Australian Energy Market Commission

DISCUSSION PAPER

RENEWABLE ENERGY ZONES

14 OCTOBER 2019

REVIEW

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

SUMMARY

1 In order to support the transition of the electricity system, the transmission network will need to develop to efficiently connect and transport large amounts of energy from dispersed renewable generation across the NEM, which is locating in different places to where generation has historically located, to where consumers want to use it.

2 Renewable energy zones are a useful first step on the path of more holistic access reform and can be implemented earlier than those changes required to implement our proposed access model.

3 The concept of a 'renewable energy zone' is not defined in the existing regulatory framework, and is used by different parties to describe different ideas and concepts, depending on what a particular party wants to achieve and do.

4 This paper seeks to provide some clarity as to the different ways renewable energy zones can be characterised, how these can be achieved under the current framework, the various issues that arise under those different characterisations, and how they can be better facilitated in the future.

5 Renewable energy zones can be characterised in two broad ways. In this paper we describe these as type A renewable energy zones and type B renewable energy zones.

6 Type A is a cluster of generators sharing connection assets only, which are those assets used by generators to connect to the transmission network. Type A renewable energy zones can already be facilitated under the current regulatory framework. To the extent that these opportunities are not being pursued, it is often due to factors outside the regulatory framework such as commercial and confidentiality considerations.

7 Type B is a cluster of generators sharing their connection assets as well as a part of the shared transmission network. The shared transmission network are those assets that facilitate the flows of electricity between all parties that produce and consume electricity i.e. facilitate flows to consumers. The key difference between type A B REZs is that type B includes assets that are used to facilitate flows to consumers directly, whereas type A REZs do not.

8 There are ways that both type A and B REZs can occur under the current framework. However, one of the main barriers to facilitating type B renewable energy zones is that there are no incentives under the current framework for generators to collectively fund assets for the shared transmission network. A generator that invests in the shared transmission network faces a free-rider problem and a risk of not being dispatched, despite the investment.

9 This paper presents a model that seeks to facilitate type B renewable energy zones and overcome the free-rider problem.

10 The proposed model provides a way for generators to make a financial contribution to investment in the shared transmission network required for a renewable energy zone. In return for that investment, the generator receives a long-term hedge that provides some guarantee about its financial return for making that investment.

11 This model would work alongside the usual transmission planning and investment decision-making processes undertaken by AEMO and TNSPs.

12 The outcomes of consultation on this paper will form an input into the COGATI review recommendations to the Energy Security Board in December 2019. The discussion and conclusions in this discussion paper are consistent with the proposals for dynamic regional pricing and financial transmission rights discussed in the accompanying COGATI access discussion paper that has been published alongside this paper.

13 The Commission is holding a workshop on this reform on 18 October in Melbourne. Stakeholders should register via the Commission's website.

14 The Commission invites comments from interested parties in response to this paper by 8 November 2019. All submissions will be published on the Commission's website, subject to any claims of confidentiality.

15 We also welcome meetings with stakeholders. Stakeholders wishing to meet with the AEMC should contact Russell Pendlebury at russell.pendlebury@aemc.gov.au.

CONTENTS

1	**Introduction**	**1**
1.1	Terms of reference	1
1.2	Purpose and scope of this review	1
1.3	Purpose of this paper	2
1.4	Interaction with other key reforms under way	2
1.5	Review timeline	3
1.6	Submissions	4
1.7	Workshop	4
1.8	Structure of the report	5
2	**Context**	**6**
2.1	Background	6
2.2	Current framework	7
2.3	Current transmission services	11
2.4	Work programs considering REZs	15
3	**Coordination of generation and transmission for REZs**	**18**
3.1	Defining REZs and the issues to be addressed	18
3.2	Characterising two types of REZ	18
3.3	Summary of the issues relating to REZs	22
3.4	Type A REZ	23
3.5	Type B REZ	28
4	**Proposed model for REZ development**	**32**
4.1	Introduction	32
4.2	Proposed model: Long-term hedges to fund transmission assets	33
4.3	Conclusions on all models	39
	Abbreviations	**40**

APPENDICES

A	**Other models for developing renewable energy zones**	**41**
A.1	Model 2: Open season approach	41
A.2	Model 3: Speculative investment by TNSP	43
A.3	Model 4: Risk-sharing model (PIAC model)	46
A.4	Model 5: Transmission bond model	51

TABLES

Table 4.1:	Models mapped against REZ type and issues	32

FIGURES

Figure 1.1:	Interaction with other key reforms	3
Figure 1.2:	COGATI review indicative timeline	4
Figure 2.1:	Transmission system assets	13
Figure 3.1:	Integrated System Plan REZs	21
Figure 4.1:	Summary of model 1	38
Figure A.1:	Summary of model 2	43
Figure A.2:	Summary of model 3	45
Figure A.3:	PIAC risk sharing model	49

Figure A.4:	Summary of model 4	51
Figure A.5:	Summary of model 5	55

1 INTRODUCTION

1.1 Terms of reference

The *Coordination of generation and transmission investment* (COGATI) review is focussed on examining *when* the transmission frameworks will need to change, and, if so, *what* they will need to change to. This review is undertaken pursuant to terms of reference received in 2016 from the Council of Australian Governments (COAG) Energy Council, which asked the Australian Energy Market Commission (AEMC) to implement a biennial reporting regime on these matters.[1]

The inaugural COGATI review commenced in early 2017, and concluded with its final report being published in December 2018 (inaugural COGATI report). This final report concluded that change to the transmission frameworks is needed at the present time so that our regulatory frameworks evolve to match the transition under way in the NEM.[2]

Given that the AEMC is to report biennially, the second COGATI review commenced on 1 March 2019 with the publication of a consultation paper.[3]

1.2 Purpose and scope of this review

The current review has two key focusses:

1. developing the specification of the **proposed access model**, which implements dynamic regional pricing and financial transmission rights
2. facilitating **renewable energy zones**, which are a useful first step on the path of more holistic access reform and can be a simpler, more discrete implementation than reforming the access regime.

The second focus is the subject of this paper. The first focus on the proposed access model is the subject of the accompanying paper.

The Commission will conclude the current review in December 2019 by providing the COAG Energy Council with a proposal of changes to the rules to embed and implement the proposed reforms. This proposal will include recommendations relating to both transmission access and renewable energy zones.

The Commission is also working with the Energy Security Board (ESB) and other market bodies to report back to the COAG Energy Council in 2019 on renewable energy zone connections, access and congestion, as well as the broader process underway on *Actioning the ISP*.[4] The outcomes of consultation on this discussion paper will form an input into the ESB's recommendations to the COAG Energy Council in December 2019.

1 The terms of reference were provided under section 41 of the National Electricity law (NEL) and can be found here: https://www.aemc.gov.au/sites/default/files/content/97164a7b-09bf-49fb-9f2e-f6b996f5a96b/Reporting-on-drivers-of-change-Terms-of-Reference.PDF

2 The final report is available from the AEMC website at https://www.aemc.gov.au/sites/default/files/2018-12/Final%20report_0.pdf

3 The consultation paper is available from the AEMC website at https://www.aemc.gov.au/sites/default/files/2019-03/Consultation%20paper_0.pdf

4 See recommendation 12 of the ESB's *Integrated System Plan; Action Plan,* December 2018.

It is anticipated that the proposed changes to the rules will be submitted to the Commission to be progressed through the rule change process in early 2020. In addition to the stakeholder engagement opportunities in this review detailed below, there will be numerous opportunities for further detailed stakeholder engagement next year when the Commission assesses the reforms through any submitted rule change requests.

1.3 Purpose of this paper

Renewable energy zones could be a useful first step on the path of more holistic access reform and can be a simpler, more discrete implementation than reforming the access regime.

Considering ways to facilitate renewable energy zones through a separate work stream allows the Commission and stakeholders to focus on the changes needed to the regulatory framework to facilitate renewable energy zones. These would work in conjunction with identification and implementation of renewable energy zones through the ISP.

These changes may be able to be made faster than those changes required to implement full access reform.In addition, in response to the directions paper, a number of stakeholders suggested that the issues relating to renewable energy zones need to be considered through more focused consultation.[5]

For these reasons, the Commission has set up a separate work stream focussing on facilitating renewable energy zones and published this separate discussion paper. While still forming part of the COGATI project, the publication of a separate discussion paper aims to distinguish more clearly between:

- those issues that relate solely to access reform,
- those issues that relate solely to the development of renewable energy zones, and
- those issues that relate to both areas of reform.

Although many of the issues are interrelated, some of the issues are more specific to renewable energy zones than to access reform more broadly, and so there is some merit in pursuing these issues through a separate work stream.

