue could possibly be addressed in the connection agreement between the NSP and the first generator(s).

Unlike Options 1 and 2, Option 3 provides a clear solution to the issue of the interaction with the shared network in that any potential augmentation would be assessed through the application of the RIT-T.

149 This diagram is for illustrative purposes only. The NSP's annual revenue requirement to be recovered from customers would depend on the amount of spare capacity on the SENE and could be a higher or lower proportion than that shown. Similarly, the charging arrangements for subsequent connecting generators could differ from that assumed.

Complexity of the framework

A key advantage of Option 3 is that the approach would be generally consistent with the existing framework and, as such, would not require major changes to the Rules in order to be implemented. Further clarity could be provided on the links between the RIT-T, classifying an asset as providing a prescribed transmission service and the subsequent cost recovery arrangements in the context of SENEs.

In addition, it would be more straightforward to subsequently subsume the extension into the shared network, if required. However, consideration would need to be given to a mechanism for determining whether the portion of the SENE funded by generators should be reclassified as a prescribed transmission service such that generators would no longer pay a SENE charge, for example, if load connects.

Management of stranded asset risk

Finally, Option 3 would require customers to pay for additional spare capacity to connect future generators where this incremental investment has been justified by the RIT-T. However, the application of the RIT-T would ensure that costs are only recovered from customers where net market benefits have been demonstrated. While this will not protect customers from the risk of asset stranding, it provides a test consistent with the current arrangements to provide assurance that, based on the information available at the time, the investment is likely to be efficient.

8.5 Option 4: Incremental approach with generators bearing the costs

8.5.1 Key design features

Option 4 is based on Grid Australia's proposed approach, but adopts alternative cost allocation arrangements. Under this approach, the first connecting generator(s) would continue to face their stand alone cost, at least initially, and customers would continue to supplement the NSP's revenue requirements while spare capacity remained on the SENE.

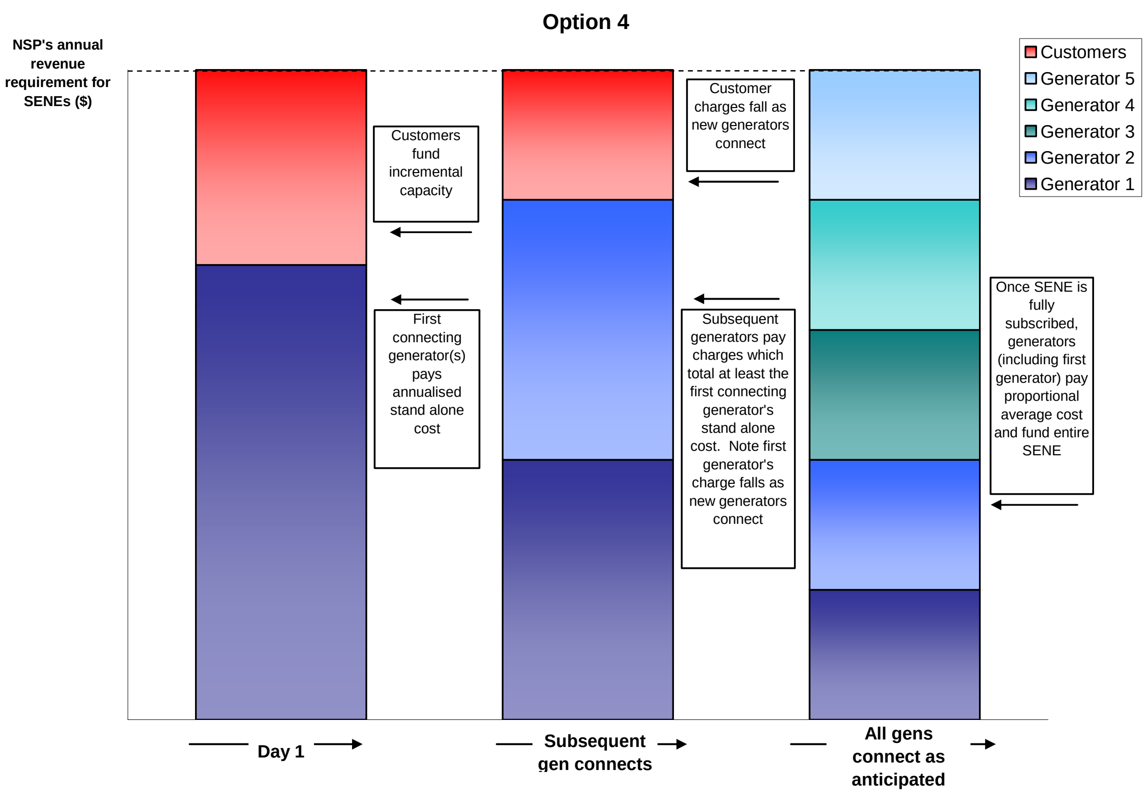
However, the charges faced by both the first connecting generator and customers would reduce as new generators connected. Over the life of the asset, if generation materialised as forecast, generators would be expected to pay their proportional average cost. This would be facilitated by treating the entire connection as a negotiated transmission service, unlike Option 3.

