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Case Study of the Network Extension - Public Report

Grid Australia

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1. Introduction

This report sets out the findings of the case study analysis of an extension of the transmission network to connect new sources of generation remote from the existing network. The case study is illustrative in nature and is based on an extension of the network to connect wind generation in the Eyre Peninsula region, South Australia. The case study has been undertaken in the context of the Rule change process currently being undertaken by the AEMC, in response to the MCE's Rule Change Request – Scale Efficient Network Extensions (SENE).

The case study has been based on indicative network design and costings of different options for the network extension (and associated deep network augmentation and interconnector expansion, where relevant), prepared by ElectraNet. The case study also incorporates legal input from Minter Ellison.

Below we set out the key issues the SENE Rule Change is intended to address, before summarising the key aims of this case study.

1.1. What are the Issues that the SENE Proposal is Intended to Address?

The SENE proposal was developed in response to two issues identified by the AEMC in its earlier climate change review. The AEMC identified that in extending the existing transmission network to connect new clusters of generation:

§ The scale economies associated with transmission investment mean that, under the current arrangements, generators face a 'first mover' hurdle in financing such extensions. By building a larger capacity extension, the cost per MW of the extension falls; and

§ The capacity of such extensions may end up being less than is optimal from the perspective of the overall market, as the initial generators may not be willing or able to bear the financial costs and associated risk with building extensions which provide greater capacity than they themselves need. This may result in duplicate connection assets to the same area, the higher costs of which are ultimately reflected in electricity prices paid by customers.

These issues are important in the context of the expanded Renewable Energy Target (RET) scheme, given that the RET scheme is expected to drive investment in renewable generation, much of which may be in sites remote from the current transmission network.

1.2. Aims of the Case Study

The case study has the following three main aims:

1. To use an indicative case study of a transmission network extension to connect multiple wind generation developments in the Eyre Peninsula, in order to identify issues with applying the existing Rules, including the RIT-T, to such an extension. The case study has included an indicative RIT-T assessment.

2. To identify whether there are more proportionate changes to the Rules that would address the 'first mover' and 'right-sizing' issues identified by the AEMC. In particular two alternative models have been evaluated:
   - **Model 1:** Generators funding the stand-alone cost of the extension, with the RIT-T applied to further incrementing the capacity; and
   - **Model 2:** Generators funding a portion of the extension, where it would not otherwise pass the RIT-T.
3. To identify practical issues that would need to be addressed in the application of the proposed SENE model to the case study area.

In considering whether there are more proportionate changes to the Rules, we have considered models which incorporate a role for the RIT-T, as proposed by the MCE in its Rule Change Request. However we note that the AEMC may ultimately decide on a SENE model which does not incorporate a role for the RIT-T.

1.3. Structure of this Draft Report

The remainder of this report is structured as follows:

- Section 2 sets out the key parameters adopted for the case study, and summarises the status quo arrangements that would currently apply to extending the network to connect generation in the Eyre Peninsula;
- Section 3 discusses the application of the RIT-T to the network extension, including whether the RIT-T can be applied under the current Rules and the key issues that arise in applying the RIT-T to a network extension of this type;
- Section 4 discusses Model 1, under which generators would fund the stand-alone cost of the extension, with the RIT-T applied to further incrementing the capacity;
- Section 5 discusses Model 2, under which generators would fund a portion of the extension, where it would not otherwise pass the RIT-T;
- Section 6 summarises the key findings from the case study in relation to these two alternative models; and
- Section 7 highlights practical issues with applying the proposed SENE model to the case study extension.

2. Case Study Area: Eyre Peninsula

For the purposes of the case study, it is assumed that 2000MW of wind generation development is proposed on the southern Eyre Peninsula in four separate staged generation developments of 500MW. Two of these generation developments are in the East of the Eyre Peninsula (near Cleve) whilst a further two are located to the West of Eyre Peninsula (near Elliston).

For the purposes of the case study it is assumed that three wind developers have indicated an interest in connecting to the network, as shown below.

Table 2.1
Assumed Profile of Wind Generator Entry

Developer	Capacity	Timeframe
Company A	500 MW	Immediate
Company B	500 MW 500 MW	3 years 5 years
Company C	500 MW	Not committed

We note that the up-front development times for network investment (of up to 4 years for some of the network investments considered),[1] pushes back the time at which the first of these new generators is assumed to enter. Given the 2030 end-date for the RET scheme, substantial wind generation developments later in the period may be considered less likely. However, given that one of the aims of the case study is to consider how well the alternative models facilitate the entry of generation over time (ie, the 'right-sizing' issue), we have adopted the above staggered entry profile in all cases.

The indicative network investments considered in this case study to connect these generation developments has been developed by ElectraNet.[2] The elements of these network investments can be summarised as follows:

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1 For our indicative RIT-T assessment, in the case of the '2000MW – Eyre' option which also involves additional interconnector capacity, we have assumed that wind generation begins to enter once the extension to the network and deep augmentation within South Australia have been completed, rather than waiting until the interconnector investment has also been completed.

2 We note that the 'real world' analysis required in order to develop appropriate network extension configurations is complex, and includes the system performance studies required to evaluate affects of inertia, FCAS, voltage stability, system fault level, harmonics etc.

- An **extension** of the network South from Cultana to Cleve and then West to Elliston (double circuit 275kV): this extension is the portion of the network that would be considered a SENE under the AEMC's proposed Rule;

- **Connection assets**, relating to the construction of a new nodal substation at the remote end of the extension;

- **Deep network augmentation** within South Australia (275kV double circuit between Cultana and Davenport), which would be required in order to accommodate dispatch of 1000MW of additional wind generation within South Australia; and

- Expansion of the **interconnector capacity** between South Australia and Victoria, which would be required to accommodate dispatch of additional wind generation above 1000MW.

For the purpose of this case study, we have considered two options for network extension on the Eyre Peninsula:

- a network development to accommodate 1000MW of wind capacity, which could be undertaken with an extension of the network to Cleve plus deep network augmentation,[3] but without an expansion of interconnector capacity;

- a larger network development to accommodate 2000MW of wind development, which would require a longer network extension to Elliston and would need to be supported by an expansion of interconnector capacity, and deep network augmentation.

These options are illustrated in Figure 2.1 and Figure 2.2

We note that network extension to connect large quantities of generation may change the size of the credible contingencies that need to be met within a jurisdiction, in line with the provisions in clauses 4.2.2 and 4.2.3 of the National Electricity Rules (the Rules). This in turn will influence the design of the network extension. This impact is important in the Eyre Peninsula. It is assumed that the extension would need to be designed to meet these contingency requirements, whether it was undertaken as part of the development of the shared network or as a non-regulated extension, and has been incorporated in the design of the extension (ie, double circuit elements).

The extension of the network between Davenport and Cleve is in parallel to an existing 132kV transmission line, which may require upgrading in future to accommodate additional load in the Port Lincoln area.[4] The extension of the network to connect the wind generation could also be connected with the existing network at Yadnarie (although need not be), which would then replace part of this future upgrade to the existing network.

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[3] ElectraNet has estimated that around 1000MW of additional wind generation could be accommodated by load within South Australia, although there would need to be some supporting deep augmentation of the existing transmission network (particularly between Davenport and Para)

[4] ElectraNet has a contingent project included within its current Regulatory Determination (Eyre Peninsula Contingent Project), the trigger for which is a demand increase of more than 15MW in the Port Lincoln area.