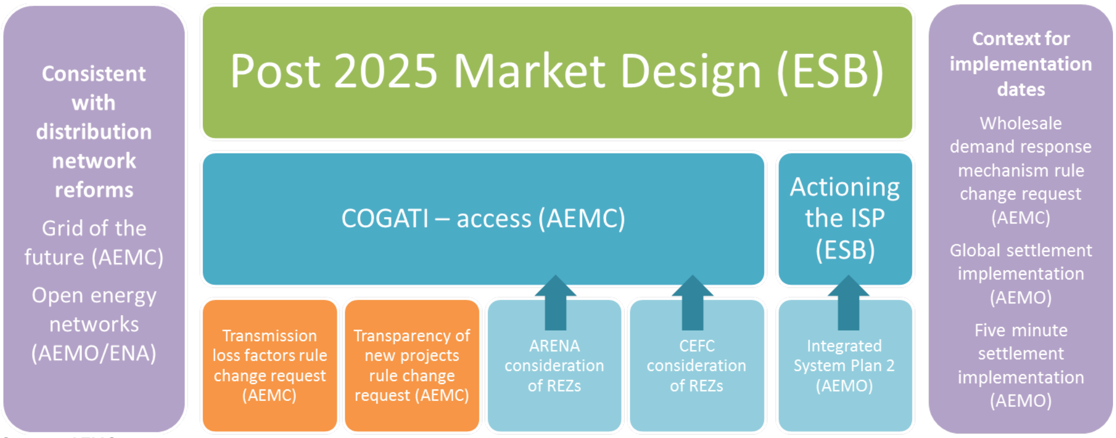
The discussion and recommendations in this discussion paper are consistent with the proposals for dynamic regional pricing and financial transmission rights, as discussed in the accompanying COGATI discussion paper.

1.4 Interaction with other key reforms under way

This review is being conducted within the context of a broader reform agenda being pursued by the market bodies and the Energy Security Board. Related reforms are summarised in Figure 1.

5 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, directions paper submissions: ENA, p. 9; AEMO, p. 4.

Figure 1.1: Interaction with other key reforms



Source: AEMC

The AEMC is working closely with the above market bodies and the Energy Security Board to make sure that the various reforms under way are coordinated. Further detail on how key projects relate to each other is contained in Chapter 2.

1.5 Review timeline

The review timeline for 2019 is summarised below. The Commission has amended the project timeline in response to stakeholder feedback to the June directions paper. Many stakeholders expressed support that the access frameworks need to change now. Others expressed support for the intention of our proposed model, including that it could provide signals for efficient dispatch of generation and more efficient generator locational decisions, as well as increased certainty of access to transmission network capacity.

However, stakeholders asked for more details on how the dynamic regional pricing and financial transmission rights would operate. Some stakeholders also requested more focussed consultation on renewable energy zones and how they can be used as a transitional measure.

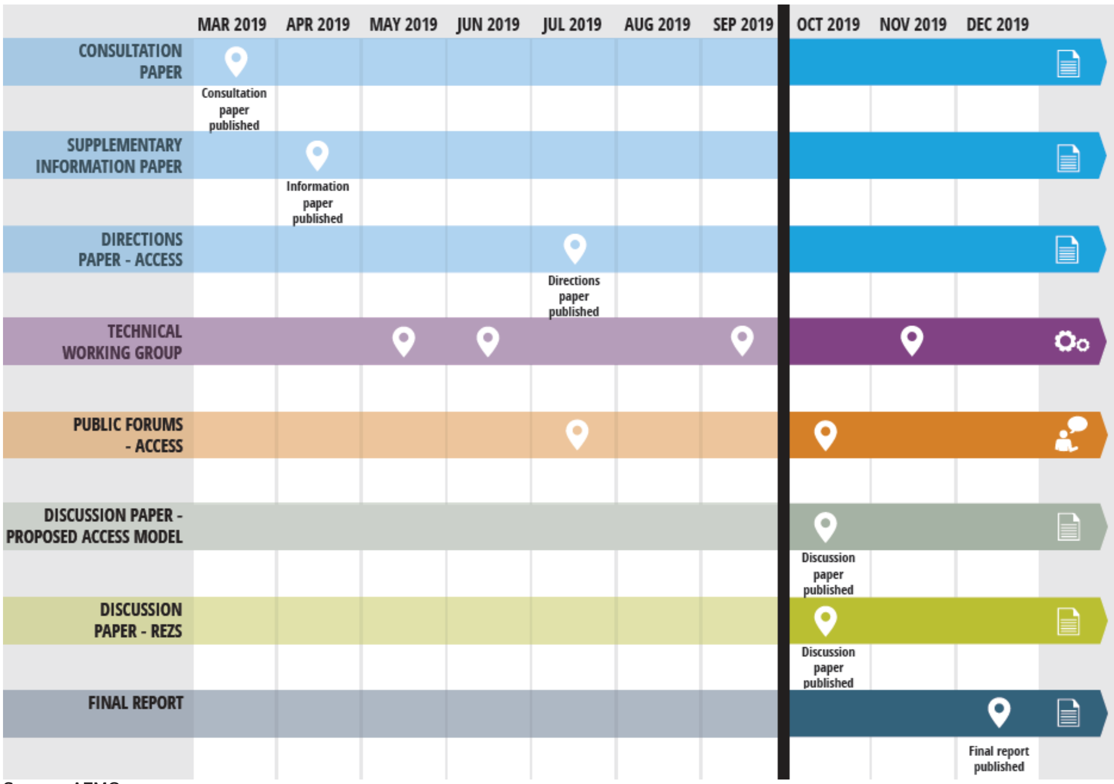
Therefore, the Commission has revised its approach in order to publish two papers:

1. a separate paper, which provides a specification of the proposed access model, including dynamic regional pricing and financial transmission rights
2. this paper, a discussion paper on renewable energy zones.

These papers will be followed by the publication of a final report in December 2019.

In addition, we have formed a technical working group for this project. The group has met three times to date, and will meet again in November 2019.

Figure 1.2: **COGATI review indicative timeline**



Source: AEMC

1.6 Submissions

Written submissions on this discussion paper must be lodged with the Commission by 8 November 2019 via the Commission's website, using the 'lodge a submission' function and selecting the project reference code EPR0073. The submission must be on letterhead (if submitted on behalf of an organisation), as well as signed and dated.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions. The Commission publishes all submissions on its website, subject to a claim of confidentiality.

All enquiries on this paper should be addressed to Russell Pendlebury at russell.pendlebury@aemc.gov.au.

1.7 Workshop

The AEMC will hold a workshop in Melbourne on 18 October 2019 to work through the proposed access model and renewable energy zones.

Interested participants should register for this event by visiting the AEMC website.

1.8 Structure of the report

The remainder of the paper is structured as follows:

- chapter two sets out background and context for renewable energy zones
- chapter three discuses the nature of renewable energy zones, and the issues that they can identify
- chapter four sets out a preferred model to facilitate renewable energy zones
- appendix A discusses other models that were considered.

2 CONTEXT

2.1 Background

Australia is very large, and the national electricity market (NEM) is a long and sparsely connected power system, with concentrated load centres that are distant from one another. The current regulatory framework, and consequently the transmission network, was primarily designed to connect large centres of thermal and hydro generation to major demand centres some distance away.

The electricity sector transition that is currently underway is changing the dynamics of the power system:

- Traditional thermal plants are closing, and more renewable and asynchronous generators are connecting to the power system with these newer plants having a different generation profile. In addition, the introduction of 5 minute settlement reforms will further incentivise more flexible types of generation technologies over the coming years, particularly large-scale storage.
- The networks across the NEM are becoming more meshed and interconnected (both with and across regions), with this being combined with increased inter-regional trade and sharing of reserves between jurisdictions.

Generation roughly equal to the current size of the NEM (50 GW) is foreshadowed for connection to the grid over the next 10 years. The NEM will replace most of its current generation stock by 2040. Unlike the existing power system, the system of the future is likely to be characterised by a large number of relatively small and geographically dispersed generators. Further, these generators are unlikely to be located where there is substantial existing transmission to serve them instead being connected in sunny or windy areas at the edges of the grid, where the network is less strong. In addition, these new types of generation can in general be built more quickly than transmission infrastructure required to serve it. Substantial and timely transmission infrastructure is therefore likely to be required.

This trend is only going to continue. AEMO's Integrated System Plan in the 'neutral with storage' modelling scenario shows that by 2030 over 6,000 MW of existing generation is expected to close and be replaced by approximately 22,000 MW of renewable generation and 6,000MW of storage. By 2040, the amount of expected closure increases to approximately 16,000 MW, which is projected to be replaced by 50,000 MW of renewable generation and 20,000 MW of storage.

If a faster and bigger transformation occurs, then these values will increase and occur sooner.

Many of the current applications for connection to the grid are located at the periphery of the transmission network, where access to renewable fuel sources is good but the network is weak, in terms of both capacity and system strength. In addition, multiple proponents are seeking to connect in similar locations, but on different time frames.

