2019 COGATI Review: Renewable Energy Zones

Response to the AEMC's Discussion Paper

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Energy Networks Australia

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Key messages

- Energy Networks Australia supports greater clarity in the identification of different types of Renewable Energy Zones (REZs) and recognition that models to facilitate REZ development are likely to differ between different types of REZs.
- A key issue relating to REZ development is the need to balance the efficiencies that can be gained by building transmission to facilitate future generator investment (which has the potential to lower costs to consumers overall) with the risks that the projected generation investment occurs later than anticipated (or not at all).
  - This issue currently manifests itself in concerns that efficient REZ development identified outside of the Integrated System Plan (ISP) (via local TNSP planning processes) may in some circumstances be difficult to justify via the Regulatory Investment Test – Transmission (RIT-T).
  - It is also important that any REZ model take into account the longer asset life of transmission investments compared to renewable generators. Any model needs to provide investment certainty across the life of the transmission assets to enable financeability.
- Energy Networks Australia considers that the consideration of REZ models would be better facilitated by further distinguishing between:
  - Type B REZs: where there is a cluster of generators that are connected within the shared transmission network, and are prescribed services paid for by consumers via Transmission Use of System (TUOS) charges (where a RIT-T has been satisfied); and
  - Type C REZs: where there is a cluster of generators that are connected within the shared transmission network, but where the investment may not satisfy the RIT-T and so would be paid for by the generators (rather than consumers) as a negotiated service where they saw benefit in the investment.
- The AEMC's Discussion Paper currently conflates Type B REZs paid for by consumers via TUOS with investments paid for by generators as a negotiated service, with consequences for the assessment of the appropriateness of different models for each circumstance.
- Energy Networks Australia recommends the AEMC gives priority to developing a model for Type B REZs, defined in relation to prescribed services, as these reflect developments identified as efficient from consumers' perspective:
  - Type B REZs may include those identified by AEMO in the ISP as well as those identified by Transmission Network Service Provider (TNSPs) and other stakeholders as a result of local network planning processes.
  - Energy Networks Australia understands that REZs identified as optimal in the ISP will be progressed via the 'actionable ISP' framework currently being

developed, and so sit outside of the models being considered by the AEMC in the Discussion Paper.
  - The focus of the AEMC models for Type B REZs should therefore be on models that facilitate the development of REZs identified by local planning processes outside of the ISP as providing overall lower cost outcomes to consumers.
  - Energy Networks Australia supports further consideration of the bond model for these Type B REZs. The earlier 'Energy Networks Australia model' represents one evolution of this model that could be adopted, once the AEMC's proposed new access framework is in place.
- Energy Networks Australia also supports the development of a model that would facilitate generators funding transmission investment for Type C REZs, for investments that sit outside of the ISP and RIT-T frameworks:
  - This model would have limited applicability but would nevertheless provide an avenue for generators to pay for transmission investment they see value in that may not otherwise occur (either at all, or at the time required by the generator).
  - The AEMC's 'preferred model' appears targeted at this circumstance, although Energy Networks Australia has identified several concerns with this model.
  - Energy Networks Australia suggests that experience in other markets (such as the Auction Revenue Rights arrangements in PJM) may also provide relevant insights in developing models for Type C REZs.
  - It appears likely that models to facilitate Type C REZs would need to be introduced at the same time as (or following) the AEMC's proposed new access arrangements, as they would likely draw provision of hedges to provide an incentive for generators to fund the transmission investment.
- Models that overcome hurdles to Type A REZ development should also be further considered, as the existing arrangements for Identified User Shared Assets (IUSA) cost sharing and Direct Connection Asset (DCA) access raise several practical hurdles that are likely to inhibit this form of REZ development.

Overview

Energy Networks Australia is pleased to make this submission to the Australian Energy Market Commission (AEMC) in response to the discussion paper on Renewable Energy Zones (REZs).

Energy Networks Australia is the national industry body representing Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

The development of REZs has the potential to lower overall costs to consumers

A key issue relating to REZ development is the need to balance the efficiencies that can be gained by building transmission to facilitate future generator investment (which has the potential to lower costs to consumers overall) with the risks that the projected generation investment occurs later than anticipated (or not at all).

This issue currently manifests itself in concerns that efficient REZ development identified outside of the ISP (via local TNSP planning processes) may in some circumstances be difficult to justify via the RIT-T, due to the uncertainties around future generator development.

In this context, key characteristics of REZs not currently explicitly considered in the Discussion Paper are:

» the economics of scale associated with transmission investment, which result in the potential for lower cost outcomes for consumers if transmission is built to accommodate future generation investment, but also raises a stranded asset risk if generator development does not match projections;

» the long-lived nature of transmission investments (40+ years) compared to renewable generation investments (20 years), which makes it important to consider cost recovery risk over the full life of the transmission assets.

More explicit recognition of these characteristics would assist in identifying appropriate models for REZ development that support the most efficient outcomes from consumers' perspective.

REZs that are justified as a prescribed service ('Type B REZs') should be distinguished from REZs funded by generators as a negotiated service

Overall Energy Networks Australia supports the greater clarity provided in the AEMC's Discussion Paper in the identification of different types of REZs, and the recognition that models to facilitate REZ development are likely to differ between different types of REZs.

However, Energy Networks Australia suggests drawing a distinction between Type B REZs that could be justified as a prescribed service under the current planning framework, and REZs that may be funded by generators (or other parties) as a negotiated service where they would not satisfy the RIT-T.

Specifically, Energy Networks Australia considers that the consideration of REZ models would be better facilitated by further distinguishing between:

» Type B REZs: where there is a cluster of generators that are connected within the shared transmission network, and are prescribed services paid for by consumers via TUOS charges (where a RIT-T has been satisfied); and

» Type C REZs: where there is a cluster of generators that are connected within the shared transmission network, but where the investment may not meet the RIT-T and so would be paid for by the generators (rather than consumers) as a negotiated service (ie, a funded augmentation), where they see benefit in the investment.