Figure 2.1
1000MW - Eyre Option, Network Overview

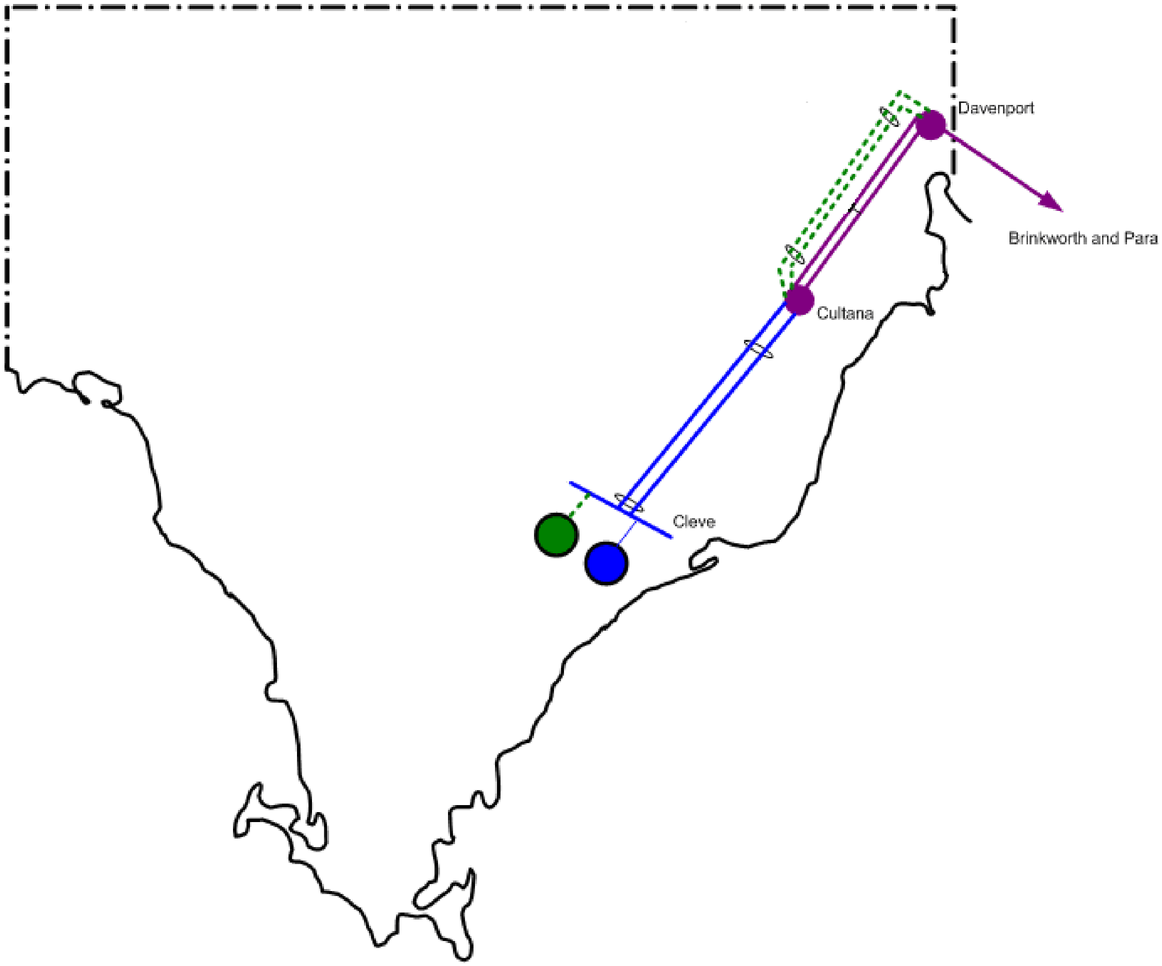
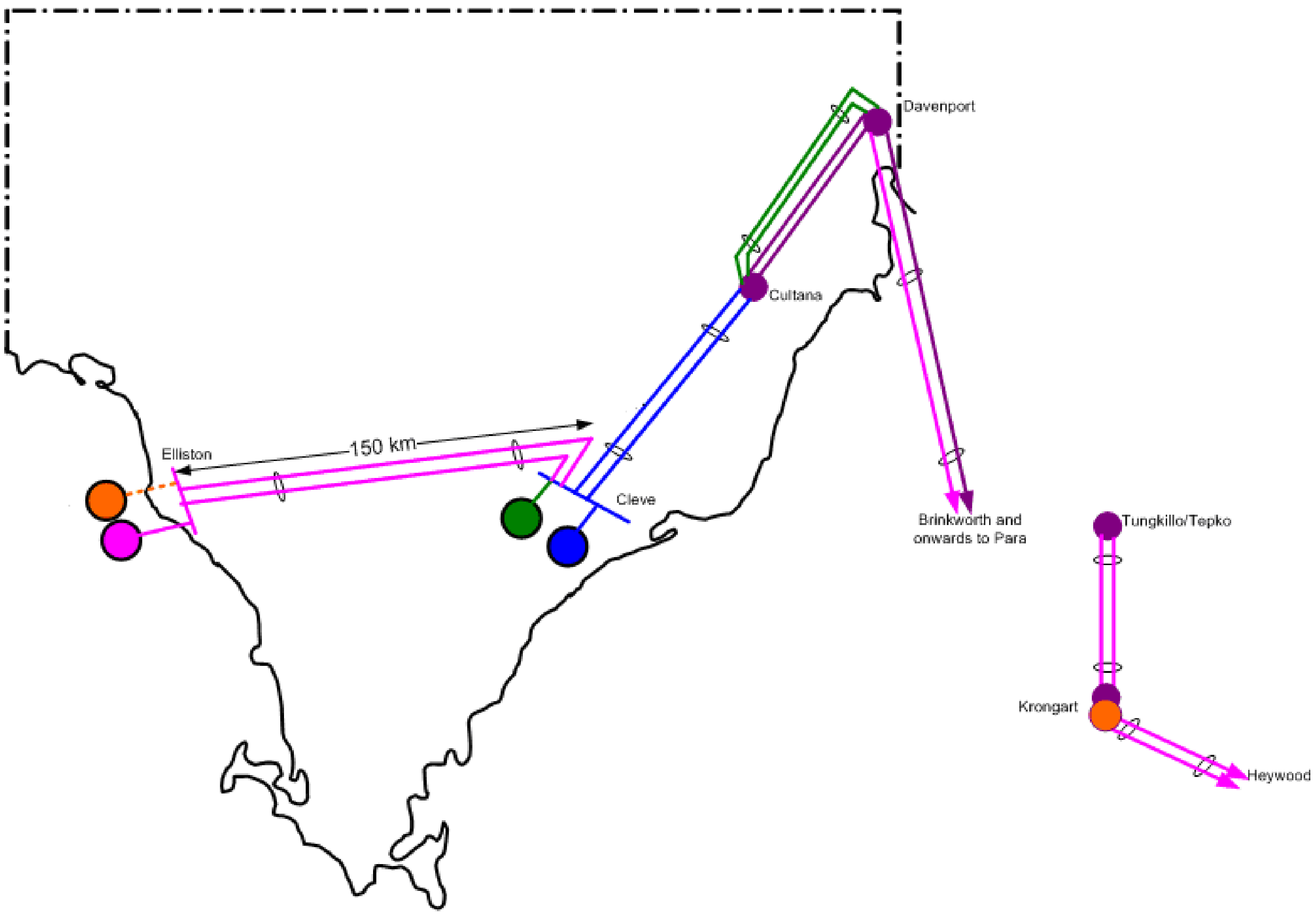


Figure 2.2
2000MW - Eyre Option, Network Overview



2.1. Status Quo Arrangements

Under the current Rules the extension of the network to connect the new generators in the Eyre Peninsula would be undertaken as a non-regulated service (as the extension is potentially contestable).[5] Generators would pay for the extension.

Generators would in theory be able to co-ordinate in order to share the costs of the extension. However in practice this is likely to be difficult given the different project timelines set out above. Alternatively the initial generator would be able to fund all of the extension (ie, for capacity in excess of its own needs), and then receive payments from later generators connecting to the extension. The initial generator's incentive to do this would be the economies of scale associated with building a larger-scale extension. However in practice the costs of the extension are likely to make it infeasible for the first generator to fund all of the costs up-front.

In this particular case, the economies of scale in relation to the extension are extensive, based on the following indicative costings:

§ A stand-alone connection to accommodate 500MW at Cleve: $200m.[6]

§ The incremental cost of connecting a further 500MW generator at Cleve: $40m.