In light of the electricity market transition, prospective generators and storage require greater certainty that their assets can remain profitable even if subsequent parties connect to the network and create congestion or adverse loss effects. Currently, since a generator's revenue from the wholesale market is determined by how much it is physically dispatched for, when it is not dispatched due to congestion (such as someone locating next to it), it receives no revenue.[6] In practice, this means that given the scale of connections, generator's expectations of future revenue are being changed through the pace of transition. Prospective generators require and want greater certainty that their assets can remain profitable even if subsequent parties connect to the network and create congestion.

These changes mean that there is a need to have a better way of co-ordinating generation and transmission investment decisions in order to better facilitate the transition that is occurring. This is the focus of the proposed access model, but renewable energy zones can also assist.

2.2 Current framework

Before considering potential changes that may be required to the regulatory framework in order to facilitate renewable energy zones (REZs) in the context of the electricity market transition described above, this section describes relevant elements of the existing transmission framework.

2.2.1 Existing transmission access regime

Currently, generators have a right to negotiate a connection to the transmission network, but no right to be dispatched. Since a generator's revenue from the wholesale market is currently determined by how much it is physically dispatched for, when it is not dispatched due to congestion, it receives no revenue. The service that a connecting generator is negotiating with a transmission network service provider (TNSP) for is power transfer capability at the connection point, not the ongoing use of the shared transmission network to be able to access the wholesale market.

2.2.2 Current dispatch and settlement arrangements

Once connected, a generator’s access to the shared network is determined dynamically through the dispatch process. Electricity flows on transmission lines consistent with Kirchhoff’s laws, which means that load and generation need to physically balance at each point in the transmission system. The NEM dispatch engine dispatches generators such that load and generation are balanced. It also dispatches generators in a manner that seeks to maximise the value of trade given the physical limitations of the power system.

The NEM dispatch engine is able to achieve this through determining the “locational marginal price” of generation in each location. The locational marginal price is calculated by working out the cost (as proxied by the offer prices of local generators) of supplying an additional megawatt of electricity at a particular transmission node.

Generators are dispatched by the NEM dispatch engine if they place offers at or below the locational marginal price of their transmission node. Generators with offers above the

6 Generators currently have a right to be connected, but no right to be dispatched.

locational marginal price are not dispatched. This is because these offers are above the marginal cost of supply and so would not result in the value of trade being maximised.

Generators are paid for the production of energy by market customers. This occurs through the central settlement process that is operated by AEMO. Under the current settlement arrangements, all load and generation are paid the regional reference price for the amount of electricity they consume or dispatch, respectively. The regional reference price is determined just like any other locational marginal price - it represents the cost of supplying an extra megawatt of demand (as determined by generator offer prices) at the regional reference node.

Generators that are not dispatched in a given settlement period do not generate electricity and so do not receive payment. That is, these generators do not receive access to the regional reference price. Thus, revenue is a direct function of physical dispatch.

2.2.3 Dispatch and settlement when the network is congested

As noted above, the NEM dispatch engine does take into account physical limitations that are otherwise known as 'constraints' and reflect, for example, the amount of electricity that can flow between points on the power system while preserving its integrity, safety and security.

If there are no constraints on the transmission network within a region, a generator’s locational marginal price would be the same as the regional reference price. When there is no congestion, supplying one more unit at the regional reference node could come from the local generator if it has the lowest marginal offer. This means that the price at the regional reference node must be the same as the price at the generator's local node (if losses are disregarded).

However, when congestion arises, locational marginal prices diverge from the regional reference price to reflect the transmission constraints that are occurring at a particular time. For example, if there is a constraint on the network, it is expected that a more expensive generator will need to be dispatched in order to supply consumers. This will increase the regional reference price. The displacement that occurs will be at the expense of lower cost generators located behind a constraint.

2.2.4 Incentives created by the current framework

Under the current arrangements, generators are unlikely to underwrite transmission assets to alleviate constraints. If a generator does underwrite or contribute funds for the shared transmission network, it is unable to reliably capture the financial benefits associated with that investment. This is because an investment in the shared network would improve access for all generators, not just the generator which underwrote the investment.

As such, there are no incentives under the current framework for different generators to collectively fund shared network assets. This lack of incentive exists because access to the network is determined dynamically through dispatch, as discussed above. Generators are not guaranteed a return on any investment in shared transmission assets because they cannot guarantee that they will be dispatched, or receive priority, and so earn revenue through the wholesale spot market.

Consequently, as the current transmission framework does not create incentives for generators to invest in transmission infrastructure, planning transmission to alleviate constraints (or open up entire new regions to the transmission network) is undertaken through centralised processes. These are discussed in the following section.

2.2.5 Current approach to transmission planning and investment

The planning of transmission investment (over both the short-term and long-term), as well as the decision to invest in particular infrastructure, are conducted through separate but related processes. The transmission network is currently planned through a central process led by AEMO and TNSPs, whereas the decision to invest is made by TNSPs.

AEMO undertakes longer term strategic planning of the NEM transmission network through its Integrated System Plan (ISP).[7] The ISP aims to identify the least cost combination of transmission infrastructure and non-network (generation and demand side) solutions to meet the load-side reliability standard. In doing so, it considers system security and any emissions trajectory determined by policy-makers at an acceptable level of risk.

TNSPs undertake shorter term, more targeted planning and publish a transmission annual planning report (TAPR) with this information. The TAPR focuses more on the near-term and is driven by specific identified needs. Once a specific need has been identified, TNSPs undertake project specific planning to identify the network investment or non-network option that has the highest net economic benefit.[8] The Regulatory Investment Test for Transmission (RIT-T) is the cost-benefit analysis used by TNSPs to assess the option that best addresses the identified need, given forecast patterns of supply, demand, transmission costs and other relevant factors.

This option could be an investment in transmission infrastructure, or an operating expenditure contract for a non-network option (generation or demand side). A range of alternative options are considered and quantified and the preferred option is the one that maximises the net market benefits.

TNSPs are incentivised to meet jurisdictional reliability standards when undertaking operational and investment decisions. Under the NER, there is currently no direct link between the RIT-T and the subsequent investment or operational decision that the TNSP may make. However, in practice, the RIT-T is undertaken to justify the TNSP's investment and inclusion in the regulatory asset base. While a TNSP is not obliged to undertake an investment following a RIT-T being satisfied, a TNSP often makes the investment decision identified in the RIT-T as the preferred solution. As a long-term strategic plan, the ISP does not direct the TNSP's investment decisions, however, those decisions will be informed by the ISP.

7 The ISP replaces the National Transmission Network Development Plan (NTNDP) which AEMO produces in accordance with section 49(2) of the NEL and clause 5.20.2 of the NER.

8 Clause 5.16.1(b) of the NER.

As such, AEMO (through the ISP), TNSPs (through their TAPRs and RIT-T processes), as well as the AER (through its revenue determination and related processes), make assumptions regarding future generation location and quantity in order to determine the appropriate level of access required by current and prospective generators, attempting to balance the cost of transmission investment with the cost of congestion.

The level of transmission infrastructure also influences the level of congestion. The most efficient level of congestion is not zero: building out all congestion would be very costly; having lots of congestion means that more expensive generators will be dispatched over lower cost generators. There are concerns at the moment that transmission infrastructure is not being built fast enough to facilitate the right level of congestion. However, this also creates concerns for consumers, who currently pay for transmission infrastructure. Due to the current limited locational signals in the transmission frameworks, as well as the speed and scale of connections of new generation capacity, investors are planning to connect where the network has limited or no capacity for additional generation to be dispatched.

2.2.6 The Integrated System Plan (ISP)

The ISP is a cost-based engineering optimisation plan prepared by AEMO that forecasts the overall transmission system requirements for the NEM over the next 20 years. The ISP modelling identifies target investment portfolios that can minimise total resource costs, support consumer value and provide system access to the least-cost supply resources over the 20-year planning horizon to facilitate the smooth transition of Australia's evolving power system.[9] In doing this, the ISP identifies an optimal development path for the power system that includes transmission investment, non-network solutions (generation, storage and demand response) and REZs.

The ISP considers development of REZs in the future that are optimised with necessary transmission developments, identifying indicative timing and staging that will best coordinate REZ developments with identified transmission developments to reduce overall costs.[10]

AEMO considers that an efficiently located REZ can be identified by considering a range of factors, which include:[11]

- the quality of its renewable resources (wind or sun, for example)
- the cost of developing or augmenting transmission connections to transport the renewable generation produced in the REZ to consumers
- the proximity to load, and the network losses incurred to transport generated electricity to load centres
- the critical physical must-have requirements to enable the connection of new resources, particularly inverter-based equipment, and ensure continued power system security.