Key design feature	Option 4
Cost allocation and charging methodology	The initial generator(s) would be required to pay a charge based on its stand alone cost. This would be rebated over time as other generators connect. Customers would be required to fund the incremental capacity above that required to connect the first generator i.e. to the portion of the SENE that passed the RIT-T. This would be rebated over time as other generators connect. If all generators connect as anticipated, generators would pay their proportional average cost for use of the SENE. The cost of any augmentation to the shared network would also be met by customers (noting that it would have passed the RIT-T).

8.5.2 Discussion of Option 4

Option 4 only diverges from Option 3 in its cost recovery arrangements. The diagram below is for illustrative purposes and is intended to highlight the cost recovery arrangements under Option 4.

Figure 8.2[150]



150 This diagram is for illustrative purposes only. The NSP's annual revenue requirement to be recovered from customers would depend on the amount of spare capacity on the SENE and could be a higher or lower proportion than that shown. Similarly, the charging arrangements for subsequent connecting generators could differ from that assumed.

Instead of requiring customers to permanently fund the incremental capacity, this option would maintain the principle underpinning the proposed SENE framework that generators should pay for the SENE. Therefore, as subsequent generators connect, costs recovered from both the first generator(s) and customers would reduce over time. Once all anticipated generation connects, all generators would face their proportional average charge, thereby funding the entire SENE. As each new generator connects, they would be required to pay a charge somewhere between their proportional average cost and some amount such that, in total, the stand alone cost of the first connecting generator(s) is still recovered from charges to generators.

The intention behind this approach is to maintain appropriate locational signals for generators that connect to the SENE.

This would add an additional layer of complexity compared to Option 3 in order to implement the cost recovery arrangements. For example, consideration would need to be given to what charges the subsequent connecting generators would face and the profile of rebates to both generators and customers.

Further, as under Options 1 and 2, an alternative mechanism that sits outside the existing TUOS charging arrangements would be required to recover costs from customers to fund any capacity that is unused in advance of later connecting generators.

8.6 Option 5: SENEs as shared network with generator charge

8.6.1 Key design features

Option 5 would maintain the principle that generators should face the costs incurred in connecting them to the network. However, instead of recovering this as a negotiated transmission service, the SENE would be included in the RAB and a new type of prescribed transmission service would be introduced that would be paid for by generators.[151] This prescribed transmission service charge would relate only to the SENE: as per the existing arrangements, generators would not face a charge for use of the existing shared network, nor would they be required to fund augmentations to the shared network.[152] Customers would still underwrite the cost of any spare capacity.

This option is described below.

151 EnergyAustralia has suggested a similar charging regime, however only the proportion to be initially recovered from customers enters the RAB. The initial generator contributes up front to the construction of the SENE based on its proportional use of the capacity. As new generators connect, they pay a proportional contribution to the extension, reducing the value of the RAB. See EnergyAustralia, Consultation Paper submission, p.11.

152 As discussed in section 2, any changes to the existing arrangements for the shared network will be considered as part of the TFR.