§ The total cost of the extension to accommodate 2000MW of generation: $500m.

Under these indicative costings, a 500MW generator located at Cleve would therefore pay around $120m if it shared the shorter extension to Cleve with another 500MW generator (ie, 60% of the stand-alone cost it would otherwise face). It would still pay less if it incurred a quarter share of the larger extension all the way to Elliston (ie, $125m), which would be 62% of its stand-alone cost.

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5 Grid Australia, Categorisation of Transmission Services Guideline, Version 1.0, August 2010, section 3.2.

6 Network costings provided by ElectraNet.

3. Application of the RIT-T

We have assessed the potential application of the RIT-T to the case study, to identify issues with applying the RIT-T in the context of extending the network to connect renewable generation.

This section first considers whether the RIT-T can be applied to an extension to connect new generation, and concludes that it can. We then highlight the key market benefit categories that are likely to be important in such a RIT-T analysis, and note that they are heavily dependent on the assumptions made regarding future market development, and as a result may be more open to contention than in the case of other RIT-T applications. We then highlight specific issues with applying the RIT-T to a network extension to connect new generation, before presenting the results from our indicative RIT-T application to the case study and highlighting some general lessons that can be drawn from this analysis.

3.1. Can the RIT-T be Applied to the Extension?

Advice obtained by Grid Australia for the purposes of this case study confirms that in general terms there is nothing in Chapter 5 of the Rules which would prevent a TNSP from applying the RIT-T to any proposed transmission investment in relation to its transmission network, or to an extension beyond the existing network.

We note that the application of the RIT-T may potentially be to a wider scope of investment (including deep network augmentation), rather than only the extension. The RIT-T application would involve a market benefit assessment, against a base case of no extension to connect these potential wind developments. As discussed further below, the key areas of market benefit likely to drive the RIT-T assessment rely on the wind generation connected actually being dispatched in order to displace generation elsewhere and defer other generation investment. Where the wind generation would otherwise be constrained by the capacity on the existing shared network, deep network augmentation would need to be included as part of the credible option in the RIT-T assessment.

Where the extension (plus any associated deep network augmentation) passes the RIT-T, the network investment would be rolled into the Regulatory Asset Base and the cost would be recovered from customers as a prescribed service. The connecting generators would then only pay for the much smaller connection service, ie, the construction of a new nodal substation at the remote end of the extension.

3.2. Key Areas of Market Benefit Under the RIT-T

The RIT-T would involve a market benefit assessment, against a base case of no extension to connect these potential wind developments.

The key categories of market benefits expected from an extension of the network to connect additional wind generation would be:

- **Changes in fuel consumption arising from different patterns of generation dispatch**. The dispatch of additional wind generation in the Eyre Peninsula will displace the dispatch of generation in South Australia and/or elsewhere in the NEM. Whether or not this results in an overall net market benefit depends on the type of generation displaced:

- Where wind generation in South Australia displaces wind generation elsewhere, then there would be no overall market benefit (since there would be zero fuel costs in each case);

- Where wind generation in South Australia displaces conventional generation (either in South Australia or elsewhere) then there would be a benefit as a result of the lower fuel cost for wind compared to conventional generation in South Australia and elsewhere.

- However, this market benefit will depend on the overall change in conventional generation, and the relative fuel costs of different conventional generating plant. Reduced dispatch of conventional generation in South Australia may be offset by the additional dispatch of conventional generation elsewhere in the NEM, compared to the base case;[7]

- This size of the market benefit associated with changes in fuel consumption will be larger where it is assumed that a carbon price signal is in place (eg, via the CPRS, as this increases the effective fuel costs for conventional generation but not for wind generation. Whether or not such a price signal will be introduced, and the timing of its introduction, is currently highly uncertain.

§ Wind generation in the Eyre Peninsula would also be expected to **defer or to displace other investment in generation**, resulting in an additional market benefit. Again, the size of the benefit will depend on the generation investment which is assumed to be deferred/displaced, compared to the cost of the wind development in the Eyre Peninsula:

- The cost of the additional wind generation in the Eyre Peninsula would represent a cost in the RIT-T analysis, as this investment would not be assumed to occur in the base case. The relatively high capital cost of wind generation means that this cost is substantial;

- Wind generation investment in the Eyre Peninsula may displace wind generation investment elsewhere, if the development of wind generation it is assumed to be driven by meeting the RET target.[8] Overall there may be a net market benefit, since the quality of the wind resource in the Eyre Peninsula is generally considered to be higher than in other locations,[9] which means that producing the same MWh output from wind generation would require a larger scale (and therefore higher capital cost)

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7 This will be the case where the background market development scenario includes wind generation elsewhere in the NEM. Displacement of this wind generation with additional wind generation in South Australia will raise dispatch costs elsewhere in the NEM from what they would be in the base scenario, whilst lowering dispatch costs in South Australia.

8 ie, assuming that the REC price will rise to a level which provides sufficient commercial drivers for the RET target to be met. We have not assessed as part of this case study whether or not this condition may hold.

9 Source: wind generation atlas - http://www.climatechange.gov.au/what-you-need-to-know/renewable-energy/atlas.aspx).

investment in another location. Again, the relatively high capital cost of wind generation means that this displacement may represent a substantial market benefit;

- Wind generation investment in the Eyre Peninsula may defer or displace conventional generation development in South Australia (or elsewhere). In this case whether or not there is an overall net market benefit will depend on whether the value of the deferral (which will depend on the type of generation deferred and the length of deferral assumed) outweighs the capital costs of the wind development.

§ Development of wind generation in the Eyre Peninsula may also require **additional investment in conventional OCGT generation**, to provide the necessary back-up and address intermittency issues, and reliably meet the underlying demand. This would represent an additional market cost in the RIT-T analysis (to the extent that these generators would not be needed in the base case):

- where the interconnector capacity is expanded, then South Australia could draw on generation resources elsewhere in the NEM to provide the necessary back-up, and so additional OCGT investment would not be needed;

- where the interconnector capacity is not expanded, additional OCGT generation would be needed within South Australia.

The above categories of market benefits rely on the wind generation connected actually being dispatched, in order to displace generation elsewhere and defer investment in other generating capacity. This implies that some deep network augmentation would need to be included as part of the options in the RIT-T assessment, where the wind generation would otherwise be constrained by the capacity of the shared network.[10] This in turn increases the costs of the transmission investment included in the RIT-T analysis. For the Eyre Peninsula case study we have considered:

§ deep network augmentation within South Australia to enable 1000MW of wind to be dispatched, with no interconnector augmentation;

§ the expansion of interconnector capacity from South Australia (in addition to deep network augmentation), to enable 2000MW of wind generation to be dispatched to meet demand in South Australia and for export to rest of the NEM.

In the case of the Eyre Peninsula, an extension of the transmission network to connect wind generation may also displace future investment in the shared network. This represents an additional market benefit in the RIT-T assessment.[11] Specifically future network augmentation to Port Lincoln will be required once demand in that area increases beyond the capability of the existing network.[12] However in general, extensions of the network to new

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[10] The extent of deep augmentation would be unlikely to remove all constraints on the dispatch of the renewable generators, but would reduce them sufficiently to enable the generators to be dispatched to a level which results in sufficient market benefits being realised.

[11] ie, differences in the timing of transmission investment.

[12] ElectraNet has a contingent project included within its current Regulatory Determination (Eyre Peninsula Contingent Project), in relation to this investment.

areas are not likely to displace future network investment. As a result this would not generally be an important RIT-T benefit category.

We note that one of the options considered under this case study also includes the expansion of interconnector capacity from South Australia to the rest of the NEM. An expansion of interconnector capacity will have a significant impact on the pattern of power flows and dispatch, as well as the relative competitive position of generators in the market. This means that the impact of connecting the additional wind generation in the Eyre Peninsula on the underlying pattern of market dispatch and NEM investment would become more complex, as it would also depend on the impact of the additional interconnection. The RIT-T assessment in this case would also need to take into account other categories of market benefit, including changes in losses and competition benefits. These categories of market benefit are unlikely to be as significant in the case of a RIT-T assessment limited to an extension of the network to connect additional generation.