The 2018 ISP identified a number of highly valued REZs across the NEM with good access to existing transmission capacity. AEMO noted that to connect renewable projects beyond the

9 AEMO, 2018 Integrated System Plan, p. 3.

10 AEMO, 2018 Integrated System Plan, p. 6.

11 AEMO, 2019 Planning and Forecasting Consultation Paper (February 2019) p. 42.

current transmission capacity, further action would be required (for example, increasing thermal capacity, system strength, and developing robust control schemes).[12]

2.3 Current transmission services

There are a number of costs in relation to the development of a REZ, including:

- building new, or upgrading existing, shared transmission network
- building new connection assets to facilitate the connection
- establishing the generator's facility.

Further below, we consider the nature of the transmission network and connection costs as they relate to the existing regulatory framework. There is a relationship between the assets and the type of transmission service being provided, and as a consequence, who pays for the service.

There are four categories of transmission services under the current regulatory framework:

1. prescribed transmission services
2. negotiated transmission services
3. large DCA services
4. non-regulated transmission services

We consider each of these transmission services, as they relate to the connection framework, below.

2.3.1 Prescribed transmission services

Prescribed transmission services are broadly those services provided by a TNSP in relation to the shared transmission network. The costs of providing prescribed transmission services are recovered from transmission network users through transmission use of system (TUOS) charges. The revenue that a TNSP can recover for these services is set out in chapter 6A of the national electricity rules (NER) and regulated by the Australian Energy Regulator (AER) pursuant to the transmission determinations made for each TNSP that provides these services.[13]

The regulatory asset base for a transmission system is the value of those assets used by the TNSP to provide prescribed transmission services. [14] Therefore, the value of any assets that provide prescribed transmission services form part of the regulatory asset base of the TNSP and are recovered from consumers through TUOS charges.[15]

12 Ibid, p. 42.

13 A transmission determination consists of a revenue determination for the TNSP in respect of the provision of prescribed transmission services, as well as a determination that specifies the pricing methodology that applies to the TNSP.

14 See clause 6A.6.1(a) of the NER.

15 See rule 6A.22 of the NER.

2.3.2 Negotiated transmission services

Chapter 5 of the NER specifies certain services in relation to the connection framework that are negotiated transmission services provided by a TNSP. There is no economic regulation of the revenue that a TNSP can earn for the provision of negotiated transmission services under chapter 6A of the NER. However, schedule 5.11 of the NER sets out negotiating principles that apply to negotiations between a TNSP and a connection applicant for negotiated transmission services. The terms and conditions, including price, of the provision of these services are negotiated between the TNSP and the party who wishes to receive these services on the basis of the negotiating principles. The value of any assets that provide negotiated transmission services do not form part of the regulatory asset base of the TNSP and therefore, are not recovered from consumers.

2.3.3 Large DCA services

Chapter 5 of the NER specifies certain services in relation to large dedicated connection assets that are subject to access, but are not economically regulated. These services can be provided by the TNSP, or by any third party. The person providing these services is called a dedicated connection asset service provider (DCASP). The DCASP is required to have an access policy to provide large DCA services to third parties.[16] If a TNSP provides such services, the value of any assets do not form part of the regulatory asset base of the TNSP and therefore, are not recovered from consumers.

2.3.4 Non-regulated transmission services

Chapter 5 of the NER specifies certain services in relation to the connection framework that are non-regulated and therefore, can be provided by the TNSP (or any third party) on a contestable basis. For example, these services could be the construction, operation or maintenance of a dedicated connection asset.[17] There is no access or economic regulation of these services under the NER. If a TNSP provides such services, the value of any assets do not form part of the regulatory asset base of the TNSP and therefore, are not recovered from consumers.

2.3.5 Connection assets

Under the existing connection framework, connecting parties are directly responsible for the payment of costs associated with any new apparatus, equipment, plant and buildings, or upgrades to existing apparatus, equipment, plant and buildings, to enable their connection to the transmission network and to meet their performance standards.

Under the NER, the transmission system assets required for connection of a generator to the transmission network can be broadly classified under two categories:

- identified user shared assets

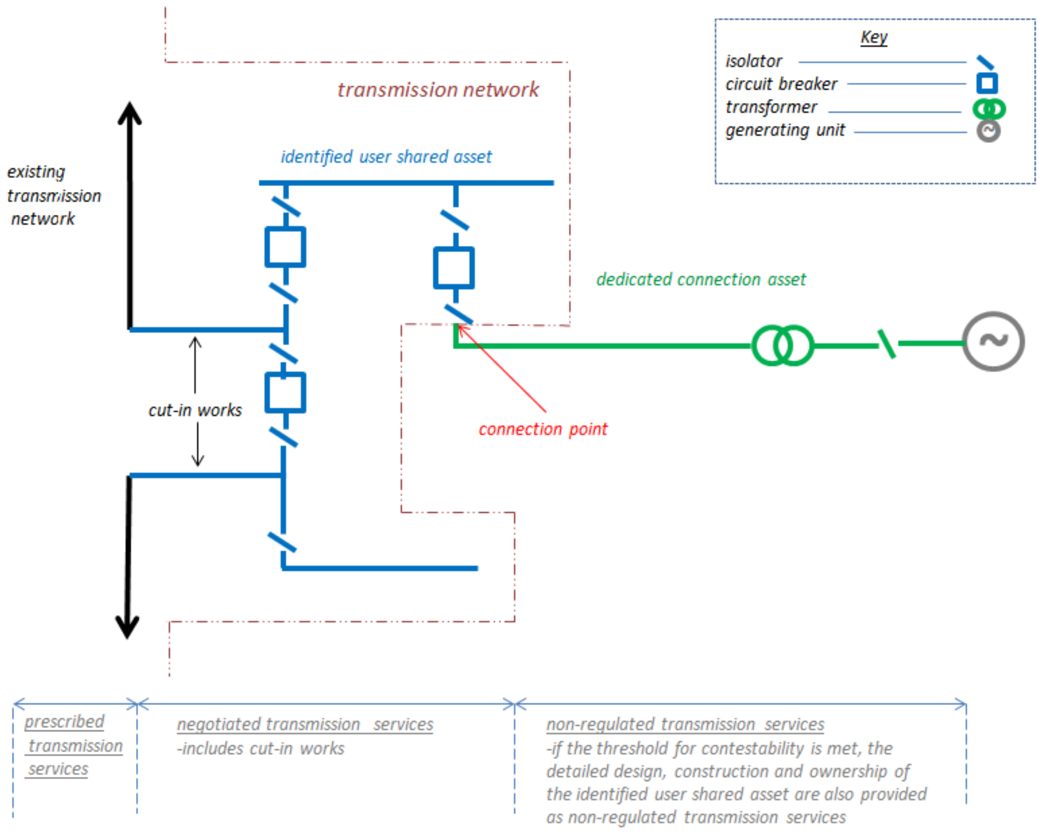
16 The access policy is established in accordance with the requirements of clause 5.2A.8 of the NER.

17 That is not a "large dedicated connection asset".

- dedicated connection assets[18]

The figure below shows the distinction between these categories of assets. Following, we consider these two categories in further detail, including the classification of services relating to the provision of these assets.

Figure 2.1: Transmission system assets



Source: AEMC, Transmission connection and planning arrangements rule, Final determination, 23 May 2018.

Identified user shared assets

The identified user shared assets (IUSA) broadly describe the collection of components that are used to connect a generator to the shared transmission network and which, once commissioned, form part of the shared transmission network (for example, parts of a substation or switching station).[19]

If the capital cost of all the components that make up an IUSA are reasonably expected by the TNSP to be $10 million or less, then the TNSP must undertake the detailed design,

18 For the declared transmission system (i.e. in Victoria), assets providing connection services are "connection assets" and "dedicated connection assets" are not applicable. For other transmission systems, there are "dedicated connection assets" and "network connection assets". "Network connection assets" are those components of a transmission system which are used to provide connection services between Network Service Providers

19 AEMC, Transmission connection and planning arrangements, Rule determination, 23 May 2017, p. iii.

construction and ownership of the IUSA as a negotiated transmission service.[20] However, if the capital cost is reasonably expected to exceed $10 million, then certain aspects of the IUSA are contestable.[21]

The value of the components forming part of the IUSA that are used to provide negotiated transmission services is not included in the regulatory asset base of the TNSP as they do not provide prescribed transmission services, and therefore, are not funded by consumers.

Dedication connection assets

Dedicated connection assets (DCAs) describe the collection of components that are used to connect a connecting party to the shared transmission network and which, once commissioned, are able to be isolated from electricity flows on the transmission network (for example, a power line that connects part of a substation to a generating system).[22] All development aspects of a DCA, including design, construction, maintenance and ownership, are contestable.[23]

The value of the components forming part of the DCA are provided as a non-regulated service and therefore, are not included in the regulatory asset base of the TNSP as they do not provide prescribed transmission services. Therefore, these costs are not funded by consumers.