Key design feature	Option 5
Trigger for considering a SENE	A generator (or group of generators) connection enquiry would trigger consideration by the NSP of whether building capacity in excess of that generator's requirements would be efficient.
Investment test	A RIT-T would be applied to the entire proposed investment to determine whether building the SENE would provide net market benefits. The generator would be required to fund the RIT-T. The generator would have an incentive to do so on the basis that, if it passes, it would pay its average cost instead of stand alone cost.[153]
Cost allocation and charging methodology	Shared connections, including SENEs, would need to be carefully defined, such as all elements of transmission network spurs shared by more than one party but which are not required to support DNSP load. These assets would support a new type of prescribed transmission service, for which generators would be charged their proportional average cost for use of the SENE from the time they connect. As under the existing framework, generators connecting to the SENE would not face a charge for their use of the existing shared network and would not be required to fund any augmentation to the shared network (although they may choose to do so). Such investments would generally be included in a TNSP's revenue determination as a contingent project. However, as a transitory arrangement, a pass-through mechanism may be required where SENEs were not included in the previous revenue determination. As a prescribed service, the costs associated with the SENE would enter a TNSP's regulatory asset base[154] and be recovered as part of its maximum allowed revenue. As new entities connect, they would face a proportional average charge. Any spare capacity on the SENE would automatically be recovered from customers through TUOS. While customers would therefore face some costs associated with the SENE, these costs would reduce over time as generators and other network customers connected.
Access provisions	Access would be provided as per the shared network.
Regulatory oversight	The AER would be required to review the NSP's application of the RIT-T. AEMO would be required to undertake a review of the relevant NSP's forecast generation profile.

153 Requiring generators to fund the RIT-T also acts to prevent spurious requests by generators for TNSPs to consider building additional capacity.

154 A number of stakeholders considered that costs recovered from customers should be spread across all customers in the NEM, rather than those in the region in which a SENE is built. The AEMC is currently considering a Rule change request for the inter-regional charging of transmission. Under this proposed Rule change, transmission businesses in each region would levy a load export charge on transmission businesses in adjoining regions, based on the flow of electricity from one region to another. Therefore, if SENE charges to customers were to enter the RAB (and if the proposed inter-regional transmission charging Rule is made by the AEMC), a proportion of these charges would automatically be recovered from neighbouring regions where there were net flows to those neighbouring regions.

8.6.2 Discussion of Option 5

Timely connections

Under Option 5, a RIT-T would be triggered when a generator enquiry is received and an NSP considers that future generator entry in the area is likely. As noted under Option 3, while this approach would necessarily limit the extent to which NSPs could commence preliminary planning early on, it nonetheless ensures a market driven approach.

A key feature of Option 5 is the requirement to apply the RIT-T to an entire proposed network extension. The RIT-T would determine whether building the entire SENE would provide net market benefits. However, as noted previously, the RIT-T process can potentially take up to two years where an NSP's conclusions are challenged. This option therefore carries the risk of potentially significant delays to connections.

As previously discussed, it may be difficult to narrow the scope of the base case and alternative credible scenarios. To implement Option 5 it may therefore be necessary to ensure that the scope was limited. Conceptually, this could be done by locking in the first enquiring generator(s) as committed. However, we understand that this would not happen in practice under the existing Rules.

Efficient locational signals

Option 5 provides for generators to be charged their proportional average cost for use of the SENE from the time they connect. Like Options 1 and 2, the principle that generators should pay for the assets that are required to connect them to the network, is maintained under Option 5. However, compared to those options, this charge would be a simplified charge such that generators would pay only their proportional average cost. Where there was spare capacity, customers would face that charge. Customers would therefore be expected to face a positive cost over the life of the asset. This is justified by the inclusion of the RIT-T which will assess the net benefits to the customer.

This approach would reduce the flexibility of generators to negotiate aspects of their charges. For example, under the proposed framework, with services classified as negotiated, generators would be able to negotiate who bears the risk of cost overruns. Some generators may prefer to have more stable charges, and so are prepared to pay TNSPs a higher return to reduce their own risk. However, if charges are prescribed, there is no scope for such negotiations.

Potential to capture scale economies

By allowing capacity to be built in anticipation of future generator connection, Option 5 would enable scale efficiencies associated with larger network extensions to be captured. However, as noted in the context of Option 3, applying the RIT-T to extensions may result in a project not satisfying the RIT-T, even where there is potential for scale efficiencies. Alternatively, an extension may satisfy the RIT-T and yet there may be no commercial interest. Adopting a market-driven market development model to forecast future generation entry would likely minimise this risk.

However, use of the RIT-T would remove the difficulties associated with interaction with the shared network that are present in Options 1 and 2. Because the SENE is being provided as a prescribed transmission service under Option 5, the extension and any augmentation of the existing shared network are assessed holistically under one process.