The AEMC's Discussion Paper currently conflates Type B REZs paid for by consumers via TUOS with investments paid for by generators as a negotiated service,[1] with consequences for the assessment of the appropriateness of different models for each circumstance.

Priority should be given to developing a model for Type B REZs (prescribed service) – with the bond model being considered further.

Energy Networks Australia recommends the AEMC gives priority to developing a model for Type B REZs, as defined above, as these have the potential to result in lower overall costs to consumers.

Type B REZs may include those identified by AEMO in the ISP as well as those identified by the TNSP and other stakeholders as a result of local network planning processes.

Energy Networks Australia understands that REZs identified as optimal in the ISP will be progressed via the actionable ISP framework currently under development, and so sit outside of the models being considered by the AEMC in the Discussion Paper. The focus of the AEMC models for Type B REZs should therefore be on models that facilitate the development of REZs identified by local planning processes (outside of the ISP) as providing overall lower cost outcomes to consumers.

For these REZs, Energy Networks Australia suggests the AEMC gives further thought to whether a variant of the 'bond model' would assist in overcoming current hurdles to their development, applied alongside the existing TNSP planning processes to ensure that developments are efficient from a consumer perspective. This is consistent with the AEMC's view that 'there is merit in pursuing a more limited transmission bond concept as a way of providing additional information for the RIT-T, in a similar way suggested by [Energy Networks Australia] in its submission.'[2] Energy Networks Australia agrees with the AEMC that the model could only inform a RIT-T, not replace it, but considers that this would still be beneficial for the development of Type B REZs and is not a reason to reject the model.

Further, the model put forward by Energy Networks Australia earlier under which generators would be able to enter an auction to purchase the long term hedges created by the investment, essentially represents a variant of the bond model that could be introduced alongside the new access model. This variant would provide an incentive for generators to purchase bonds (to address the free rider problem), and may be an alternative to a restriction on generator connections for a holiday period.

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[1] The AEMC variously refers to Type B REZs as involving the 'shared network' and 'prescribed transmission services', however its preferred model has part of the service provided by the REZ assets being a negotiated service paid for by generators.

[2] AEMC *Discussion Paper Renewable Energy Zones*, October 2019, p. 54.

A separate REZ model that facilitates generators funding Type C REZs should also be considered

Energy Networks Australia supports the development of a model that would facilitate generators funding transmission investment for Type C REZs, for investments that sit outside of the ISP and RIT-T frameworks. Such a model would have more limited applicability but would nevertheless provide an avenue for generators to pay for transmission investment that would not otherwise occur.

The AEMC's preferred model in the Discussion Paper appears to be targeted at this circumstance. Energy Networks Australia notes that this model differs from the model it previously put forward in several material respects, including that it would result in part of the investment being treated as a negotiated service rather than a prescribed service.

Energy Networks Australia has several concerns with the AEMC's proposed model:

- it is unlikely to address incentives for efficient infrastructure, as the arrangements proposed to facilitate investment in incremental 'spare' capacity (including the application of the RIT-T to this incremental portion of the investment only) are likely to be unworkable in practice;
- since this model is proposed to be implemented ahead of the introduction of the AEMC's proposed access reforms, it is not clear how the hedging product would operate. It also does not appear appropriate for a generator to be given a hedge all the way back to the Regional Reference Price (RRP) rather than to the 'other side' of the augmentation associated with the REZ development.
- despite the reference to generators participating in an auction for long-term hedges, it appears that the price of these hedges would be mechanistically determined by the TNSP on a basis that reflects the underlying costs of the investment. This is reminiscent of the AEMC's earlier Optional Firm Access (OFA) proposals, with its associated practical difficulties.

Overall, there are aspects of the AEMC's preferred model that appear to again raise the prospect of a future link between the sale of hedges and transmission investment planning, along the lines that the AEMC has now rejected in its separate Discussion Paper on the access framework.

Energy Networks Australia suggests that further consideration of the AEMC's preferred model should recognise the limited set of circumstances in which this model may ultimately be applied. Energy Networks Australia also suggests that experience in other markets (such as the Auction Revenue Rights arrangements in PJM) may provide relevant insights in developing models for Type C REZs.

Models that could overcome practical barriers to Type A development should be considered further

Finally, models that overcome hurdles to Type A REZ development should also be further considered. The existing arrangements for Identified User Shared Assets (IUSA) cost sharing and Direct Connection Asset (DCA) access raise a number of practical hurdles that are likely to inhibit this form of REZ development. Although the AEMC recognises these issues in its Discussion Paper, it does not propose any steps to address these issues.

Energy Networks Australia considers that the issues relating to Type A REZ development should be actively addressed.

1 Introduction

Energy Networks Australia is pleased to make this submission to the Australian Energy Market Commission (AEMC) in response to the discussion paper on Renewable Energy Zones (REZs).

Energy Networks Australia is the national industry body representing Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

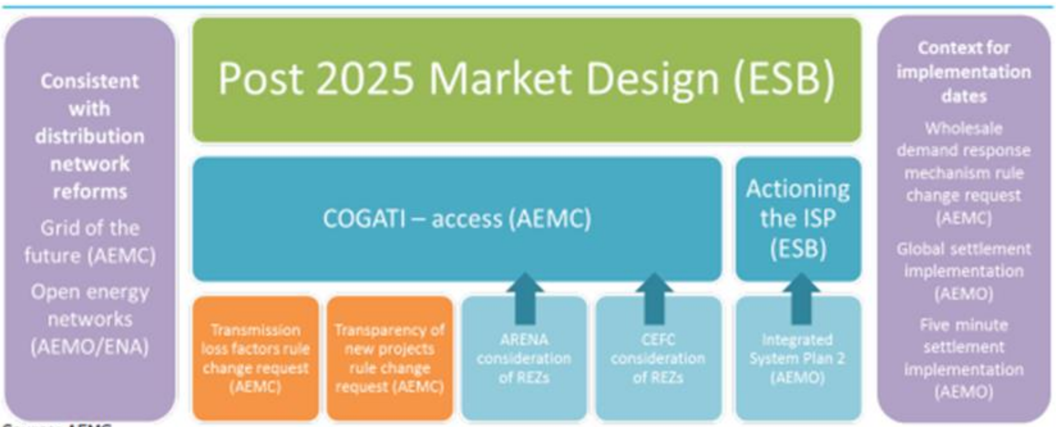
1.1 The proposed REZ models will interact with other areas of the regulatory and planning framework still under development

Energy Networks Australia notes the significant levels of reform currently being undertaken in the sector and that it is responding to this COGATI consultation at a time when the other reform elements that are also expected to impact the development of REZs are also being developed:

» The Energy Security Board's (ESB) governance positions for the 'actionable ISP' and draft rules are expected to be released for consultation later in November;

» ARENA, the Clean Energy Finance Corporation (CEFC) and the ESB are all considering means of facilitating REZs, although the outcomes of these deliberations is not yet clear.