3.2.1. Summary

The RIT-T would involve a market benefit assessment, against a base case of no extension to connect these potential wind generation developments. It would also be important to include deep network augmentation as part of the credible options assessed under the RIT-T, if the output of the renewable generators would otherwise be constrained by capacity on the shared network. This is because the key categories of market benefit associated with the connection of additional generation depend on that generation actually being dispatched.

The key categories of market benefits will be those associated with the displacement of generation elsewhere, both in terms of dispatch and future generation investment. Market development modelling will therefore be important for any RIT-T assessment of a network extension to connect addition generation, including the assumed future development of wind generation in the NEM in response to the RET (noting that the RET is an Australia-wide target, and is not restricted to the NEM):

§ where additional wind generation is assumed to displace investment in conventional generation, rather than other wind investment, there will be a significant market cost associated with the high capital cost of the wind development, compared to conventional generation;

§ assumptions regarding the relative efficiency of wind generation in different locations is likely to be an important driver of market benefits, where it is assumed that the additional wind generation displaces investment in wind generation elsewhere;

§ market benefits from changes in the fuel consumption will be heavily dependent on the assumed changes in generator dispatch patterns between the base case scenario and with the alternative transmission investment options. This in turn will depend on the base case scenario considered.

Our indicative RIT-T analysis (discussed further in section 3.4) shows that the assumed market development scenario can have a significant impact on the outcome of the RIT-T.

An assumption that a carbon price signal is in place (eg, via the introduction of the CPRS) increases the value of the benefit associated with changes in fuel consumption, where the generation displaced by dispatch of the additional wind generation is assumed to be conventional generation. Our indicative RIT-T assessment shows that whether or not such a signal is assumed to be in place does have a material impact on the market benefit calculated, and results in options moving from having a positive net market benefit to having a negative net market benefit. An assumption that a carbon price is in place will also affect the underlying market development scenario, and therefore the market benefit associated with the impact of the extension on the future development of the generation market.

Given the importance of the assumptions around future market development (including the introduction of a carbon price), applying the RIT-T assessment to an extension to connect new generation clusters may be subject to a larger degree of uncertainty (and therefore potential dispute) than for other RIT-T assessments.

3.3. Issues in applying the RIT-T

This section discusses some specific issues with applying the RIT-T to a network extension to connect new clusters of generation. These issues are illustrated by reference to the case study but have more general applicability.

3.3.1. What is the appropriate base case?

As highlighted in the previous section, the key categories of market benefit in the RIT-T assessment will be driven by the impact of the additional renewable generation on generation investment and dispatch outcomes in the NEM. The assumptions made in relation to the base case market development scenario will therefore be of key importance to the analysis.

For the Eyre Peninsula extension it will be important to determine whether the base case generation development scenario (ie, in the absence of the extension proceeding and facilitating the development of new wind farms in the Eyre Peninsula) would be conventional generation in South Australia, renewable generation elsewhere in the NEM or a combination.

For the purposes of our indicative RIT-T analysis, we have adopted two alternative market development scenarios – as indicative of the potential range of scenarios that may be considered. These scenarios are set out in detail in Appendix 1. Our indicative RIT-T results are heavily dependent on which of these scenarios is adopted for the assessment.

Given that the choice of the base case market development scenarios have the potential to change the outcome of the RIT-T assessment, they are likely to be contentious and may be subject to dispute by interested parties.

In order to address this issue, it may be appropriate for AEMO as part of its National Transmission Network Development Plan (NTNDP) to set out generation development forecasts which are sufficiently detailed to provide the basis for the base case assumptions. Under the current Rules, AEMO is required to:

§ identify a range of credible scenarios for the geographic pattern of electricity supply over the NTNDP planning horizon;[13] and

§ to establish a NTNDP database which, amongst other things, is to include the 'prevailing location of generation capacity'.[14]

Extending AEMO's responsibilities to develop generation development forecasts which are sufficiently detailed to provide the basis for the base case assumptions would provide an 'independent' basis for the assumed pattern of generation investment assumed in the base case, which the TNSP could take as a starting point (and adapt where it has additional information). This would be consistent with the role envisaged for AEMO under the SENE Rule Change Proposal of verifying the TNSP's forecasts of future generation, in that requires AEMO to have a view as to future patterns of generation development.

3.3.2. Forecasts of future wind generation capacity

The capacity of the proposed network extension would be dependent on the TNSP's forecasts of future wind generation developments in that area. The extent of future wind development would also be a key driver of the market benefits in the RIT-T analysis (as they relate to the displacement of generation investment and fuel cost savings as a result of the additional wind generation).

A key issue for the RIT-T analysis is therefore what the forecasts of future wind generation in the area would be based on, and how defendable they would be.

The TNSP's best information on future generation development is likely to come from connection enquiries, and pre-feasibility activities being undertaken for prospective connecting parties. However there are confidentiality issues raised with using this information publicly, even given the recent Confidentiality Provisions for Network Connection Rule change[15]. This potentially leaves the TNSP's estimates open to challenge. The TNSP could also consider the strength of the commercial drivers for such investment, including the quality of the wind resource (backed up by independent assessments such as wind atlas reports) and the cost of land in that area and whether there are likely to be planning restrictions. However, this analysis could also be controversial.

The TNSP could base its forecasts on information in AEMO's NTNDP. AEMO has yet to publish its first NTNDP. However, AEMO's NTNDP Consultation Paper includes provisions for AEMO to model new entry wind generation as part of the NTNDP.[16] This modelling is proposed to be conducted for individual geographic groupings of wind generation (or 'wind bubbles'), one of which is the Eyre Peninsula.

The TNSP could run a Request for Proposal (RFP) process, in order to gauge potential generator interest. This would be similar to the 'SENE invitation period' in the draft SENE

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13 National Electricity Rules, clause 5.6A.2 (c) (3), Version 36.

14 National Electricity Rules, clause 5.6A.4 (b) (4), Version 36.

15 Which commenced operation on 12 November 2009, and involved amendments to clause 5.2.8.

16 AEMO, 2010, *National Transmission Development Plan: Consultation Paper – Appendix B*, Section B.4.15.

Rules, where potential generators are invited to submit connection enquiries in relation to a particular SENE zone. However, unless there was a payment involved, this would be likely to result in an overestimation of potential generating capacity, as there would be no downside for potential generators to responding to such requests. The TNSP could attempt to 'sense-check' the responses received, for example, by giving greater weight to proven players. However this again has the potential to be controversial.

Responses from an RFP process would carry more weight where there was a payment involved. One approach would be for TNSPs to require generators to contribute to the costs of applying the RIT-T, as an indication of their firm interest.[17] This would be similar to the current (non-regulated) arrangements for generators to contribute to funding connection studies in relation to generator connection enquiries. In the context of the SENE model, the AEMC earlier suggested that TNSPs could charge enquiring generators a fee to recover any necessary costs and limit the scope for speculative or vexatious enquiries,[18] although we note that this is not reflected in the draft SENE Rules.

Although the above discussion highlights the potential difficulties with developing future generation forecasts, we note that the same issue in relation to the basis for future generation forecasts arises under the proposed SENE model, rather than being an issue specific to the RIT-T application.[19]

3.3.3. Alternative Credible Options

We have identified three issues in relation to the identification of alternative credible options under the RIT-T analysis:

§ there is no clear limit on the scope of the alternative options that could be considered under the analysis;

§ an alternative extension which connects another source of generation may pass the RIT-T; and

§ the design (and therefore the cost) of the extension may differ if undertaken as part of the shared network, rather than as a non-regulated extension.