Complexity of the framework

A key advantage of Option 5 is the relative simplicity of the proposed arrangements in that a SENE would be classified as part of the shared network and would provide prescribed transmission services, albeit with a new type of prescribed transmission charge for generators. Classifying a SENE in this way would remove the complexities associated with how to distinguish the SENE from the shared network, both now and in the future, and compensation arrangements (access would be as per the shared network). The cost recovery arrangements for unused portions of the SENE would also be simpler than under Options 1, 2 and 4, although customers would be expected to face a positive cost over the life of the asset.

The key change to existing frameworks required would be the need to determine and levy charges for use of the shared connection. This would need to be carefully defined to distinguish the shared network services for which generators would face a charge, such as all elements of transmission network spurs shared by more than one party but which are not required to support DNSP load. Once the asset no longer met this definition, it would be subsumed into the broader shared network and generators would no longer be required to pay the prescribed transmission charge for the shared connection service. Charging on this basis would be consistent with the current approach where connections used only by generators are charged on a 'causer pays' basis.

Management of stranded asset risk

Under Option 5, customers would continue to bear the risk that forecast generation does not materialise. To help mitigate this risk, the AER would be required to review the NSP's application of the RIT-T and AEMO would review the NSP's generation forecasts. However, unlike the original proposed SENE Rule change, customers would not be rebated once subsequent generators connect, that is, they would be expected to face a positive charge. However, as noted above, this is justified because the SENE would be demonstrated to have net market benefits.

9 Lodging a submission

Submissions are to be lodged online or by mail by 12 November 2010 in accordance with the following requirements.

Where practicable, submissions should be prepared in accordance with the Commission's Guidelines for making written submissions on Rule change proposals.[155] The Commission publishes all submissions on its website subject to a claim of confidentiality.

All enquiries on this project should be addressed to Elisabeth Ross or Chris Spangaro on (02) 8296 7800.

9.1 Lodging a submission electronically

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code "ERC0100". The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within three business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

9.2 Lodging a submission by mail

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission should be sent by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235
Or by Fax to (02) 8296 7899.

The envelope must be clearly marked with the project reference code: ERC0100.

Except in circumstances where the submission has been received electronically, upon receipt of the hardcopy submission the Commission will issue a confirmation letter.

If this confirmation letter is not received within three business days, it is the submitter's responsibility to ensure successful delivery of the submission has occurred.

155 This guideline is available on the Commission’s website.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australia Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
Commission	See AEMC
CPRS	Carbon Pollution Reduction Scheme
DNSP	Distribution Network Service Provider
Final Report	Final Report of the Review of Energy Market Frameworks in light of Climate Change Policies
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERA	NERA Economic Consulting
NSP	Network Service Provider
NTNDP	National Transmission Network Development Plan
REC	Renewable Energy Certificate
RET	Renewable Energy Target
RIT-T	Regulatory Investment Test for Transmission
Rules	See NER
SENE	Scale Efficient Network Extensions
TFR	Transmission Frameworks Review
TNSP	Transmission Network Service Provider

A Glossary

The terms defined in this glossary are NER definitions and the italicised terms are defined in the NER.

augmentation	Augmentation of a transmission or distribution system means work to enlarge the system or to increase its capacity to transmit or distribute electricity.
connect, connected, connection	To form a physical link to or through a *transmission network* or *distribution network*.
connection assets	Those components of a *transmission* or *distribution system* which are used to provide connection services.
connection point	the agreed point of *supply* established between *Network Service Provider(s)* and another *Registered Participant, Non-Registered Customer* or *franchise customer*.
connection service	An *entry service* (being a service provided to serve a *Generator* or a group of *Generators*, or a *Network Service Provider* or a group of *Network Service Providers*, at a single *connection point*) or an *exit service* (being a service provided to serve a *Transmission Customer* or *Distribution Customer* or a group of *Transmission Customers* or *Distribution Customers*, or a *Network Service Provider* or a group of *Network Service Providers*, at a *single connection point*).
extension	an *augmentation* that requires the *connection* of a power line or *facility* outside the present boundaries of the *transmission* or *distribution network* owned, controlled or operated by a *Network Service Provider*.
identified need	The reason why the *Transmission Network Service Provider* proposes that a particular investment be undertaken in respect of its *transmission network*.
national grid	The sum of all *connected transmission systems* and *distribution systems* within the *participating jurisdictions*.
negotiated transmission service	Any of the following services: (a) a *shared transmission service* that: (1) exceeds the *network* performance requirements (whether as to quality or quantity) (if any) as that *shared transmission service* is required to meet under any *jurisdictional electricity legislation*; or (2) except to the extent that the *network* performance requirements which that *shared transmission service* is required to meet are prescribed under any *jurisdictional electricity legislation*, exceeds or does not meet the *network* performance requirements (whether as to quality or quantity) as are set out in schedule 5.1a or 5.1; (b) *connection services* that are provided to serve a *Transmission Network User*, or group of *Transmission Network Users*, at a