The AEMC's REZ models will interact with other areas of market reform



Source: AEMC

In addition, the Federal Government announced on 30 October an extra $1 billion for the CEFC to 'turbocharge' development of next generation electricity production and to upgrade transmission network to future proof the grid. This announcement is welcomed by Energy Networks Australia. How much of this extra funding might be available to fund REZ gaps or fast track transmission investments is however currently unclear.

In addition, the AEMC's Transparency of New Projects rule change has recently been completed and is expected to gradually improve transparency for future new generator connections. The completeness and transparency of new generator connections in a localised area can help facilitate scale efficient transmission infrastructure and connection arrangements, which could in turn assist in facilitating REZ development.

Energy Networks Australia notes that it will be necessary for the AEMC to consider all of these developments on a holistic basis in determining the appropriate way forward for the REZ models set out in the Discussion Paper.

1.2 Scope of the proposed REZ models in the AEMC Discussion Paper

Energy Networks Australia has clarified with the AEMC that the scope of the models put forward in the AEMC's Discussion Paper is intended to capture:

- REZs that are identified through a RIT-T process arising from TNSP's local planning activities (but which are not included in the ISP); and
- REZs that are identified by a group of generators or other market participants, or by a third party (including governments), and which would not pass a RIT-T.

Energy Networks Australia understands that REZs that are identified in the ISP are expected to be progressed through the 'actionable ISP' framework that is currently being developed by the ESB and is expected to be consulted on later in November. Energy Networks Australia understands that the ISP is identifying REZs that are optimal from a system-wide, least cost perspective, [3] and that these REZs will then be implemented as prescribed transmission services paid for by consumers.[4] Energy Networks Australia assumes that the actionable ISP framework will continue to contain a further evaluation step for REZs identified in the ISP, that confirms that the investment is expected to provide a net benefit to consumers.

Energy Networks Australia also notes that the context for the AEMC's Discussion Paper is that the REZ models could be applied ahead of the changes to the access framework that are also being proposed as part of its COGATI review.[5]

1.3 Structure of this submission

The structure of this submission is as follows:

- Section 2 discusses the AEMC's proposed characterisation of different types of REZs and proposes that a third type ('Type C REZs') also be distinguished to cover REZs that would not be progressed as a prescribed service;

[3] This is consistent with the AEMC's description on p. 10 of the Discussion Paper.

[4] AEMC, *Discussion Paper Renewable Energy Zones*, October 2019, p. 16.

[5] See for example, AEMC, *Discussion Paper Renewable Energy Zones*, October 2019, p. 1.

- Section 3 comments on the issues identified by the AEMC as to why REZs have not been developed under the current framework, and highlights some additional issues for consideration;
- Section 4 responds to the AEMC's preferred model and in particular:
  - highlights that the AEMC's preferred model is most applicable to 'Type C REZs' where generators fund REZs as a negotiated service, for investments that sit outside of the central ISP and local TNSP planning activities;
  - clarifies that the model put forward by the AEMC varies materially from the earlier 'Energy Networks Australia model'; and
  - highlights some concerns with the AEMC's preferred model, and recommends that other alternatives are explored;
- Section 5 recommends that priority be given to developing a model that facilitates development of Type B REZs as a prescribed service, and suggests that the bond model be further considered in this regard (with the earlier Energy Networks Australia model representing a potential future variant of this model);
- Section 6 provides comments on the other models included in the Discussion Paper.

2 The AEMC's characterisation of REZs

The AEMC presents the following characterisation of REZs in its Discussion Paper:

- Type A REZs: a cluster of generators connected to the shared transmission via a (large) DCA. These REZs are connection assets paid for by the connecting party (rather than consumers).
  - Greenfield: where there is a new cluster of generators who want to share connection assets;
  - Brownfield: where new generators want to connect to an existing substation.
- Type B REZs: a cluster of generators within an approximate geographic boundary that are connected within the shared transmission network, and are prescribed services paid for by consumers via TUOS charges (where a RIT-T has been satisfied).
  - Greenfield: an extension of the shared network to a new area with good renewable resources
  - Brownfield: an upgrade and reinforcement of the existing shared network to accommodate an increase in renewable connections.

Q1: Do stakeholders agree with the characterisation of these two types of REZs? Are there any other ways to characterise REZs?

Energy Networks Australia agrees that it is helpful to provide clarity as to what is meant by a REZ and the different circumstances in which a REZ can arise, as this has not always been clear. The characterisation of different types of REZ can also help to identify the different 'REZ models' that may be appropriate to facilitate the development of each type of REZ.

However, in discussing Type B REZs, the AEMC's Discussion Paper variously refers to the transmission investments being provided as 'prescribed services via TUOS' where the RIT-T has been satisfied,[6] and as a negotiated service that generators pay for.[7]

Energy Networks Australia suggests greater clarity could be achieved by drawing a distinction between Type B REZs that could be justified as a prescribed service under the current planning framework, and REZs that may be funded by generators (or other parties) as a negotiated service where they would not satisfy the RIT-T.

Specifically, Energy Networks Australia considers that the consideration of REZ models would be better facilitated by further distinguishing between:

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[6] See for example AEMC, *Discussion Paper Renewable Energy Zones*, October 2019, p. 19 definition of Type B REZ.