3.3.3.1. Scope of potential options

It may be difficult and/or controversial to limit the scope of the credible options considered as alternatives to a particular network extension under the RIT-T analysis. Stakeholders could press for consideration of alternative credible options involving network extension to connect

17 There is a precedent in VENCorp's 2007 Connection Augmentation Guideline, which states (p. 22) that the connection applicant will fund VENCorp's preliminary assessment of whether a requested augmentation (associated with a connection) is likely to pass the regulatory test.

18 AEMC 2nd Interim Report, Appendix F, p.160.

19 The only difference is that any overestimation of future generating capacity under a RIT-T application would result in the stranded costs of the investment being borne by customers (assuming the extension passes the RIT-T), whereas under the SENE proposal the investment would be at least partially funded by the initial generator. However, given that there is no minimum share of the capacity that the initial generator needs to commit to under the SENE model, in practice this may not be a substantive difference.

renewable generation in other areas across the NEM. Responding to the RIT-T Project Specification Consultation Report provides a platform for stakeholders to raise additional options, although the TNSP has discretion in determining whether these are credible options to be evaluated under the RIT-T.

This is an issue common to all market benefit RIT-T assessments, as the identified need in this case is expressed only as ‘an increase in consumer and producer surplus in the NEM.’[20] As a result there is no clear delineation on what should be considered ‘alternative’ credible options.

The precedent is for credible options to be options which result in market benefits as a result of addressing the same network constraint (eg, expanded transfer capability between Qld and NSW in the case of the QNI regulatory test assessment). However the context of the RET may make this more controversial: the RET is an Australia-wide target rather than limited to a specific region, and there are likely to be winners and losers as a result of a particular network extension going ahead, and so strong vested interests.

To prevent the proliferation of spurious options, one possible approach could be to require parties wishing to promote alternative credible options (either as the proponent of that option, or generators that would benefit from that option) to make a contribution to the costs of the RIT-T assessment.

3.3.3.2. An alternative option passes the RIT-T

Notwithstanding the above discussion about the potential difficulty of limiting the scope of alternative credible options, it is possible that there are alternative credible options that would be included within the scope of a RIT-T analysis which relate to different network extensions. That is, not only could alternative credible options relate to different capacities and design of an extension to connect the generation in the same area, but there may be an alternative credible option that would extend the network to a different area, and result in a different group of generators connecting.

In the case of the Eyre Peninsula, our indicative RIT-T application indicates that a network extension to connect wind generation closer to Davenport potentially has a greater net market benefit than the alternative extensions to the Eyre Peninsula (since the network costs of this option are lower, whilst the market benefits are comparable). If confirmed,[21] this would imply that the Eyre Peninsula extensions would not pass the RIT-T, because of the presence of this alternative option, even if there were market development scenarios which resulted in a positive market benefit for the Eyre Peninsula options.

This outcome is not a problem, *per se*, as it results in the investment which maximises the net market benefit being identified by the RIT-T. However it does highlight a potential limitation in being able to use the RIT-T to justify a network extension to a specific location.

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20 AER, Draft RIT-T Guidelines, section 3.1.

21 Confirmation of this result would include being able to demonstrate that there are expected to be wind generators wanting to connect in this area.

3.3.3.3. Whether the investment differs if undertaken as part of the shared network rather than as a non-regulated investment

The third issue we have identified is that the configuration of the network options may differ if they are being considered as an extension of the network under the RIT-T, rather than as a non-regulated extension (or under the SENE framework). For example, an extension may be developed as a double circuit line if it is part of the regulated network compared to as a single circuit line (lower cost) if it was developed as a non-regulated extension.

In the specific case of the Eyre Peninsula, the design of the extension is driven by the need to meet the (higher) contingency standards once the additional generation is connected. This would be common whether the extension is developed as part of the shared network or separately as a non-regulated extension. However we understand that this could be an issue for other network extensions.

3.4. Indicative RIT-T Assessment

We have carried out an indicative RIT-T assessment as part of this case study, based on four illustrative network options[22] and two possible market development scenarios (one based on future conventional generation and an alternative including future wind generation development in Victoria). We have also undertaken sensitivity analysis to identify the extent to which the results are dependent on key assumptions.

The results of our RIT-T assessment are illustrative only. Given the central importance of the assumed pattern of future generation investment in the NEM, and the impact of the alternative options on that investment pattern, a comprehensive RIT-T analysis would need to incorporate detailed market modelling. Moreover, one of the options considered (Option '2000MW – Eyre') also involves expansion of the interconnector capacity between South Australia and Victoria, and our RIT-T assessment has not taken into account potential market benefits arising from competition benefits or changes in network losses in this case, which may be significant in reality.

Notwithstanding the limitations of the current exercise, the indicative RIT-T analysis does highlight some useful lessons, namely:

- The key importance of the assumed base case market development scenario to the results of the RIT-T assessment. Our results show that none of the options have a positive net market benefit under our assumed conventional generation base case scenario, but that three of the four options have a positive net market benefit under a base case market development scenario including additional wind generation development in Victoria.
  - The key driver behind this result is that where the base case generation scenario does not assume that there is alternative wind generation in other locations, the substantial capital cost of the wind farm development in South Australia outweighs the benefits associated with the deferral of conventional generation and lower cost dispatch.

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[22] The four network options considered are summarised in Appendix 1.

- Under the market development scenarios we have considered, using our central set of assumptions, the 2000MW Eyre Peninsula option would not have a positive net market benefit, but the 1000MW Eyre Peninsula option does have a positive net market benefit, depending on the particular market development scenario adopted.

- The 1000MW – Northern option has a higher net market benefit than the 1000MW - Eyre Peninsula option, as a result of having lower network costs, but comparable market benefits. As a result, even under the market development scenario and set of assumptions where the 1000MW - Eyre Peninsula option has a positive net market benefit, this alternative option would be ranked higher under the RIT-T. However this result is very sensitive to the assumption made as to the relative efficiency of a wind farm in the Northern region compared with the Eyre Peninsula.

- The magnitude of the market benefit is very sensitive to the assumed capital costs for wind farms. We have used an assumption for these costs below that which has been adopted by AEMO as part of the NTNDP modelling assumptions but above the costs of some recent large-scale Australian wind farm developments. Adopting the lower capital cost assumptions results in all of the 1000MW credible options having a positive net market benefit under the conventional generation scenario.

- Our indicative RIT-T assessment shows that whether or not a carbon price signal is assumed to be in place does have a material impact on the market benefit calculated, and whether or not an option has a positive net market benefit overall, as it impacts the value of avoided fuel costs where the wind generation displaces the dispatch of conventional generation.

- Changing the assumptions about the extent of the deferral of conventional generation investment under the conventional generation scenario does not affect the results significantly for the 1000MW options. For the 2000MW option (which includes the interconnector investment), it would be necessary for both of the assumed conventional generation investments to be completely abandoned in order for this option to have a positive net market benefit.

- We have carried out an indicative assessment of whether the cost of the deep augmentation alone in the '1000MW – Eyre' credible option would pass the RIT-T. Our assessment indicates that, assuming that the output of the wind generators would otherwise be completely constrained, then the associated deep network augmentation would pass the RIT-T. We have tested the robustness of this result to changes in key assumptions (including an assumption that 500MW of wind generation could be dispatched in the absence of the deep network augmentation, and that there is no carbon price) and found that the deep network augmentation continues to pass the RIT-T under these alternative assumptions.

4. Model 1: RIT-T Applied to Additional Capacity Only

The MCE in its Rule change request has proposed that TNSPs be required to apply the RIT-T as part of the SENE model.

We have considered a possible model (Model 1) under which generators would fund the network extension, and the RIT-T would then be applied to additional, incremental capacity. Specifically, generators would pay their stand-alone cost for the extension and connection. The generators would not pay any deep augmentation costs (unless they chose to).

The TNSP could then apply the RIT-T to see whether additional capacity for the extension over and above that funded by the generator would pass the RIT-T (ie, would have a positive net market benefit). This RIT-T application would also be likely to include complementary deep network augmentation, if the dispatch of generators connected to the extension is likely to be significantly constrained by the existing capacity on the shared network.[23] If so, customers would fund the additional capacity. Under this approach, customers pay less than if the extension was all funded under the RIT-T.