	single *transmission network connection point*, other than *connection services* that are provided by one *Network Service Provider* to another *Network Service Provider* to *connect* their *networks* where neither of the *Network Service Providers* is a *Market Network Service Provider*; or (c) *use of system services* provided to a *Transmission Network User* and referred to in rule 5.4A(f)(3) in relation to *augmentations* or *extensions* required to be undertaken on a *transmission network* as described in rule 5.4A, but does not include an a*bove-standard system shared transmission service* or a *market network service*.
non-regulated transmission services	A *transmission service* that is neither a *prescribed transmission service* nor a *negotiated transmission service*.
prescribed transmission service	Any of the following services: (a) a s*hared transmission service* that: (1) does not exceed such *network* performance requirements (whether as to quality or quantity) as that *shared transmission service* is required to meet under any *jurisdictional electricity legislation*; (2) except to the extent that the *network* performance requirements which that *shared transmission service* is required to meet are prescribed under any *jurisdictional electricity legislation*, does not exceed such *network* performance requirements (whether as to quality or quantity) as are set out in schedule 5.1a or 5.1; or (3) is an *above-standard system shared transmission service*; (b) services that are required to be provided by a *Transmission Network Service Provider* under the Rules, or in accordance with *jurisdictional electricity legislation*, to the extent such services relate to the provision of the services referred to in paragraph (a), including such of those services as are: (1) required by *AEMO* to be provided under the *Rules*; and (2) necessary to ensure the integrity of a *transmission network*, including through the maintenance of *power system security* and assisting in the planning of the *power system*; or (c) *connection services* that are provided by a *Transmission Network Service Provider* to another *Network Service Provider* to *connect* their *networks* where neither of the *Network Service Providers* is a *Market Network Service Provider*; but does not include a negotiated transmission service or a market network service.
system-wide benefits	Benefits that extend beyond a *Transmission Network User*, or group of *Transmission Network Users,* at a single *transmission connection point* to other *Transmission Network Users*.

transmission network	A *network* within any *participating jurisdiction* operating at nominal *voltages* of 220 kV and above plus: (a) any part of a *network* operating at nominal *voltages* between 66 kV and 220 kV that operates in parallel to and provides support to the higher voltage *transmission network*; (b) any part of a *network* operating at nominal *voltages* between 66 kV and 220 kV that is not referred to in paragraph (a) but is deemed by the *AER* to be part of the *transmission network*.
Transmission Network Users	In relation to a *transmission network*, a *Transmission Customer*, a *Generator* whose *generating unit* is directly *connected* to the *transmission network* or a *Network Service Provider* whose *network* is *connected* to the *transmission network*.
transmission service	The services provided by means of, or in connection with, a *transmission system*.
transmission system	A *transmission network*, together with the *connection assets* associated with the *transmission network*, which is connected to another *transmission or distribution system*.
use of system services	*Transmission use of system service* and *distribution use of system service.*

B Comparison of the SENE and RIT-T investment ‘tests’

This appendix describes:

- how the SENE test is intended to be used to assess whether a SENE should proceed (including the scale of the SENE);
- how the RIT-T could operate to assess whether a SENE should proceed (including the scale of the SENE); and
- where the two tests would require similar analysis and deliver similar results, and where the analysis and results may differ.

B.1 Applying the 'SENE test'

The ‘test’ for deciding whether a SENE should proceed that was described in the Final Report of the Review of Energy Market Frameworks in light of Climate Change Policies[156] mirrors the treatment of connection assets, namely that the project should proceed if there is sufficient demand for the asset. It was not intended that there would be an inquiry about whether generation entry at that location and time would be efficient.

More specifically, the test was intended to operate as follows:

- First, establish the level of demand for the SENE asset on the assumption that the users of the asset would pay prices that are expected to recover the full cost of the asset. This may require a number of scenarios if the likely level of demand is sensitive to the price that is charged.
- Secondly, determine the asset that is the most efficient means of meeting the forecast demand for the asset, considering both the cost of building a larger asset now (with holding costs) compared to building a second asset in the future as well as the potential to stage the construction of the asset to minimise stranded asset risk (that is, to factor in real options).