Any party can register to be a dedicated connection asset service provider (DCASP) and construct, own and operate these assets - for example, a generator, a private company or a government.

A DCASP must classify its dedicated connection asset as a "small" or "large" dedicated connection asset in accordance with chapter 2 of the NER.[24] For large dedicated connection assets, the services provided are large DCA services. A DCASP that provides large DCA services must have an access policy in relation to the large DCA.[25] The requirements for an access policy are set out in clause 5.2A.8 of the NER.

Ongoing costs

Apart from the costs of connection, there are no ongoing charges that a generator pays to the TNSP for access to the transmission network. Because the costs of connection relate only to the cost of apparatus, equipment, plant and buildings required to connect a generator to the transmission network, the price that generators face does not reflect locational signals relating to the shared network,[26] and generators do not receive any guaranteed level of access to the transmission network, and thereby, no guaranteed level of access to the spot market.

20 See clause 5.2A.4(b) of the NER.
21 See clause 5.2A.4.(c) of the NER.
22 AEMC, Transmission connection and planning arrangements, Rule determination, 23 May 2017, p.iii.
23 See clause 5.2A.4(a) of the NER.
24 See clause 5.2.7(a) of the NER.
25 See clause 5.2.7(c) of the NER.
26 Except to the extent the power system conditions at the location of the connection necessitate specific investment, for example, system strength connection works because the generator locates in an area of the power system with weak system strength.

2.3.6 Connecting party facilities

Any facilities that relate to the connecting party itself (e.g. the generating units or large smelter) are the responsibility of the connecting party and are not directly regulated by the NER. However, the equipment that makes up and connects to the power system must perform to certain levels of technical capability. This helps AEMO to maintain the power system in a secure and safe operating state and manage the risk of major supply disruptions.

The levels of performance for equipment connecting to the power system are set out in performance standards for each connection. When connecting to the transmission network, a generator negotiates with the TNSP within the boundaries of access standards to reach agreement on the appropriate performance standards for that particular connection.[27] Once agreed, these performance standards form part of the generator's connection agreement.[28]

Generator performance standards cover a range of technical capabilities for connecting generators' equipment, including reactive power capability, quality of electricity, response to frequency and voltage disturbances during and following contingency events, frequency control, protection systems, and monitoring and control systems.

The range of access standards, as well as the process that applies to the negotiation, are set out in chapter 5 of the NER.[29]

2.4 Work programs considering REZs

There are a number of parties considering the implementation of renewable energy zones. We discuss some of these work programs below.

Finkel Review

The Finkel Review sought to address the challenge of coordinating transmission network planning and renewable generation investment through the development of REZs. It was envisaged that REZs would facilitate the connection of new renewable generators to the transmission network in a scale- and cost effective manner.

Energy Security Board

Recommendation 11 of the Energy Security Board’s *Integrated System Plan: Action Plan* states:

That the ESB examine the possibility of a Fund to extend transmission assets to connect to Renewable Energy Zones with the cost of this transmission progressively recovered from consumers if and when utilisation increases. The required size of the finance, the source of funds, and how funds should be recovered and managed should be part of the examination.

Clean Energy Finance Corporation

27 AEMO advises on "AEMO advisory matters" which are specified access standards.

28 See clause 5.3.4A(i) of the NER.

29 The technical access standards are contained in Schedules 5.1, 5.2, 5.3 and 5.3a of Chapter 5 of the NER and the negotiating framework is set out in Part B of the NER, and more particularly rule 5.3 and clause 5.3.4A.

The Clean Energy Finance Corporation is currently considering how REZs can be implemented. In particular, the CEFC is exploring the business case or commercial feasibility of a number of specified REZs and considering the challenges and opportunities associated with investing in REZs, as well as establishing potential financing and ownership strategies for REZs. The AEMC has been working closely with the CEFC, and has fed the CEFC's insights into this discussion paper where relevant.

ARENA

The Australian Renewable Energy Agency (ARENA) was created in 2012 to support improvements in the competitiveness of renewable energy and related technologies, as well as increase the supply of renewable energy in Australia. By providing grant funding to projects, ARENA accelerates the commercialisation of emerging technologies and supports the innovation chain from research to pre-commercial deployment in the renewable energy sector.[30] ARENA is also considering the implementation and potential funding arrangements for REZs. The AEMC is working closely with ARENA on this project.

AEMO

In its 2018 ISP, AEMO identified 32 candidate REZs. On 23 August 2019, AEMO held a webinar to discuss candidate REZs for the 2019/2020 ISP and to explain how REZs will be used within the 2019/2020 ISP modelling.[31]

For the purposes of the ISP, AEMO defines REZs as follows:[32]

REZs are areas in the NEM where clusters of large-scale renewable energy can be developed to promote economies of scale in high-resource areas and capture geographic and technological diversity in renewable resources.

The regulatory framework for any REZs that will be identified through the ISP will be progressed as part of the work under way to make the ISP actionable,[33] and will be implemented as prescribed transmission services paid for by consumers.[34] For example, the REZ in Western Victoria that was identified in the inaugural ISP can be used as an example of this type of REZ. The assessment of the Western Victorian Renewable Integration is currently being progressed through a RIT-T process undertaken by AEMO.

AEMC

This discussion paper builds on the work already undertaken by the AEMC on REZs through the directions paper published in June and in the final report of the inaugural COGATI review published in December 2018. This paper presents ideas that would require changes to the

30 ARENA website available from https://arena.gov.au/about/investment-priorities/

31 AEMO, 2019-20 Integrated System Plan: Candidate Renewable Energy Zones webinar slides (13 August 2019).

32 AEMO, 2019 Planning and Forecasting Consultation Paper (February 2019) p. 42.

33 The Consultation paper for this process was published in May 2019 and is available at http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/ESB%20-%20Converting%20the%20ISP%20into%20Action%20-%2020190517.pdf

34 Except for the generator's direct connection costs and facility costs, which it will remain responsible for, even for REZs identified and progressed through the ISP.

existing regulatory framework in order to facilitate REZs. These would work in conjunction with identification and implementation of the renewable energy zones through the ISP.

As the discussion above highlights, multiple parties are considering how to implement REZs in order to support the transition to a renewable energy future. The AEMC is working closely with these parties to make sure the various reforms under way are coordinated. The AEMC's contribution to the current work program on REZs is to identify ways to facilitate REZs that is coordinated with this other work underway.

3 COORDINATION OF GENERATION AND TRANSMISSION FOR REZS

3.1 Defining REZs and the issues to be addressed

The concept of a 'renewable energy zone' is not defined in the existing regulatory framework, and it has been used by different parties to describe different ideas. Often people have a different concept of what a REZ may be to them, depending on what they want to use a REZ for, what their role in the energy sector is, how they wish it to be financed, and the level of control they want over the REZ.

Therefore, a REZ may mean different infrastructure and arrangements to different parties. Therefore, this will mean that there are different ways of achieving a REZ under the current framework and different ways of facilitating REZs.

This chapter seeks to clarify the different ways in which a REZ can be characterised and the various issues that arise under those different characterisations. In doing so, this chapter aims to draw a correlation between:

- a particular type of REZ, and
- the issues that are relevant to that type of REZ, including the relevant service classification.

3.2 Characterising two types of REZ

In the AEMC's directions paper published in June,[35] we characterised REZs as a way of enhancing coordination between generators in order to achieve efficiencies of scale and scope with regard to procuring and using connection assets. This characterisation was in the context of the access proposal set out in the directions paper, which aims to resolve the coordination of generation and transmission investment.

However, based on stakeholder feedback, we understand that not all stakeholders see REZs this way. For example, in submissions to the June directions paper, a number of stakeholders considered the broader idea of a REZ incorporating augmentations to the shared network.[36]

Energy Networks Australia considered that a range of development options for REZs should be considered, and noted that the options need not be mutually exclusive, which reflects that REZ development will not be a "one-size-fits-all" matter.[37]

Stanwell acknowledged the role REZs can play in facilitating renewable energy integration and lowering system costs for consumers as the system transforms, but stated that it is not clear how they fit into the access reform framework currently under consideration.[38] Stanwell

35 The directions paper is available on the AEMC's website https://www.aemc.gov.au/sites/default/files/2019-06/COGATI%20-%20directions%20paper%20-%20for%20publication_0.PDF

36 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, directions paper submissions: Origin, p. 2; CEC, p. 4; ENA, p. 27.