[7] See for example AEMC, *Discussion Paper Renewable Energy Zones*, October 2019, p.36, discussion of cost recovery for Type B REZs under the AEMC's preferred model.

- **Type A REZs**: a cluster of generators connected to the shared transmission via a (large) DCA. These REZs are connection assets paid for by the connecting party (rather than consumers).
- **Type B REZs:** where there is a cluster of generators that are connected within the shared transmission network, and are prescribed services paid for by consumers via TUOS charges (where a RIT-T has been satisfied); and
- **Type C REZs:** where there is a cluster of generators that are connected within the shared transmission network, but where the investment does not meet the RIT-T and so would be paid for by the generators (rather than consumers) as a negotiated service (ie, a funded augmentation).

For Type A, Type B and Type C REZs it should be noted that an Identified Shared User Asset (IUSA) is required to cut into the shared network.

The AEMC's Discussion Paper currently conflates Type B REZs paid for by consumers via TUOS with investments ('Type C REZs') paid for by generators as a negotiated service, [8] with consequences for the assessment of the appropriateness of different models for each circumstance.

Separately distinguishing Type C REZs on the basis of whether or not the shared network investment would meet the test to be a prescribed service (ie, pass the RIT-T) is also consistent with how the AEMC has distinguished between Type A and Type B REZs. The assets involved in a Type A greenfield REZ and a Type B greenfield REZ (as defined by the AEMC) are identical, with the key difference being the regulatory treatment (ie, as a Direct Connection Asset (DCA) or as a prescribed service). This is consistent with the AEMC's comment that a particular REZ could be developed as a Type A or Type B REZ.[9]

The AEMC Discussion Paper does not directly refer to the relevance of the RIT-T as part of the current 'planning and investment process' for Type B REZs,[10] which appears to be an omission – although it is alluded to later in the Discussion Paper.[11]

Being clearer that the basis by which different REZ Types are being distinguished is whether they would meet the test for being a prescribed service would help in identifying that issues in applying the RIT-T have been a factor inhibiting the development of greenfield REZs to date. This would in turn highlight the need to address these difficulties either as part of the actionable ISP framework and/or through the REZ models being developed by the AEMC.

[8] As noted above, the AEMC variously refers to Type B REZs as involving the 'shared network' and 'prescribed transmission services', however its preferred model has part of the service provided by the REZ assets being a negotiated service paid for by generators.

[9] AEMC, *Discussion Paper Renewable Energy Zones*, October 2019, p. 22

[10] AEMC, *Discussion Paper Renewable Energy Zones*, October 2019, p. 29.

[11] AEMC, *Discussion Paper Renewable Energy Zones*, October 2019, p. 30.

2.1 Models considered by the AEMC are applicable to different REZ types.

Energy Networks Australia notes that the models put forward by the AEMC in the Discussion Paper in the context of Type B REZs appear in practice to be more applicable to differing types of REZs – as summarised in the following table.

In particular, the AEMC's preferred model appears applicable to what we have termed Type C REZs, where the investment would not otherwise meet the ISP or local TNSP planning criteria.

Energy Networks Australia expands on the assessment of these models in sections 4, 5 and 6 of this submission.

Table 1: Types of REZ applicable to the different models discussed in the AEMC Discussion Paper

	Type A - DCA	Type B – prescribed service	Type C – negotiated service
AEMC preferred model			✓
Open season	✓	✓	
Speculative TNSP		✓	
Risk-sharing model (PIAC)		✓ (ISP REZs)	
Transmission bond model		✓	
Energy Networks Australia model		✓	

3 Issues currently preventing REZ development

The AEMC identifies three issues in the context of facilitating REZs:

1. Incentives to coordinate generation infrastructure: ie, coordination amongst generators
2. Incentives to coordinate generation and transmission infrastructure:
    a. No incentive for generators to fund shared network assets because of the free rider problem ('free rider problem')
    b. Generator remains subject to the risk of not being dispatched when there is congestion, despite making the investment ('dispatch problem')
3. Incentives for efficient transmission investment: No incentive to undertake speculative transmission investment because the costs may not be recovered.

Q2: Do stakeholders agree that these are the relevant issues for REZs? Are there any others? What issues do stakeholders think REZs should address?

The AEMC's framing of the issues that are currently preventing REZ development depends heavily on the perspective of who is willing to fund the transmission infrastructure to REZs. In particular:

» under Issue 2, part of the 'problem' (ie, the free-rider element) is framed as generators not being willing to fund transmission development to REZs under the current arrangements; and

» under Issue 3, the 'problem' identified is that TNSPs are not willing to fund speculative transmission investment - although Energy Networks Australia notes that this 'problem' presupposes that the transmission investment could not be justified as a prescribed service through the application of the RIT-T (and therefore is an issue only for Type A and Type C REZs).[12]

The AEMC refers to its second issue heavily throughout the paper, in assessing whether the alternative models provide an incentive for generators to fund transmission investment. The goal of having generators fund transmission investment appears to be a key implicit objective for the AEMC, regardless of whether the investment being funded is optimal from consumers' perspective[13] (although Energy Networks Australia acknowledges that a concern around whether outcomes will be efficient from a consumer perspective does underpin the AEMC's caution in relation to the bond model – discussed further in section 5.2).

[12] Energy Networks Australia also notes that the disincentive to fund speculative transmission investment relates to the limited upside potential under the current regulatory framework, which does not balance TNSPs' downside exposure.

[13] See for example AEMC, *Discussion Paper Renewable Energy Zones*, October 2019, p. i 'The proposed model provides a way for generators to make a financial contribution to investment in the shared network required for a renewable energy zone.' (investment added).

Energy Networks Australia considers that the AEMC's focus on the 'funding' of the transmission investment relating to REZs arises as a consequence of the conflation of Type B REZs that are funded as a prescribed service and Type B REZs that are funded by generators as a negotiated service (and which Energy Networks Australia suggests should be separately distinguished as 'Type C REZs').