The difference between the SENE test and the normal process whereby connection assets are constructed is how demand for the asset is established. Connection assets are only undertaken once the generator or generators have entered into a contract under which the whole cost of the connection would be recovered, which establishes the demand for the asset. In contrast, while some of the costs of a SENE would be recovered under contracts that are signed prior to the connection asset being constructed, part of the cost would be recovered from generators who would be forecast to use the SENE (and pay the appropriate charge) in the future.

156 AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Final Report*, September 2009, Sydney, Chapter 2.

Deriving a forecast of the future (generation) use of a SENE is not straightforward. As generators all supply into the same market (at least when the transmission network is unconstrained), entry at one point will affect spot and contract prices and lessen the incentive for entry at another location. Similarly, a model of renewable plant entry would be required which took account of the impact of renewable entry at one point on the price of Renewable Energy Certificates (RECs) and hence the incentive for further renewables entry. Thus, forecasting the future (generation) use of a SENE would require a forecast of future generation entry across the NEM (and, as RECs would be traded nationally, potentially also across Australia).

B.2 Applying the RIT-T

The RIT-T is an economic cost benefit test that has been applied to the specific case of investigating the need for electricity transmission projects.[157] A key design feature of the test is that wealth transfers between individual market participants are ignored and instead the focus is upon the costs and benefits that accrue to society as a whole.[158]

The costs and benefits that may be associated with a transmission project include:

- the cost of the relevant transmission projects that are being investigated;
- the change in the short run generation cost – a new transmission investment may relieve a constraint and thus permit the greater use of a low cost generator;
- the change in long run generation cost – a new transmission investment may relieve a constraint that permits better use of existing generation (and a deferral of generation investment) or that induces more generation entry at a low cost location. This will include connection costs borne by generators;
- the change in network losses – a new transmission investment may reduce or raise network losses; and
- the change in system reliability – a new transmission investment may reduce or increase the overall reliability of supply to final customers.

These costs or benefits may accrue to various participants or stakeholders in the electricity supply chain, and some individually may be made better or worse off as a result of the transmission investment. The RIT-T, however, ignores the distribution of the costs and benefits and focuses on the aggregate across all participants and stakeholders.

157 The Rules require the AER to promulgate the RIT-T and associated guidelines and sets out the required elements for the test (NER clause 5.6.5). The AER has promulgated the RIT-T (AER 2010, *Regulatory Investment Test for Transmission*, June 2010) and Guidelines (AER 2010, *Regulatory Investment Test for Transmission Guidelines*, June 2010).

158 Note, however, that there are constraints to the economic costs and benefits that may be considered. The RIT-T requires the benefits and costs to be restricted to those that accrue to participants/customers in their role as electricity participants/customers and so excludes wider externalities (such as the cost of greenhouse gas emissions while they remain unpriced).

Applying the RIT-T therefore also requires a number of modelling tasks, including:

- a model of how a transmission project will change future generation dispatch (to derive the change in short run generation costs);
- a model of how a transmission project will change future generation investment decisions (to derive the change in long run generation costs);
- a model of how network losses will change as a result of the change in future network flows resulting from the new transmission asset, change in generation dispatch and change in generation investment; and
- a model of how reliability across the generation and transmission supply chain will change as a result of the new transmission asset and its consequent impact upon generation dispatch and future generation investment.

For the assessment of a SENE, the most important benefit to measure is the projected change in future generation investment that results from the SENE. This is because the benefits of more efficiently coordinating connection will only be realised where generators connect to the SENE.

B.3 The SENE test and RIT-T compared

There are many similarities between the SENE test and the RIT-T when assessing whether a SENE should proceed.

The key requirement for assessing either the profitability of SENE connected generation (as required by the SENE test) or the efficiency of the SENE connected generation (as required by the RIT-T) is to forecast the amount of generation that would use the SENE if the SENE is constructed and displace generation entry elsewhere in the NEM (and renewable entry elsewhere in Australia). Indeed, SENEs are intended to overcome any first mover disadvantage to allow new generation investment that is lower cost or that delivers greater profit than might have occurred in the absence of the SENE.