4.1. Is Model 1 Facilitated under the Current Rules?

Model 1 would be largely accommodated by the existing Rules. The RIT-T assessment would include the extension to connect the initial generator(s) as part of the base case. As a result, the stand-alone cost of this extension would be treated as a sunk cost, and the impact of connecting this generator on the pattern of dispatch and investment in the NEM would be included in the base case market development scenario. The RIT-T assessment would then estimate the net market benefit associated with increasing the capacity or varying the configuration of this initial investment, and would include the additional cost of this incremental investment as well as the costs and benefits arising from the additional impact on the wider market.

Under this approach, any necessary deep augmentation would need to be considered in the incremental RIT-T assessment, as market benefits are only realised where the wind generation is actually dispatched.

Under Model 1, the generator would not receive any capacity rights in relation to the extension, consistent with existing arrangements.

If the initial generator was prepared to agree to fund the stand-alone cost of the extension, it is likely that the initial generator would also require the inclusion of a provision in its connection agreement specifying the manner in which its charges and/or any pre-payment or capital contribution would be adjusted to reflect the extent to which the extension was used to provide services to a subsequent generator (ie, the charges payable by the initial generator would be reduced to reflect the charges agreed to be paid by the subsequent generator in relation to the extension).

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[23] See discussion in section 3.1

This approach reflects the Negotiated Transmission Services Principle set out in clause 6A.9.1(6). Whilst this principle is intended to govern the negotiation of the terms and conditions of access for negotiated transmission services there is nothing in the Rules which would prevent the TNSP and the initial generator from agreeing to apply the same principle in relation to any other form of funding provided by the initial generator in relation to the construction of the extension. In addition, it is difficult to envisage a situation where a TNSP could argue that it was fair and reasonable not to include this type of provision. Grid Australia's Categorisation of Transmission Services Guideline contains a statement that extends this principle to non-regulated services.[24]

We note that there are precedents from DNSP extensions to connect remote customers, which include rebate provisions where the extensions are subsequently also used by other customers.[25]

4.2. Does Model 1 Address the Issues Identified by the AEMC?

Model 1 does not directly address the first mover issue, as the first generator would still face the full stand alone cost of the extension (excluding the economies of scale). From the illustrative costs provided for the case study, the economies of scale are substantial (see section 2.1).

The initial generator does however stand to benefit from a potential reduction in its future costs, arising from the economies of scale from building the larger extension. Under the status quo approach (discussed in section 2.1), an initial generator could decide to fund a larger capacity extension than required for its own needs, in the hope that later generators will also connect and fund a portion of the extension. The initial generator would benefit from the economies of scale if future generation did emerge, but would bear the risk that further generation does not eventuate, as well as facing increased up-front financing costs, which may represent a practical hurdle to this approach.

Under Model 1 it is customers who fund the increased cost of the extension, and bear the potential stranding risk, whilst the initial generator would still benefit from the realisation of economies of scale if future generation did emerge.

The initial generator therefore faces a trade-off between the delay associated with gaining regulatory approval for the enhanced investment under the RIT-T (compared with undertaking the extension as a non-regulated investment) and this potential future reduction in costs. Generators who didn't want to accept this trade-off could still elect to pay for the investment as a non-regulated service.

Model 1 partially addresses 'right-sizing' connections and avoiding the cost of multiple connections. Additional capacity to accommodate future generation would be developed up to the point where the additional capacity passes the RIT-T. However this may not reflect the full extent of possible future generation development in that area.

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[24] Grid Australia, Categorisation of Transmission Services Guideline, Version 1.0, August 2010, Section 3.6.

[25] Country Energy, Reimbursement Scheme for Rural and Large Load Customers, 19 July 2002.

4.3. Summary of Model 1

Who funds the extension?	Generators, up to the stand-alone cost for the first generator(s) Customers for the incremental portion that passes the RIT-T
Who bears the risk that future generation doesn't materialise?	Customers in relation to the incremental portion only Initial generator(s) bears all of the stand-alone cost if there are no subsequent generators.
Addresses first mover issue?	No – the first generators pay the stand-alone cost
Addresses right-sizing issue?	Partially – future generation would be accommodated up to the point where the additional capacity passes the RIT-T. However this may not reflect the full extent of possible future generation development in that area.
Provides generator with certainty over access to the extension?	No

5. Model 2: Generator Funding of Part of the Extension, where the Investment Doesn't Pass the RIT-T

In its response to the AEMC's Final Report on the Review of Energy Market Frameworks in Light of Climate Change Policy, the MCE proposed the imposition of an obligation on NSPs to consider any benefits that may accrue to consumers as a result of the SENE and to apply the RIT-T, with the result that where benefits are found to exist, part (or all) of the SENE may be permanently funded by consumers.[26] The MCE's proposal raises the prospect of 'part' of a SENE passing the RIT-T and being permanently funded by customers via TUOS, and 'part' being recovered via the alternative SENE arrangements.

We have therefore considered a proposed model (Model 2) under which potentially connecting generators would be able make a contribution to offset some of the network capital costs, where an extension does not pass the RIT-T. We have considered the scope of changes that would need to be made the existing Rules to facilitate this model. We have also considered the extent to which this model may address the concerns identified by the AEMC in relation to the first-move disadvantage and 'right-sizing' extensions to new clusters of generation.

5.1. When Would this Model Apply?

An extension to connect all forecast new generation in an area may not pass the RIT-T for the following reasons:

1. The cost of the extension (plus supporting deep network augmentation) may not outweigh the market benefits. In this case the 'do nothing' option would pass the RIT-T;
2. A smaller-sized extension (plus supporting deep network augmentation) which connects some but not all of the forecast generation may pass the RIT-T; or
3. An alternative credible option which connects generation in another area may pass the RIT-T, if it provides a greater net market benefit.

In relation to the first reason above, there are a couple of factors that may raise the costs of the required investment, where the extension is considered as part of a RIT-T analysis.

The first is that deep augmentation costs associated with reducing constraints in the shared network on the dispatch of the generators may need to be included in the RIT-T analysis, in order for the overall investment to generate benefits.[27] This may increase the overall cost of the credible option to the point where it does not result in an overall net market benefit. If the generator(s) were to fund the extension, then the deep augmentation investment on its own may pass the RIT-T, as the costs of this option would fall,[28] whilst the market benefits may

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26 Ministerial Council on Energy, Review of Energy Market Frameworks in Light of Climate Change Policies, Response to AEMC Final Report, December 2009, p. 4.

27 See discussion in section 3.2.

28 Both the costs of the network investment and the costs of the new wind generation itself, as these would both now be sunk costs which would not enter the RIT-T analysis.

still be substantial if there is significant congestion in the absence of deep network augmentation. However, if the generator(s) fund the extension (as a non-regulated service) in isolation of a wider RIT-T assessment including the deep network augmentation, then this may raise unacceptable project funding risk.[29]

The second factor is that (as discussed earlier) the network configuration itself may be higher cost as a result of the extension being undertaken as part of the shared network, rather than as a non-regulated extension funded by the connecting generators. However we note that in the case of an extension in the Eyre Peninsula this does not apply, since the connection of 500MW plus of generation would be likely to impact the credible contingencies which the network must withstand, and therefore will require the same double-circuit design, whether it is developed as part of the shared network or as a non-regulated extension funded by the generators.

5.2. Is Model 2 Facilitated Under the Current Rules?

We have considered whether the current Rules facilitate payment by generators in relation to an investment which only 'partially' passes the RIT-T. We note that the MCE's Rule change proposal raises the prospect of 'part' of an investment passing the RIT-T and being permanently funded by customers via TUOS, and 'part' being recovered via an alternative arrangement.