Energy Networks Australia considers that it is important to frame the 'issues' relating to REZ development by reference to the fundamental characteristics of the investment, as it is these characteristics that have also been a barrier to the development of REZs, and that any REZ model also needs to address.

In particular, Energy Networks Australia considers that it is important to take into account:

» the economies of scale and the 'lumpiness' of transmission investment:
  - facilitating coordination between generators and sizing transmission investment to meet future as well as current demand by generators can provide efficiencies (and so lower costs for customers);
  - conversely, undersizing or delayed building of transmission to areas of potential new lower cost generation leads to higher wholesale market costs (and so higher overall costs to consumers);
» Transmission investments are long-lived compared with the lives of renewable generation assets:
  - as a consequence, future market changes (including changes in demand, new technologies and government policies) may impact the operation of the generation associated with the transmission investment, which results in a risk that in future the transmission investment is no longer optimally sized.
» There is a 'chicken and egg' problem, in that renewable generation developers will not spend substantial amounts of money investigating the prospect of new generation developments in area that are currently remote from the grid.

These characteristics of the transmission investment associated with REZs means that it will typically be efficient from the perspective of minimising overall costs for customers to build transmission ahead of generation development. However, this necessarily implies a risk that the investment will not be utilised to its full capacity, which in turn may make the investment difficult to justify under the RIT-T, especially reflecting at the time that may suit the initial connecting generator.

This is a key issue that needs to be addressed in progressing Type B REZs, either through the 'actionable ISP' model (where transmission investments to REZs have been identified by AEMO as part of the optimal system development, which should be sufficient to see their development as a prescribed service) or through the REZ models being considered by the AEMC. Models for Type B REZs that incorporate some form of financial commitment from generators ahead of a decision to proceed with the transmission investment (as a prescribed service) go some way to addressing this issue, as noted by the AEMC at various points in its Discussion Paper.

The substantially shorter lives for renewable generation assets compared to transmission assets also affects efficient REZ development, as models that rely on generator funding either have to allow for the full cost of the transmission investment to be recovered over a shorter period (increasing generation costs), or would imply a future risk for TNSPs which needs to be accounted for under the model.

3.1 Assessment for Type A REZs

Q3: Do stakeholders agree with this assessment of Type A REZs? Have stakeholders experienced issues when connecting to a DCA? If so, have they been managed or is a regulatory solution required for these issues? Are there any other barriers to facilitating a type A REZ?

The AEMC's Discussion Paper highlights that the regulatory framework already allows for the development of Type A REZs (DCAs): via the connection framework, SENE framework and information provisions.

Type A REZs relate to Issue 1 (coordination of generation) and issue 2 (incentives for speculative transmission investment).

The AEMC highlights that the ISP provides information on optimal REZ development areas. Whilst true, Energy Networks Australia notes that the actionable ISP framework is expected to result in these investments being progressed as prescribed shared network development, rather than as DCAs.[14]

The issues relating to REZs represent a barrier to their development as a DCA (ie, coordination of competing generators with different project timing and incentives to build sufficient transmission to achieve economies of scale) – resulting in the existing frameworks only having been used to a limited extent in practice. The AEMC does not put forward any solutions to these issues for Type A REZs.

Energy Networks Australia considers that it remains important to identify whether there are further steps that could be taken to better enable the development of Type A REZs.

3.2 Assessment for Type B REZs

Q4: Do stakeholders agree with this assessment of Type B REZs? Are there any other barriers to facilitating a type B REZ?

The AEMC concludes in its Discussion Paper that: '[t]he main barrier to facilitating a Type B REZ can be considered to be the lack of incentives under the current framework for different generators to collectively fund shared network assets'[15] – due to the free rider problem and dispatch problem.

Energy Networks Australia does not agree with this characterisation for Type B REZs as defined by the AEMC in its Discussion Paper (ie, prescribed investment in the shared network funded by consumers via TUOS). Rather, it considers that this barrier is more relevant to the development of what we have termed Type C REZs, which are REZs that would be funded by generators (or other parties) as a negotiated service (ie, a funded augmentation).

[14] This is consistent with the AEMC's comment on p. 16 of the Discussion Paper.

[15] AEMC, *Discussion Paper Renewable Energy Zones*, October 2019, p.30.

In contrast, Energy Networks Australia considers that currently the main barrier to Type B REZs is the uncertainty around future generation, which makes shared network REZ investment difficult to justify under the RIT-T in some circumstances. Models that provide greater certainty of future generator commitment can help address this problem, in situations where it arises. Energy Networks Australia also expects the actionable ISP model to address this issue for REZs that are identified as part of the ISP.

4 The AEMC's preferred model is applicable to Type C REZs

Q5(b): In particular, do stakeholders think the preferred model should be pursued further?

4.1 The AEMC's preferred model is applicable to Type C rather than Type B REZs

As discussed earlier, the AEMC's Discussion Paper currently conflates Type B REZs paid for by consumers via TUOS with REZ investments paid for by generators as a negotiated service. Energy Networks Australia recommends that REZ investments paid for by generators as a negotiated service should be identified as a separate type of REZ (ie, Type C REZ) to avoid this confusion.

The AEMC's preferred model appears most applicable to these Type C REZs, as a way of facilitating generators funding of transmission investments that sit outside of the ISP and RIT-T planning processes.

In contrast, the model previously put forward by Energy Networks Australia supports the development of Type B REZs which are progressed through the existing planning frameworks as a prescribed service and paid for by consumers via TUOS.

Energy Networks Australia considers that priority should be given to developing a model that facilitates the development of Type B REZs, as these have the potential to lower overall costs to consumers. However Energy Networks Australia also supports the development of a model that would facilitate generators funding transmission investment for Type C REZs, for investments that sit outside of the ISP and RIT-T frameworks. Such a model would have more limited applicability but would nevertheless provide an avenue for generators to pay for transmission investment that would not otherwise occur.

4.2 Energy Networks Australia's understanding of the AEMC's preferred model

Under the AEMC's preferred model, generators can purchase long-term hedges that provides firmer access to the regional reference price (RRP), that then funds the investment in the shared network needed for the REZ.