There are two key areas where the analysis under the SENE test and RIT-T may differ, which are:

- the forecast effect of the SENE on future generation entry; and
- for a given forecast of future generation entry, how the 'worth' of that change in generation entry is calculated.

These are discussed in turn.

B.3.1 Forecasts of future generation entry

As discussed above, applying the RIT-T to evaluate the worth of a SENE requires, amongst other things:

- a forecast of the generation entry that would have occurred in the NEM in the absence of the SENE; and then
- a forecast of the generation entry in the NEM with the SENE.

Whether the SENE is efficient then depends upon whether the SENE would create a net benefit, including whether the SENE would induce a reduction in the cost of generation that more than outweighs the cost of the SENE.[159] A similar step is also required to apply the SENE test – that is, a forecast is required of the future use of the SENE, which in turn also requires an assumption about the alternative generation entry projects.

It should be the case that both the SENE test and the RIT-T would employ the same forecasts of generator use of the SENE (and also, implicitly, an identical forecast of the generation that is redirected from other parts of the NEM). However, this need not be the case.

The RIT-T defines two methods for forecasting future generation entry with and without a particular project in place, which are referred to as 'least-cost market development modelling' and 'market-driven market development modelling'. These are defined as follows[160]:

> "Least-cost market development modelling derives modelled projects on the basis of a least-cost planning approach akin to conventional central planning. The modelled projects derived from such an approach would be those where the net present value of benefits, such as fuel substitution and reliability increases, exceed the costs, subject to meeting any minimum reserve requirements.
>
> Market-driven market development modelling derives modelled projects on the same basis as that of a private developer. The modelled projects derived from such an approach would be those where the net present value of generation revenues (from the spot market or contracts) exceeds the net present value of generation costs. The forecasts of price trends should reflect realistic bidding behaviour, with power flows to be those most likely to occur under actual systems and market outcomes. "

159 The RIT-T follows the standard approach in cost benefit analysis (and many other types of economic analysis) and requires a comparison of the 'state of the world' with the relevant project in place to the 'state of the world' without the relevant project in place. The net market benefits associated with a particular project are estimated by comparing certain outcomes that are observed in each of the states of the world (that is, capital and operating expenditure, reliability and system losses). Part of each 'state of the world' is a forecast of future generation entry, as the AER explains in the RIT-T Guideline: 'Beyond taking account of existing assets and facilities, to fully describe a state of the world, a TNSP must derive appropriate committed, anticipated and modelled projects — that is the future evolution of and investment in generation, network and load. Committed, anticipated and modelled projects are defined in the RIT-T.' AER 2010, *Regulatory Investment Test for Transmission Guidelines*, June 2010, p.16.

160 AER 2010, *Regulatory Investment Test for Transmission*, June 2010, clause 21.

The RIT-T *requires* generation entry to be forecast using least-cost market development modelling, but *permits* market-driven market development modelling also to be undertaken where appropriate.[161] This means that in cases where market-driven market development modelling is deemed to be appropriate, two forecasts of future generation entry would be produced. The AER has clarified in the RIT-T Guideline that its intention is that 'market-driven market development modelling' would only be applied as a 'sensitivity'.[162] In contrast, the SENE test should be applied by forecasting the actual use of the SENE, and implicitly therefore the actual shift in generation from other parts of the NEM, which corresponds to market-driven market development modelling.

The correct forecasting technique in principle is the 'market-driven market development modelling' for both the SENE test and RIT-T, given that it is the impact upon actual generation entry that will the future profitable use of the SENE as well as the efficiency benefits created. This is not inconsistent with the AER's discussion, where it justifies requiring the use of least-cost market development modelling not on the basis that it is more accurate than market-driven market development modelling, but rather that it more administratively feasible to apply[163]:

> "The reason why least-cost market development modelling must be undertaken is that it relies on relatively uncontroversial assumptions and methodologies (derived from operations research), whereas market-driven market development modelling may be strongly influenced by assumptions regarding plant bidding behaviour and ownership."

The potential exists for the forecast actual future generation entry – and the impact of a SENE on that pattern of entry – to be different to a projection of the least cost future generation entry. The signals that are provided by the energy market are not perfect, and neither are the signals to generators about the costs that they cause on the transmission network. In addition, factors may exist that have a material impact on generation entry but are not easily captured in a least-cost model, with examples being the degree of policy certainty over carbon pricing and the impact of the global financial crisis on access to investment funds.