37 ENA, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 9.

38 Stanwell, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 15.

stated that the benefits identified appear to relate to connections and planning rather than access and settlement, and appear applicable only to radial or lightly meshed areas of the network.[39]

3.2.1 Two different types of REZs

We consider there are two broad ways to characterise REZs:

1. **Type A REZ:** as a cluster of generators connected to the shared transmission network via a (large) dedicated connection asset. For a type A REZ, the transmission investment associated with the REZ are connection assets. These connection assets are paid for by the connecting party (or a party on their behalf) and so are not paid for by consumers via TUOS charges.
1. **Type B REZ:** as a cluster of generators within an approximate geographic boundary that are connected within the shared transmission network. For a type B REZ, the transmission investment associated with the REZ is shared transmission network (and connection assets for each generator). For the shared transmission network infrastructure, these will be considered prescribed transmission services and so paid for by consumers via TUOS charges (where a RIT-T has been satisfied).

In addition, there could also be "greenfield" and "brownfield" REZs:

- Greenfield examples include:
  - For a type A REZ - where there are is a brand new cluster of generators that want to locate in the same region and so share connection assets.
  - For a type B REZ - where there is no transmission infrastructure at the moment, but it is a particularly sunny location and so the transmission network is built out to that location.
- Brownfield examples include:
  - For a type A REZ - where there is an existing substation to connect a generator, and some new generators want to connect to that substation in order to have a more efficient connection.
  - For a type B REZ - where there is existing transmission infrastructure, but the network is relatively weak, and so to connect new generators into that location the existing network needs to be upgraded and reinforced.

These distinctions are important because how these different types of REZs can currently be facilitated under the regulatory framework, and the issues that arise, are not equally applicable for each type of REZ. In addition, there is varied complexity to developing arrangements for type A and type B REZs. Therefore, the solutions that each type of REZ can deliver, and how each type of REZ can be facilitated, will be different.

For a type A REZ, the issue is mostly one of coordination between *generation* investments. This is because the REZ only includes connection assets, which are either provided by the TNSP as a negotiated transmission service or non-regulated transmission service, or by a

39 Ibid.

third party as a contestable service, and are wholly funded by the connecting party or parties.[40]

On the other hand, for a type B REZ, the issue involves coordination between *generation* and *transmission* investment.[41] This is because the REZ includes infrastructure for the shared transmission network, which remains the responsibility of the TNSP. In most cases, investment in the shared transmission network is provided by the TNSP as a prescribed transmission service. Unless the proposed investment meets an exemption,[42] the TNSP must carry out a RIT-T in order to include the value of the investment in its regulatory asset base to be recovered from consumers through TUOS charges. However, if a RIT-T is not satisfied, there remains an opportunity for other parties, including generators, to fund such investments on a negotiated or non-regulated basis.

Breaking down the concept of REZs in this way is therefore helpful to work out the different issues and how these can be progressed. For example, AEMO's work on REZs for the purpose of the ISP defines REZs as 'areas in the NEM where clusters of large-scale renewable energy can be developed to promote economies of scale in high-resource areas and capture geographic and technological diversity in renewable resources'.[43] The image below, taken from AEMO's 2018 ISP, indicates that these REZs are therefore a type B REZ - and in most cases, a brownfield variant of a type B REZ.

The ISP does not define REZs in relation to the services and assets defined by the regulatory framework. Instead, the ISP identifies REZs as a cluster of generation in an approximate geographic boundary that may involve investment in the shared transmission network, in addition to an individual generator's connection assets.

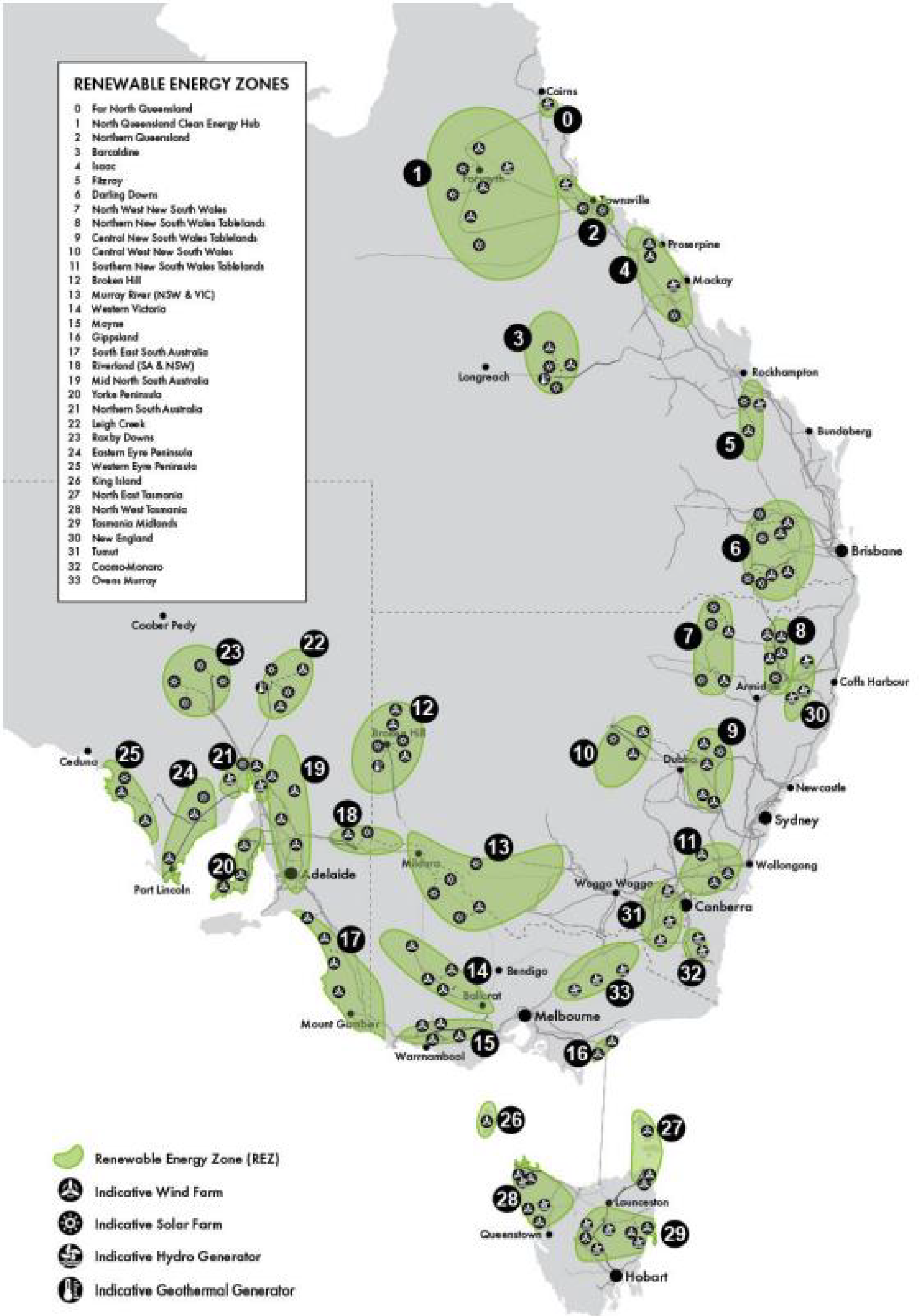
40 The National Electricity Amendment (Transmission connection and planning arrangements) Rule 2017 clarified that all services provided for dedicated connection assets, including design, construction, ownership, operation and maintenance, are non-regulated transmission services and can be provided by any party on commercial terms. Certain aspects of the services provided for the IUSA can also be contestable.

41 However, for a type B REZ, there can also be coordination between generators to the extent the generators may wish to coordinate or jointly fund aspects of their IUSA and connection assets in addition to the shared network augmentations required for the REZ.

42 See clause 5.16.3 of the NER.

43 AEMO, 2019 Planning and Forecasting Consultation Paper (February 2019) p. 42.

Figure 3.1: Integrated System Plan REZs



Source: AEMO, 2018 Integrated System Plan, p. 50.

3.2.2 There is not a one-size-fits-all approach

The Commission agrees that there is not likely to be a "one-size-fits-all" approach for the development of REZs. A particular REZ could be developed as either a type A or type B REZ, or a brownfield or greenfield REZ, depending on a number of factors. These could include:

- the location of the REZ in relation to existing transmission infrastructure
- the capacity of the REZ
- the number of parties connecting to the REZ
- the technical configuration of the REZ.

REZs that relate to radial parts of the network are likely to be less complex to facilitate. The complexity of facilitating a REZ increases where there is integration with the shared network, particularly where that becomes looped or more integrated into the network. In these instances, it is much harder to determine what is "REZ" versus "some other type of transmission infrastructure". Broadly, this is because the shared network is the responsibility of the TNSP, whereas connection assets are the responsibility of the connecting party and can be provided by the TNSP as a negotiated service, or by any third party as a contestable service under contract.

Even if a REZ is only in a radial or lightly meshed part of the network, this may still require augmentations or reinforcements to assets that form part of the shared network. Once the assets required for a REZ involve the shared network, even if only in a lightly meshed part of the network, different issues arise than for REZs that only involve connection assets.