Energy Networks Australia's understanding from the Discussion Paper of how the model would work is as follows:

- **An initial EOI process** where generators agree to fund a planning study for a REZ. This would be similar to the current SENE process, and is not contingent on the REZ having being included in the ISP;
- A subsequent **financial commitment by generators**: generators would be required to pay a deposit (suggested to be around 50% of the cost of the generator's share of the proposed transmission development). This deposit would be returned if the REZ does not go ahead;
- If the REZ proceeds and the TNSP makes a transmission investment, then the following **cost recovery provisions** would apply:
  - generators pay for their portion as a negotiated service, via the purchase by the generator of a long-term hedge (see below). If generators cover 100% of the cost, the entire investment is a negotiated service and would not enter the TNSP's Regulatory Asset Base (RAB);
  - where there is 'spare' transmission capacity that is not covered by a generator hedge purchase (reflecting the lumpiness of transmission investment and the presence of scale economies), this spare capacity:
    - could be funded by a third party (eg, CEFC, ARENA, government). There would presumably be an arrangement for repaying this third party as generators connect, although the Discussion Paper is silent on this.
    - could be built as a speculative investment by the TNSP (and recovered from subsequent generator connections where those eventuated). This investment would be a non-regulated investment, and subject to the rate of return required by the investor.
    - could be recovered from customers as a prescribed service, where it passes the RIT-T (which would be applied to the incremental spare capacity portion only), with the incremental capacity entering the TNSP's RAB.
- In return for the initial financial commitment, generators would have the right to **purchase long-term transmission hedges** where the REZ proceeds:
  - The hedge would be to the RRP;
  - The hedge would be close to the same length as the generator's investment, or sufficiently long to be commensurate with the cost of the investment made by the generator.
  - The hedge price would be calculated manually by the TNSP for each REZ project.[16]

[16] Energy Networks Australia notes that the Discussion Paper refers to the generator having the right to 'participate in an auction' for the long-term hedge. However the more detailed description in the paper appears to be based on the hedge price being determined by the TNSP on an administrative basis, related to the cost of the investment, rather than via an auction.

- The price would be paid over the course of the hedge period in instalments.

- The AEMC states that this model would work alongside the usual AEMO and TNSP planning processes. However it is not clear how its model would interact with the actionable ISP framework for REZ investments identified in the ISP, or the RIT-T framework for investments identified as part of TNSPs' local planning processes.

The AEMC notes in its Discussion Paper that this mechanism could be extended to other investments in the transmission network in addition to REZs and calls for stakeholder views on this possibility.

4.2.1 The AEMC's preferred model differs fundamentally from the model put forward earlier by Energy Networks Australia

The presentation of the AEMC's preferred model in the Discussion Paper immediately follows the AEMC's description of the 'ENA Model' as put forward in an earlier Energy Networks Australia submission. This gives the impression that the AEMC's preferred model is a variant of the model proposed by Energy Networks Australia.

The model now being put forward by the AEMC has very little in common with the model put forward by Energy Networks Australia.

The earlier model was put forward by Energy Networks Australia in the context of the AEMC's proposal to use Financial Transmission Rights (FTRs) to drive the expansion of the transmission network – a proposal which the AEMC has now dropped – as a more workable alternative to that proposal. As such, the model assumed the implementation of the FTR element of the AEMC's access proposal and was not put forward in the context of REZ development as a model that could be adopted ahead of the implementation of that access regime.

Key areas of difference between the 'Energy Networks Australia model' and the model the AEMC has now put forward are:

» The Energy Networks Australia model operated alongside the actionable ISP and RIT-T processes, with efficient transmission investment being identified and progressed through those processes.
  - Having generators signal their interest in committing to a REZ via the proposed deposit in the Energy Networks Australia model would assist the application of the RIT-T (as it provides greater assurance that generators will connect).

» In the Energy Networks Australia model, the entire transmission investment is provided as a prescribed service (and therefore needs to pass the RIT-T).
  - There is no negotiated service component of the investment, in contrast to the AEMC model.

» Any revenue raised from generators from the auction of long-term hedges would be used to offset consumer TUOS charges.

» Generators contributions are determined on the basis of an auction of the long-term hedges created by the investment (rather than a mechanistic 'hedge price' set by the TNSP, which appears to be the proposal under the AEMC's preferred model).

4.3 The AEMC's model raises some concerns and other options should be explored

Energy Networks Australia consider that the AEMC's preferred model raises a number of concerns and suggests that other models that may overcome the issues associated with Type C REZ development are also considered by the AEMC.

In particular the AEMC's preferred model is unlikely in practice to address incentives for efficient infrastructure:

- As noted earlier, a fundamental characteristic of REZ investment is that the potential economies of scale and the lumpiness of the transmission investment mean that it is efficient for transmission to be built to accommodate future generator connection.
- The mechanism for this (efficient) 'spare capacity' to be developed under the AEMC model essentially relies on funding from third parties, as the other two avenues identified by the AEMC are unlikely to be workable in practice:
  - the AEMC already identifies as its third issue hindering REZ development, that TNSPs have been unwilling to make speculative investments; and
  - since by definition the additional generation needed to justify the incremental investment under the RIT-T is uncertain, this investment is unlikely to pass the RIT-T.[17] The concept of applying a RIT-T to the 'incremental' investment (rather than the entire investment) also raises a number of practical issues that further lessen the chance of the incremental portion alone passing the RIT-T.[18]

In addition:

- It is not clear whether the long-term hedge price would recover the cost of the associated transmission investment over its entire life (which will be longer than the renewable generator life) or leaves the TNSP exposed to cost recovery risk for the latter period of the investment.
  - Even if the intention is for the costs to be recovered over the period of the initial connecting generators' lives, TNSPs would still be exposed to cost recovery risk where a generator exited the market earlier than the period used to calculate the generator contribution via the hedge price (due, for example, to a change in market circumstances);
- Despite the reference in the Discussion Paper to generators participating in an auction for long-term hedges, it appears that the price of these hedges would be mechanistically determined by the TNSP on a basis that reflects the underlying

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[17] As it is in addition to the generation that has indicated its interest via a financial commitment, and the REZ falls outside those identified in the ISP (which the AEMC Discussion Paper indicates will be pursued as a prescribed investment, rather than under this model).