The error from using the least-cost market development modelling may go in both directions and lead to:

- a SENE being constructed to the scale dictated by least-cost entry, but the generation nonetheless locating elsewhere or later; or
- a SENE not being built or being built to a smaller scale but generation nonetheless being constructed in even higher cost locations.

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161 AER 2010, *Regulatory Investment Test for Transmission*, June 2010, clause 21.

162 AER 2010, *Regulatory Investment Test for Transmission Guidelines*, June 2010, p.17.

163 Ibid.

For most applications of the RIT-T, applying the easier and less controversial method for forecasting future patterns of generation entry is justified given that generation entry related market benefits are typically a very small component of the overall market benefit for a project. However, given that the dominant benefit created by SENE project will be its impact on generation entry, it is justifiable to place greater weight on forecasts of actual future generation entry.

B.3.2 Generation profitability vs. efficiency

If the market-driven market development modelling method is used to derive the forecasts of future generation entry with and without the SENE, then the distinction between the SENE test and RIT-T can be summarised as:

- the SENE test asks whether the use of the SENE is more profitable (that is, delivers a higher net private benefit) for a generator than locating elsewhere; and
- the RIT-T asks whether it is more efficient for a generator to connect and use the SENE than to locate elsewhere (that is, delivers a higher net market benefit).

In many cases, these tests would be expected to provide similar answers.

The simplest case would occur where a SENE connected generator is expected to displace identical generation that otherwise would have located elsewhere. For example, the generator may be attracted to use the SENE because better quality wind resources existed in the region of the SENE, thus permitting the same output to be provided with fewer wind turbines and therefore at lower cost. As the SENE only induced a change in the location of the wind generator, other factors like system reliability are likely to be unchanged. Thus comparing the tests:

- For the generator to agree to connect to the SENE and pay a usage charge, it must be the case that the cost saving it makes from gaining access to the better quality wind resource exceeds the cost of using the SENE.
- If the impact on the shared network is ignored, then the fact that there is a net cost saving to the generator from locating on the SENE means that an economic benefit would also follow. Indeed, the economic benefit from constructing a larger SENE to accommodate an additional generator is likely to be higher than the increase in profitability (and so the RIT-T may justify a larger SENE than would the SENE test). This follows because the private cost borne by the last generator for using the SENE – which is proposed to reflect the average cost – is likely to exceed the cost to society of building that additional capacity (which is the incremental cost).

A material difference in the outcomes of the SENE test and RIT-T may emerge if the SENE connected generation is expected to have a more substantial impact upon future shared network investment than generation that connects elsewhere. The source of the problem is the fact that generators do not pay for the use of the shared network and hence are not exposed to the costs that they may cause. That is, if the SENE connected generation is expected to cause more cost on the shared network then it is possible that a SENE project may be privately profitable but socially inefficient. This is best illustrated with a simple example:

> Assume that the private and social benefit from a generator is \$100, the cost of the generator is \$20, the cost of the SENE is \$60 and the cost of the shared transmission augmentation required for the export of the energy is \$30. If the generator is confident that the transmission augmentation will occur – but knows that it will not pay for it – then it will calculate its expected profit as \$100-\$20-60=\$20. Once the generator is in place its cost is sunk and so the net market benefit from the augmentation to the shared transmission network is \$100-\$60-\$30=\$10, and so it will proceed. However, if the whole of the project had been evaluated as a single project (as would be the correct thing to do) then the net benefit would be evaluated as \$100-\$20-\$60-\$30=-\$10 and the project would have been judged as inefficient.

While this problem is one that applies generally across the NEM, the problem may be more marked for the case of a SENE given that the scale of the SENE may be such that shared network augmentations are undertaken immediately in parallel to the SENE development. In this situation, the RIT-T would provide the better guidance for whether the SENE should proceed. It may also be possible to apply the RIT-T to the combined SENE and shared network project.

Where the SENE creates a change to the timing or type of generation (rather than just its location) then there is more scope for the SENE test and RIT-T to deliver different outcomes regarding the worth of a SENE. As the SENE test will factor in the private costs and benefits to generators, whether the tests deliver the same answer turns on the accuracy with which the energy market accurately signals the costs and benefits to society of generation at any point in time. This includes that energy prices accurately signal the value of customer reliability, which would mean that if the SENE encourages less reliable plant to be constructed, that the generator’s expected revenue (and therefore its profitability) will mirror the lower value of that plant from society’s perspective.