QUESTION 1: TYPES OF REZS

Do stakeholders agree with the characterisation of these two types of REZ?

Are there any other ways to characterise REZs?

3.3 Summary of the issues relating to REZs

In the context of facilitating REZs, there are three key issues:

1. **Incentives to coordinate generation infrastructure:** Generators do not want to or are unable to coordinate connections in order to share the costs of connection assets because competitive tensions and commercial challenges act as a disincentive to do so.
2. **Incentives to coordinate transmission and generation infrastructure:** Generators face a free-rider issue and are unable to coordinate amongst themselves. A generator’s revenue is determined by dispatch, but generators do not want to fund (either individually or collectively) investment in shared network assets (deep augmentation) to improve dispatch given the free-rider problem and risk of not being dispatched, despite the investment. This has two components:
   a. There is no incentive for generators to fund shared network assets because of the free-rider problem. Under the current access framework, there is nothing to stop a

subsequent generator connecting beside it and effectively constraining off that first generator, undermining its ability to earn revenue from the wholesale market and so its business case. Throughout this paper, we refer to this as the "**free-rider problem**".

   b. The generator remains subject to the risk of not being dispatched when there is congestion, despite making the investment, because its physical dispatch is determined by the dispatch engine which takes account of, among other things, the physical capacity of the whole transmission network. The dispatch of any particular generator can be influenced by the dispatch of all other generators on the network, and therefore, the outcome of a particular generator's dispatch cannot be isolated to a particular part of the network that it has invested in. Throughout this paper, we refer to this as the "**dispatch problem**".

3. **Incentives for efficient transmission infrastructure:** Consumers bear the cost and risk of transmission infrastructure that provides prescribed transmission services. However, the existing transmission framework is not set up to connect all generators such that there is no congestion as this would not be efficient. Therefore, as a consequence of this framework, some of the existing transmission infrastructure may not necessarily be located in areas generators want to locate. There are no incentives to undertake speculative investment in new transmission infrastructure to build out to new generation areas because the costs may not be recovered.

This paper considers these three issues in the context of developing REZs.

In particular, we consider the second issue is a significant barrier for the facilitation of type B REZs under the current regulatory framework. Together, the "free-rider problem" and "dispatch problem" remove incentives for generators to invest in the shared transmission network, which prevents the facilitation of type B REZs.

The sections below discuss these issues in further detail in the context of developing type A and type B REZs, respectively.

QUESTION 2: SCOPE OF ISSUES

Do stakeholders agree that these are the relevant issues for REZs? Are there any others?

Which issue(s) do stakeholders think REZs should address?

3.4 Type A REZ

3.4.1 Type A REZ and issue 1

The type A REZ is:

Type A REZ: as a cluster of generators connected to the shared transmission network via a (large) dedicated connection asset. For a type A REZ, the transmission investment associated with the REZ are connection assets. These connection assets are paid for by the connecting party (or a party on their behalf) and so are not paid for by consumers via TUOS charges.

The type A REZ relates to the first issue stated in section 3.3. That is:

- **Incentives to coordinate generation infrastructure:** Generators do not want to or are unable to coordinate connections in order to share the costs of connection assets because competitive tensions and commercial challenges act as a disincentive to do so.

3.4.2 How can this type of REZ be facilitated under the current framework?

This type of REZ can already be facilitated under the current regulatory framework:

Connection framework

- Generators can facilitate a connection using the identified user shared asset (IUSA) and dedicated connection asset (DCA) framework.
- All development aspects of a DCA, including design, construction, maintenance and ownership, are contestable. Therefore, the current framework does allow third parties (other than the Primary TNSP) to own, operate and construct DCAs. Since all development aspects of a DCA are contestable, any party can register as a dedicated asset service provider (DCASP) and construct, own and operate these assets. This could be a private individual, a generator, a firm looking to invest in "renewable energy zones" or a government.
- If the dedicated connection asset is deemed to be "large'" (i.e. where the total route length for any power lines forming part of the dedicated connection asset is 30 kilometres or longer)[44] then it is subject to a regime for third party access. This requires the DCASP to prepare, maintain and publish an access policy for its large DCA on its website to provide a framework for applicants to obtain access to large DCA services.[45]
- All aspects of an IUSA are either contestable or provided by the TNSP as a negotiated transmission service. The connecting party can construct these assets itself, but the ongoing operation and maintenance of these assets has to be provided by the TNSP.
- Therefore, the value of the components forming part of the DCA and IUSA will not be funded by consumers through TUOS charges, but instead, are funded by the parties seeking to connect to the network or construct a REZ.
- In addition, there are cost sharing arrangements in the NER. If a subsequent generator comes along and wishes to connect to these connections assets after they have been constructed, there are a number of principles and obligations for how costs associated with subsequent connections to those assets should be recovered.

SENE framework

- In addition, there is the existing scale efficient network extension (SENE) framework. This requires transmission businesses to undertake and publish, on request, specific locational studies to reveal to the market potential opportunities for efficiency gains from the coordinated connection of expected new generators in a particular area.

44 See the definition of "large dedicated connection asset" in Chapter 10 of the NER.

45 See clause 5.2A.8 of the NER.

- The study is designed to help potential investors make informed, commercial decisions to fund a SENE, having weighed the potential gains from coordinated, efficient generator connection arrangements against the potential costs of assets not being fully used. Decisions to fund, construct, operate and connect to a SENE would then be made by market participants and investors within the existing framework for connections in the NER.[46]

Information provision

In addition, there is information that is made available to parties through the regulatory process that would help generators coordinate:

- The AER has published its TAPR guideline, which aims to support the consistent provision of information by transmission businesses across the NEM.[47] The guidelines require TAPR data to include information on forecast investments at each connection point and the location and size of applicant generator connections. This information will help generators and large transmission customers make more informed connection decisions. It will also inform non-network businesses on where they can offer energy services to address limitations on the transmission network.[48]
- The ISP provides information on optimal REZ development areas, which are supported by existing transmission capacity and system strength. The ISP sets out information to prospective connecting parties about where a good location to connect is (i.e. favourable resources and spare network capacity).
- In addition, information provision is being considered through the *Transparency of new projects* rule change currently being assessed by the Commission.[49] The AEMC has published a draft determination that would improve the transparency of new generation projects in the NEM, including by allowing AEMO to provide certain information to developers to help with building grid scale resources, such as a generating system.
- The Commission considers the draft rule will improve the transparency of new projects and assist developers to access the information they need to develop grid-scale resources, regardless of their business model, thereby promoting efficient investment in electricity services. The draft rule increases visibility of new connections and may enable generators to better coordinate with each other in the short term. A final determination is due to be published on 24 October 2019.

Therefore, there are already arrangements in the current regulatory framework that facilitate type A REZs - for both brownfield and greenfield circumstances. Further, this approach does not necessarily require coordination of multiple generators at the same time, as subsequent connections (at a later time) can be accommodated in an IUSA, for example. However, the full scope of benefits under type A REZs, such as over-sizing of the IUSA and meeting

46 In its submission to the directions paper, TransGrid said that the AEMC should revisit the original scale efficient network extension (SENE) rule change request as a potential solution to this issue. See: TransGrid, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging,* p. 2.

47 AER, Transmission Annual Planning Report Guidelines (December 2018).

48 See the AER website: https://www.aer.gov.au/communication/aer-finalises-its-transmission-annual-planning-report-guideline

49 AEMC, Transparency of new projects rule, Draft determination, 1 August 2019, available from https://www.aemc.gov.au/sites/default/files/2019-07/ERC0257%20-%20Draft%20determination%20-%20for%20publication.pdf

generator's system strength obligations, are more likely to be fully realised if multiple generators coordinate to connect at the same time to share the costs and achieve economies of scope.

3.4.3 Regulatory issues for type A REZs

Even if the coordination of funding for a type A REZ between multiple generators is resolved, additional operational issues may arise. We understand that there may be emerging issues with undertaking such an approach, particularly where the connection arrangement involves multiple unrelated parties.

A DCA is defined, in part, as an asset that can be electrically isolated from the transmission network without affecting the provision of shared transmission services.[50] In practice, the result of this is that a DCA operates behind the connection point to the shared transmission network.[51] As a result, there is a single connection point, as defined in the NER, for the DCA (and all parties connected to it). This may not be desirable for some parties from an operational perspective given connection points form the basis of a number of important financial and operational interactions in the NEM.

Primarily:

- Generator performance standards are negotiated between a connecting generator and a network service provider at a connection point. Where there are multiple parties connecting to the DCA, this increases the complexity in negotiating, agreeing and modelling performance standards, which would also need to be updated for the connection point each time a new party connects to the DCA.
- Settlement of the spot market occurs at a connection point with a financially responsible market participant (FRMP) and therefore, settlement of multiple parties connected to the DCA would need to be contractually determined, rather than individually by AEMO through the spot market (in which case there may need to be an intermediary appointed for spot market settlement purposes).
- Loss factors are calculated at the connection point and therefore one MLF would apply for the combined generation energy portfolio at the DCA connection point.