[18] For example, where the 'spare' capacity reflected the lumpiness of transmission investment, then there would be a cost for this incremental capacity in the RIT-T assessment, but no corresponding benefit.

costs of the transmission. This approach appears reminiscent of the AEMC's earlier OFA proposals, with their associated practical difficulties;

» Since this model is being implemented ahead of the introduction of dynamic regional pricing and the access reforms,[19] it is not clear how the hedging product would operate in practice. It does not appear consistent for the hedge to reflect the extent of congestion all the way back to the RRP (which may be some way from the REZ), rather than simply to the point at the other side of the constraint that the REZ investment has built out; and

» The AEMC's model appears to result in the same investment potentially being treated as partially providing a negotiated service and partially as a prescribed service, which has implications for the allocation of O&M and repex expenditure associated with the investment.

Further, the concept of applying this model to other transmission investments more broadly appears to re-introduce a linkage between the sale of FTRs and transmission investment, which the AEMC has now decided not to pursue as part of its proposed firm access reforms. Energy Networks Australia would counsel against re-prosecuting this linkage as part of the REZ model design.

Energy Networks Australia suggests that any further consideration of the AEMC's preferred model should recognise the limited set of circumstances in which this model may ultimately be applied. Energy Networks Australia also suggests that experience in other markets (such as the Auction Revenue Rights arrangements in PJM) may provide relevant insights in developing models for Type C REZs.

[19] The AEMC comments in several places in its Discussion Paper that the proposals for REZs can be implemented earlier than the changes required to implement its proposed access model, and are a 'simpler, more discrete' application (see for example p. i, p. 1).

5 Priority should be given to developing a model for Type B REZs (ie, prescribed service)

Q5(a): What are the stakeholders' views on the five models presented in this paper for REZs?

Whilst supporting the development of a model that would facilitate generators funding transmission investment for Type C REZs, Energy Networks Australia recommends the AEMC gives priority to developing a model for Type B REZs (defined as a prescribed service), as development of these REZs has the potential to lower overall costs to consumers.

Type B REZs include those identified by AEMO in the ISP as well as those identified by the TNSP and other stakeholders as a result of local network planning processes.

Given Energy Networks Australia's understanding that REZs identified as optimal in the ISP will be progressed via the actionable ISP framework, the focus of the AEMC models for Type B REZs should therefore be on models that facilitate the development of REZs identified outside of the ISP process as providing overall lower cost outcomes to consumers.

For these REZs, Energy Networks Australia urges the AEMC to give further thought to whether a variant of the 'bond model' would assist in overcoming current hurdles to their development, applied alongside the existing TNSP planning processes to ensure that developments are efficient from a consumer perspective.

5.1 Description of the transmission bond model

Under the transmission bond model as described in the AEMC's Discussion Paper, potential REZs could be identified through the ISP or TNSP planning processes:

- Generators can enter into a contractual agreement with the TNSP to demonstrate commitment to a particular REZ, to lower the risk of speculative investment.
- TNSP could 'approach the AER'[20] with greater certainty about generation development. Although the Discussion Paper does not make this clear, Energy Networks Australia assumes that this is a reference to the TNSP applying the RIT-T and being better able to justify the use of market development scenarios in which the generation does connect at the REZ.

The TNSP then issues transmission bonds of sufficient value to cover the estimated cost of the augmentation ($/MW notional capacity).

- If sufficient bonds are sold to cover the cost of the investment, then the augmentation proceeds.
  - On completion of the investment:
    - if a generator connects, the value of its bond is returned

[20] AEMC, *Discussion Paper Renewable Energy Zones*, October 2019, p.51.

- if a generator does not connect, the bond is forfeited and used to offset the TUOS costs for consumers.
  - other generators are not allowed to connect to the investment for a fixed period (eg 3 years), in order to provide an incentive for generators to provide a bond.
- If insufficient bonds are sold, the investment may not proceed and the bonds are returned to generators.

The AEMC notes in the Discussion Paper that governments could potentially also purchase bonds as a mechanism to subsidise the transmission investment (with the money raised being used to offset TUOS). Similarly, it appears open to the CEFC to also purchase bonds to assist development of these REZs.

5.2 The bond model can lower the risk borne by consumers associated with uncertainty over future generation development

Energy Networks Australia notes that this model could be applied to prescribed REZ investments (ie, Type B REZs), to reduce the risk borne by consumers relating to funding transmission investment that may ultimately not be used.

The sale of bonds allows greater weight to be placed on scenarios in which the generators connect, when applying the RIT-T, in the absence of other factors that the TNSP is able to point to for a specific RIT-T to justify the weight given to these scenarios. The paying of a bond essentially increases the certainty that the generator does intend to locate at that REZ.

Moreover, since generators forfeit their bond if they did not connect to the new REZ, this would reduce the costs borne by consumers for any unused capacity.

Energy Australia notes that the extent to which bonds may be required in order to address uncertainty regarding generator investment will depend on the specific circumstance of each RIT-T. The test of whether 'sufficient' bonds have been sold is therefore necessarily one that would need to be subject to TNSPs' judgement based on what other information was available to inform the RIT-T assessment, and should not be reflected in the model as a 'hard constraint'.

The AEMC expresses concern in the Discussion Paper that this model may justify transmission investment that is not optimal from a system-wide perspective (and that consumers would pay for this higher cost outcome, as transmission costs get reflected in TUOS charges in this model if the investment proceeds).[21]

The AEMC's concern appears to arise as a consequence of considering this model in the context of Type C REZ development. Where it is applied in the context of a prescribed service, the TNSP would continue to apply the RIT-T to justify the investments as being optimal. As a consequence, the test for the investment to proceed remains passing the RIT-T, but that is facilitated by the greater certainty that there will be generators locating at the REZ as signalled through their bond purchase (and through the bonds being used to reduce consumers' costs if the generators do not connect). This is consistent with the AEMC's view that 'there is merit in pursuing a more limited transmission bond concept as a way of providing additional information

[21] AEMC, *Discussion Paper Renewable Energy Zones*, October 2019, p.53.

for the RIT-T, in a similar way suggested by [Energy Networks Australia] in its submission.'[22] (Discussion Paper, p. 54)

Energy Networks Australia agrees with the AEMC that the model could only inform a RIT-T, not replace it, but considers that this would still be beneficial and is not a reason to reject the model.