There is scope under the existing Rules for generators to fund part of an investment. In general, nothing prohibits a generator from making a general payment to a TNSP under the Rules. Such a payment may be treated as a negotiated service or as a capital contribution. The generator would not receive any capacity rights as a result of providing this additional funding, consistent with the current arrangements.

Under the current Rules, payments from a generator to the TNSP under the RIT-T would not affect the outcome of the RIT-T. Such a payment would represent a wealth transfer (ie, an increase in consumer surplus but reduction in producer surplus). As a result, payment of an amount by a generator in order to bridge the gap between the assessed market benefit and costs would not alter the outcome of the RIT-T and so would not result in the investment being considered to have passed the RIT-T.

As noted in section 5.1, there are different circumstances in which an investment could 'partially' pass the RIT-T.

- A lower capacity expansion could pass the RIT-T (and therefore those costs could be properly allocated to prescribed services). The TNSP could then elect to undertake an investment of a higher capacity, the incremental cost of which would not be recovered from prescribed charges.

[29] Our indicative RIT-T analysis for Eyre Peninsula illustrates that deep augmentation associated with connecting 1000MW of wind generation close to Cleve would generate a positive net market benefit, assuming that the generators funded the extension of the network between Cultana and Cleve.

- The investment (even at its lowest capacity) may have a negative net market benefit, ie, fail to pass the RIT-T. For example, there may be a $100m investment that has a net market benefit of -$20m (NPV). Generators may opt to fund the $20m shortfall. However, this would still not result in the investment being considered to pass the RIT-T, as the $20m would be treated as a wealth transfer in the RIT-T, rather than a reduction in the TNSP's investment cost. Given that the investment has not passed the RIT-T, and that the $80m spent by the TNSP cannot be considered as a discrete investment (ie, it is part of the overall $100m investment, and couldn't be undertaken on a stand-alone basis) – without an amendment to the current Rules it appears it would be difficult to allocate the $80m cost to prescribed services.

It therefore appears that it may be necessary to amend the Rules to facilitate the MCE's concept of an investment being 'partially funded' via the RIT-T.

If the initial generator agreed to pay the costs of the proposed transmission investment in excess of the costs which satisfied the RIT-T, the initial generator would require the TNSP to agree in its connection agreement to adjust the initial generator's charges to the extent that the extension is being used to provide services to another generator wishing to connect a new generating system to the extension.

The TNSP would be required to reflect this principle in its connection agreement with the initial generator if the initial generator was being charged for the provision of negotiated transmission services. Whilst this Negotiated Transmission Services Principle does not apply to non-regulated transmission service, it is likely that the TNSP would agree to apply the same concept in relation to future adjustments to the price paid by the initial generator for the provision of any non-regulated transmission services using the extension. In that regard, we note that clause 5.3.6(c) of the Rules requires that an offer to connect must be fair and reasonable. The concept of 'reasonable commercial terms' is also referred to in the AER Network Service Provider exemption conditions.

5.3. Determining the Required Generator Contribution

Under Model 2, it would also be necessary to consider how the amount the generators would be required to fund would be worked out.

One option would be to link the amount the generators would have to pay to the NPV outcome of the RIT-T analysis.

Table 5.1 presents a stylised example, assuming that there are two credible options which provide different capacities (ie, Option 1 provides 100MW; Option 2 provides 200MW).

Table 5.1
Determining the Required Generator Contribution

	Option 1: 100 MW	Option 2: 200 MW
Cost	$100m	$150m
Benefit	$120m	$140m
Net market benefit	+$20m	-$10m

Option 1 passes the RIT-T, as it results in the greatest net market benefit. Although Option 2 provides increased market benefits compared to Option 1, it also has a higher cost[30] resulting in a negative net market benefit over all.

If generators wanted to ensure that the larger capacity extension was built, then in order to for Option 2 to pass the RIT-T, its costs would need to be $30m less (resulting in a net market benefit of $20m, the same as for Option 1). Under this approach, the payment required by the generators would need to be $30m, and is calculated on the basis of the value of the net market benefit estimated for the highest ranked option.

However we note that linking the amount which the generators are required to pay to the NPV analysis under the RIT-T is potentially problematic. Currently it is the ranking of projects under the RIT-T which is important, rather than the actual NPV outcome. This has implications for the way in which the RIT-T analysis is untaken, and means that where the rankings are robust to a range of different input assumptions it is not necessary to identify the most 'correct' input assumption. This issue is exacerbated by the fact that the key drivers of the market benefit estimates for this type of network extension are likely to be difficult to determine with precision (ie, future generation market development scenarios, relative efficiency of wind generation in different locations).

A second alternative would be for the generators to fund the difference in capital costs between the smaller capacity option and the larger capacity option, which in the above example would be $50m. This approach would have the advantage of not depending on the values of the NPV analysis in order to determine the required payment.

However, the second approach requires there to be a smaller scale option which does satisfy the RIT-T. As discussed earlier, an option may not pass the RIT-T because the costs do not outweigh the market benefits. It may be that a 'smaller sized' option might also not pass the RIT-T (for example, if the market benefit for option 1 in the above table were $90m, rather than $120m). Alternatively, there may not be a feasible 'smaller sized' investment to use as a benchmark for determining costs. In both of these cases the amount required to be paid by the generators would then be determined by the difference between Option 2 and the 'do nothing' case, ie, $10m. This amount is again dependent on the actual NPV value calculated for Option 2.

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30 This may reflect a greater extent of deep augmentation required, for example.

5.4. Does Model 2 Address the Issues Identified by the AEMC?

Model 2 does address the first mover issue, as the amount that the initial generator would have to pay for the extension would fall compared to the stand-alone cost. Under this model, customers would permanently fund that portion of the investment which passes the RIT-T.

Model 2 does not by itself necessarily address the right sizing of capacity. Generators would need to be prepared to pay the additional funding payment at the start of construction. If there is a smaller investment which passes the RIT-T and provides sufficient capacity for the first mover generator(s), then they would have no incentive to pay for additional capacity.

In the case study example, company A has no incentive to pay if a 1000MW option passes the RIT-T, provided that its capacity is close to Cultana. There would be no cost reductions for Company A under this model arising from economies of scale, since the extension is funded by customers under the RIT-T.

Company B may (in theory) have an incentive to fund the additional capacity, given that it ultimately is interested in 1000MW of capacity – especially if that capacity is located is the Elliston area. However this incentive would be undermined by it not being guaranteed access to the capacity that it funded, given the risk that company C may also enter the market. Company C is not committed, and so is unlikely to fund additional capacity beyond 1500MW. In reality, given that the difference between the 1000MW extension and the 2000MW extension also triggers the interconnector upgrade, the amount which generators would have to fund is likely to be prohibitive in this example.

In order to facilitate the development of capacity sized to meet future generation needs, Model 2 would therefore need to be combined with a similar 'interim customer funding' approach as proposed under the SENE model. There would also need to be provisions for the generators providing the initial funding to be reimbursed by later generators (as discussed in section 5.2).

5.5. Summary of Model 2: Generator Contribution under RIT-T

Who funds the extension?	Customers for the portion that passes the RIT-T Generators for the remaining portion
Who bears the risk that future generation doesn't materialise?	Customers in relation to generator forecasts underpinning the RIT-T analysis Generators in relation to payments for additional capacity over and above that which passes the RIT-T (except if underwritten by customers – see later comment).
Addresses first mover issue?	Yes – the amount the generator pays for the extension falls (compared to the generator funding as a stand-alone extension)
Addresses right-sizing issue?	No – unless there is an additional arrangement to facilitate payments by future generators (which would result in some of the risk being underwritten by customers)
Provides generator with certainty over access to the extension?	No

6. Summary of Outcomes under the Different Models

Table 6.1 below summarises key features of each of the models discussed above, ie:

- the application of the RIT-T;
- Model 1; and
- Model 2.

It contrasts these outcomes with the outcomes of the SENE model proposed by the AEMC.

Table 6.1
Summary of Outcomes under Above Approaches

	Who funds the extension?	**Who bears the risk that future generation doesn't materialise?**	**Addresses first mover issue?**	**Addresses right-sizing issue?**	**Provides generator with certainty over access?**
RIT-T (Extension passes the RIT-T)	Customers	Customers	Yes – generators only pay for connection, not for the extension and so the cost falls	Yes – if the generation capacity assumed in the RIT-T and accommodated by the investment reflects the full extent of possible future generation development in that area. No - if there is additional potential generation which would require a larger-sized investment which does not pass the RIT-T.	No – investment is part of the shared network. Access rights are the same as for all other shared network investment.
Extension funded by generator(s), with RIT-T applied to incrementing the capacity. (Model 1)	Generators, up to the stand-alone cost for the first generator (s) Customers fund the incremental cost.	Customers in relation to the incremental portion only. Initial generator(s) bears all of the stand-alone cost if there are no subsequent generators.	No – the first generators pay the stand alone cost.	Partially - future generation would be accommodated up to the point where the additional capacity passes the RIT-T. However this may not reflect the full extent of possible future generation development in that area.	No. Access rights are the same as for all other shared network investments.

	Who funds the extension?	**Who bears the risk that future generation doesn't materialise?**	**Addresses first mover issue?**	**Addresses right-sizing issue?**	**Provides generator with certainty over access?**
RIT-T – with contribution by generator(s)o (Model 2)	Customers for the portion of the investment that passes the RIT-T. Generators for the remaining portion.	Customers in relation to generator forecasts underpinning the RIT-T analysis. Generators in relation to payments for additional capacity over and above that which passes the RIT-T (except if underwritten by customers – see later comment).	Yes – the amount the generator pays falls (compared to the generator funding as a stand-alone extension).	No – unless there is an additional arrangement to facilitate payments by future generators (which would result in some of the risk being underwritten by customers).	No. Access rights are the same as for all other shared network investments.
SENE	Generators (provided forecasts of future generation are correct).	Customers	Yes, since unit costs are lower for first mover.	Yes, although relies on oversight of generation forecasts by AEMO.	Yes (as per AEMC proposal), but only to the extension, not the shared network.

7. Specific Issues with Applying the SENE Framework to the Case Study

The third aim of this case study was to identify practical issues that would need to be addressed in applying the proposed SENE model. This section summarises the issues that have been identified. However, we note that the primary focus of this case study has been the practical application of the RIT-T to an extension in the Eyre Peninsula and the identification and evaluation of alternative models which would represent a more proportionate change in the Rules, compared with the SENE Rules that have been proposed by the MCE in its Rule Change Request.[31] As a result, we have not attempted to identify solutions to the issues identified below.

In summary, the case study has highlighted the following practical issues with applying the SENE framework:

§ **Asset Stranding Risk:**

- The extent of asset stranding in this case depends on the location of future generation, as well as the total MW of generation that is built. If all 2000MW of future generation were to be built close to Cleve, that would result in the stranding of the Cleve-Elliston component of the network extension, despite the total quantum of generation being as forecast.

§ **Size of the SENE extension:**

- Wind generation typically operates at its full capacity for only a limited number of hours over the year. It may therefore not be cost efficient to size a SENE connection to meet 100% of the output of the existing and future connecting wind generators. The SENE framework would need to make provision for the TNSPs to determine the appropriate size of the SENE extension. This in turn will impact the capacity rights which the generators receive.

§ **Capacity rights:**

- The transfer capacity of a line and the ability of a generator to export its energy will vary over time, due to changes in line ratings as well as system stability and system security considerations.
- The SENE framework would need to be explicit as to the form of capacity right given to connecting generators, and in particular whether this is related to a fixed MW of capacity or a percentage of (varying) line capacity.
- Even where a generator is given capacity rights to the SENE, its output may still be constrained by the availability of capacity on the shared network, in the absence of supporting deep network augmentation;

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31 The MCE's Rule Change Proposal references the suggested Rules that were included as an annex to the AEMC's Final Report in relation to its *Review of Energy Market Frameworks in Light of Climate Change Policies.*

- The MCE proposal for a SENE to be partially funded by customers under the RIT-T would appear to make it difficult to also grant generators capacity rights to the SENE.
- The SENE framework would need to set out how capacity rights are treated in the event that the SENE extension becomes part of the prescribed network in future.

§ **The likelihood of load locating in the area.**

- We understand that there is a high probability of load locating in the vicinity of any network extension in the Eyre Peninsula (eg, potential mining load development).
- Future load would reduce the marginal loss factors of generators connected to the SENE and would also reduce the loadings on the SENE, allowing a smaller capacity extension to be constructed, to accommodate the same generation output. An issue that would need to be resolved in further developing the SENE framework would therefore be the implications for the appropriate size of the SENE investment and the associated capacity rights that would be given to the connecting generators, given future load forecasts in the area.

§ **Interconnection between the SENE and the prescribed network:**

- The SENE in the Eyre Peninsula could be built to interconnect with the prescribed network near Port Lincoln, but need not be.
- A network development similar to a portion of the proposed SENE is expected to be needed to support the prescribed network in Port Lincoln at some point in the future, and is currently identified as a contingent project.
- There is therefore a very real issue in this case as to whether the SENE would be converted to regulated status in the future, or whether a duplicate prescribed network would need to be constructed.

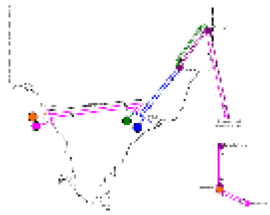
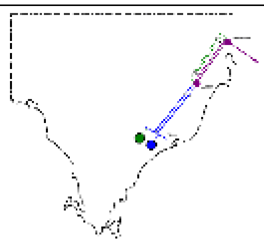
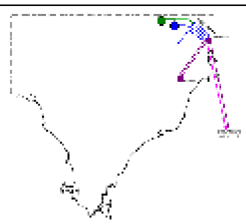
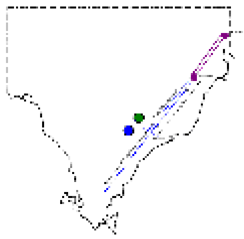
§ **Timing issue:**

- Network assets typically have lives in the order of 50 years, whilst generation assets have lives in the order of 20 years.
- It is not clear how this timing mismatch would be addressed under the SENE framework. Specifically the SENE charges for connecting generators could be calculated on the basis of the generator's own life, or on the (longer) life of the SENE asset itself.

Appendix 1. Indicative RIT-T Analysis: Credible Options

The indicative RIT-T analysis has considered four credible options, as set out in Table A1.1 below.

Table A1.1
Credible Options Assessed

Option	Overview	Network Overview
2000MW – Eyre	This option involves building an extension to connect 2000MW of wind generation on the Eyre Peninsula. It also involves significant investment in the deep network augmentation required to the existing South Australian network to accommodate 2000MW of wind generation. A key feature of this option, as distinct from the other options, is that it involves having to upgrade the current interconnector between South Australia and Victoria to allow sufficient generation to be exported from South Australia.	
1000MW – Eyre	This option involves the connection of 1000MW of wind generation on the eastern side of the Eyre Peninsula. It also requires deep network augmentation to the existing South Australian network to accommodate the connection of 1000MW of wind generation. However, it does not require the upgrade of the current interconnector between South Australia and Victoria.	
1000MW-Northern	This option involves the connection of 1000MW of wind generation in the northern region of the Eyre Peninsula. It also requires deep network augmentation to the existing South Australian network to accommodate the connection of 1000MW of wind generation. However, it does not require the upgrade of the current interconnector between South Australia and Victoria.	
1000MW - Existing	Similar to the second option, this option involves the connection of 1000MW of wind generation on the eastern side of the Eyre Peninsula. However, this option involves bringing forward (and increasing the capacity of) the transmission investment planned for the Eyre Peninsula under the base case. It also requires deep network augmentation to the existing South Australian network to accommodate the connection of 1000MW of wind generation. However, it does not require the upgrade of the current interconnector between South Australia and Victoria.	

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