This model reflects the CREZ model which has been adopted in Texas and has been instrumental in that market in underpinning the development of new transmission associated with REZs. Energy Networks Australia believes that this model is worth further consideration by the AEMC.

[22] AEMC, *Discussion Paper Renewable Energy Zones*, October 2019, p.54.

5.3 Alternative approaches

Q5(c): Are there any other ways of addressing the 3 issues identified in this paper that have not been considered?

Energy Networks Australia notes the AEMC's concern under the bond model about the delay imposed on other generators connecting (in order to address the free rider problem). The AEMC is also concerned that it may be difficult to implement this kind of restriction in practice, since generators could still benefit from the augmentation where they connect somewhere else within the meshed network.

Energy Networks Australia recognises the AEMC's concerns. Rather than imposing a restriction on subsequent generators connecting, the model could be combined with the right to bid to obtain long-term hedges associated with the investment, in order to provide a positive incentive for generators to provide a bond.

This variant of the bond model is in essence the model put forward by Energy Networks Australia in its earlier response. However, Energy Networks Australia notes that this model was proposed in the context of dynamic regional pricing and FTRs being implemented. REZ development on the basis of this variant of the model could therefore only occur once the changes to the access framework have been made, rather than ahead of that framework being introduced.

6 Other alternative models considered by the AEMC

Q5(a): What are the stakeholders' views on the five models presented in this paper for REZs?

As set out in the table in section 2, Energy Networks Australia considers that the other models discussed by the AEMC it the Discussion Paper are relevant to different types of REZs.

6.1 Open season approach

Under the open season approach there would be a clustering of group consideration of connections to facilitate coordinate of generator connections to achieve efficient outcomes.

The AEMC considers that this model would most likely apply to Type A REZs only, as generators continue to have little incentive to fund assets on the shared network (due to the free rider and dispatch issues). The AEMC is concerned that in the current environment this approach could delay inappropriately connections.

Energy Networks Australia notes that an open season approach could be used to provide greater certainty that generators will connect to a REZ, and so could assist the application of the RIT-T to justify the investment in Type B REZs as a prescribed service. However alternative models of generator commitment (such as the earlier Energy Networks Australia model, or the bond model) may be more effective in this regard.

6.2 Speculative investment by TNSP

Under this model a similar mechanism to the speculative investment fund in the National Gas Rules could be introduced. This would allow speculative transmission investment that ends up being prudent and efficient to enter the TNSPs' RAB, including a higher rate of return earned for the period prior to the roll-in (determined by the AER).

The AEMC largely rules out this model in the Discussion Paper as inconsistent with the legislation on the binding rate of return, and so requiring law changes.

Energy Networks Australia notes that providing a greater incentive for speculative investment would be consistent with the additional risks such investment would entail. However it recognises the AEMC's concerns about achieving the legislative changes necessary to implement such a model.

6.3 Risk-sharing model (PIAC)

The AEMC's Discussion Paper outlines a further variant of the model that has been proposed by PIAC several times during this COGATI review.

Energy Network Australia's understanding of the variant of the PIAC model discussed in relation to REZ investments is that it would apply to Type B REZs. These REZs would be ones that have been identified as 'efficient' through the AEMO ISP process, or by industry or government. The model incorporates a RIT-T (or equivalent process) to determine the efficient network capacity. Energy Networks Australia notes that the PIAC model therefore would need to dovetail with the actionable ISP framework, and appears to sit outside of the scope of the REZ models being considered by the AEMC.

Under this model, the recovery of capex for REZ is apportioned between generators and consumers rather than just consumers.

The amount apportioned to generators is determined by the AER or government. This amount is initially funded by a 'speculative generator'[23] (and may be underwritten by government):

» The speculative generator is appointed via a contestable process (such as a reverse auction), based on the investor that requires the lowest return;
» The speculative generator recovers its costs through connection charges as generators connect;
» Connection charges are subject to a cap imposed by the AER and increase over time according to a speculative rate of return factor, to incentivise generators to connect as early as possible;
» The speculative investor can also invest in capacity above the efficient level on an unregulated basis.

TNSPs incorporate the customer portion of the investment in its RAB and recovers all of the opex associated with the investment through TUOS. TNSPs recover the cost for the remaining portion of the investment directly from the speculative generator.

Energy Networks Australia notes that previously the PIAC model had the TNSP as the party that bore cost recovery risk under this model where the amount of generation connecting to use the investment was less than anticipated. The latest variant now has a 'speculative generator' bearing this risk.[24]

Energy Networks Australia is supportive of the recognition that it would not be appropriate for the TNSP to bear the risk under this model.

However, Energy Networks Australia also notes that the new variant of the PIAC model depends on there being a party (or government or government agency (eg, CEFC)) who is willing to bear this risk. In the absence of a party willing to fund the speculative portion of the investment, the investment would not proceed, even where it has been identified as efficient in the ISP.

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[23] Energy Networks Australia notes that the term 'speculative generator' is used in the AEMC's Discussion Paper, but that in practice it would appear open to any speculative investor to play this role.

[24] Energy Networks Australia notes that the Discussion Paper still refers to TNSPs bearing this risk in some places (eg, p. 48), but assumes this is unintentional.

AEMC does not consider that the PIAC model addresses the free rider and dispatch issues. Energy Networks Australia agrees with this assessment, and sees the PIAC model largely as relating to alternative arrangements for cost recovery for investments that have been determined under a separate process (ie, ISP/RIT-T or an equivalent) to be efficient and which would otherwise still proceed and be paid for by consumers via TUOS.