However, even if these issues are resolved, any investment made within a type A REZ could still be undermined as a result of the access framework. That is, under the current access framework, there is nothing to stop a subsequent generator connecting beside the REZ and effectively constraining off that first generator or group of generators connected to the IUSA, thereby undermining their ability to earn revenue from the wholesale market (and business case).

In other words, even if a type A REZ is used, the "free-rider problem" and "dispatch problem" remain. Therefore, even if generator coordination for type A REZs is resolved, broader access reform is still required to make investments in type A REZs sustainable.

50 See limbs (c) in the definitions of "dedicated connection asset" and "identified user shared asset" in Chapter 10 of the NER.

51 See the definitions of "connection point" and "identified user shared asset" in Chapter 10 of the NER.

3.4.4 Non-regulatory issues for type A REZs

We have previously received feedback from industry that competitive tensions and commercial challenges (including misalignment between generators' project timings) act as a disincentive for generators to facilitate coordinated connections through these mechanisms.[52] Such matters include:

- **Incentives:** There are incentives around competitive and commercial tensions (e.g. we understand that PPAs typically penalise connecting parties per day their connection is delayed). This can have the effect that even if coordinating with another generator may save money, the penalties for having the connection delivered late may be too great to make this worthwhile. This was supported by stakeholders. For example, PIAC has previously noted that this is because generators are rivals in a competitive wholesale market and as a consequence, they are unwilling or unable to share details with respect to financing, forecasting and other commercially sensitive information.[53]
- **Costs:** The costs of certain connection assets may be prohibitive for a single generator to fund, particularly if a large DCA is required for the connection arrangement. However, this is more a reflection of the fundamental economics of such projects, rather than the particular access model being used. Nonetheless, the current framework does allow third parties (other than the TNSP) to own, operate and construct DCAs, and therefore, having contestability provides flexibility for funding arrangements. The DCASP must have an access policy for a large DCA under which parties can request access to services provided by the large DCA.

These issues are non-regulatory barriers that are unlikely to be effectively resolved through further changes to the regulatory framework. It appears to be generally accepted that competitive tensions and commercial challenges act as a disincentive for generators to facilitate coordinated connections. While these non-regulatory barriers may be impeding the practical use of these options in the current arrangements, they cannot be readily addressed directly by the regulatory framework given they are non-regulatory barriers.

QUESTION 3: TYPE A REZS

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?

52 AEMC, Coordination of generation and transmission investment, Final report, 21 December 2018, p. 59.

53 PIAC submission to the Draft determination for Transparency of new projects, p. 2.

3.5 Type B REZ

3.5.1 Type B REZ and issues 2 and 3

The type B REZ is:

Type B REZ: as a cluster of generators within an approximate geographic boundary that are connected within the shared transmission network. For a type B REZ, the transmission investment associated with the REZ is shared transmission network (and connection assets for each generator).

Under the current regulatory framework, there are challenges to implementing the shared network part of type B REZs. These challenges relate to the second and third issues stated in section 3.1.

That is:

- **Incentives to coordinate transmission and generation infrastructure:** Generators face a free-rider issue and are unable to coordinate amongst themselves. A generator's revenue is determined by dispatch, but generators do not want to fund (either individually or collectively) investment in shared network assets (deep augmentation) to improve dispatch given the free-rider problem and risk of not being dispatched, despite the investment. This has two components:
  - There is no incentive for generators to fund shared network assets because of the free-rider problem. Under the current access framework, there is nothing to stop a subsequent generator connecting beside it and effectively constraining off that first generator, undermining its ability to earn revenue from the wholesale market and so its business case (the free-rider problem).
  - The generator remains subject to the risk of not being dispatched when there is congestion, despite making the investment, because its physical dispatch is determined by the dispatch engine which takes account of, among other things, the physical capacity of the whole transmission network. The dispatch of any particular generator can be influenced by the dispatch of all other generators on the network, and therefore, the outcome of a particular generator's dispatch cannot be isolated to a particular part of the network that it has invested in(the dispatch problem).
- **Incentives for efficient transmission infrastructure:** Consumers bear the cost and risk of transmission infrastructure that provides prescribed transmission services. However, the existing transmission framework is not set up to connect all generators such that there is no congestion as this would not be efficient. Therefore, as a consequence of this framework, some of the existing transmission infrastructure may not necessarily be located in areas generators want to locate. There are no incentives to undertake speculative investment in new transmission infrastructure to build out to new generation areas because the costs may not be recovered.

Potential type B renewable energy zones will be identified through the ISP and may also arise through generator connection proposals. Arrangements for implementation of renewable energy zones will complement and work in conjunction with the ISP and any implementation arrangements for the ISP.

3.5.2 How can this type of REZ be facilitated under the current framework?

This type of REZ is theoretically possible under two ways in the current regulatory framework:

- the planning and investment process
- a funded augmentation.

Planning and investment process

Consumers bear the cost and risk of the majority of transmission infrastructure. That is, the value of all transmission infrastructure that provides prescribed transmission services is included in the TNSP's regulatory asset base and recovered from consumers through TUOS charges.

The current regulatory framework, and consequently the transmission network, was primarily designed to connect large centres of thermal and hydro generation to major demand centres some distance away. However, the fuel resources for solar and wind generation are not generally well correlated with these centres of thermal and hydro generation. As such, there is limited transmission infrastructure in these new generation areas – referred to as "renewable energy zones".[54]

As the existing transmission infrastructure is not necessarily located in those areas where generators are seeking to locate (i.e. where there are abundant renewable resources), generators may need substantial connection assets (i.e. large DCAs) in order to connect a generating unit to the existing network. While the current regulatory framework facilitates connections of this sort, it may not be the most efficient outcome to have multiple generators connecting, on an individual basis, in this way.

This is what the actioned ISP is intended to address. The ISP will identify and prioritise an optimised, least cost portfolio of integrated system investments to maintain the reliability and affordability of the energy system as it transitions to lower emissions and more distributed generation.

Funded augmentation

In addition, generators can currently fund construction of shared network assets under the funded augmentation regime.[55] Generators - or a coalition of generators - can fund a transmission expansion in order to gain the benefits of reduced congestion. There have been some funded augmentations to date, albeit mostly low value projects.

The NER currently require a TNSP (whenever construction of a funded augmentation is proposed to occur) to make a notice available to registered participants and AEMO about the funded augmentation. This notice must set out a detailed description of the proposed funded augmentation, and all relevant technical details. While the notice itself does not need to be published more widely, a summary of the notice needs to be published on AEMO's website.

54 These new zones do not necessarily need to be limited to "renewable" energy resources, although in practice they generally are, as this is the predominant fuel source of the emerging generation fleet.

55 See rule 5.18 of the NER.

It is the funded augmentation approach that currently raises the core issues: the "free-rider problem" and the "dispatch problem". Together, these two problems remove incentives for generators to invest in the shared transmission network, which prevents the facilitation of type B REZs in relation to funded augmentations.

3.5.3 Regulatory issues for type B REZ

The planning and investment process

In its submission, AGL recognised that a significant issue facing the industry is a lack of clear transmission planning for the energy transition. AGL states that while the ISP provides a long-term view on possible opportunities for the creation of REZs, a suitable regulatory mechanism (which incorporates the RIT-T) to encourage its development does not exist.[56] On the other hand, in its submission, TransGrid noted that it considers the effective actioning of the ISP including the prioritisation and facilitation of REZs will solve many of the issues raised by the AEMC.[57]

The ISP can go some way to resolving these issues through identification of potential REZs and the ESB's work to convert the ISP into action.[58]

Funded augmentation

While generators are able to fund the construction of shared network assets through a funded augmentation process, they do not have an incentive to do so given the current regulatory framework. That is, no individual generator has preferential access to a shared network asset, even if the generator underwrote the transmission asset's construction, because access is determined by the dispatch engine. Each individual generator would prefer for other generators to underwrite transmission investment, to avoid the cost of doing so, while enjoying the benefits that the transmission infrastructure provides to all generators.

As a result, generators are unlikely to underwrite shared transmission network investment to secure better access (sometimes referred to as "deep augmentation"). Were they to do so, other generators would also enjoy the benefits of improved access without having contributed to the cost of that investment (the free-rider problem). As a result, in practice, generators do not underwrite shared transmission network investment, and so transmission investment in the majority of the shared network continues to be justified through a RIT-T and directly recovered from consumers as a prescribed transmission service through TUOS charges.

Consequently, the 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.

56 AGL, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, pp. 5-6.

57 TransGrid, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 1.

58 The Consultation paper for this process was published in May 2019 and is available at http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/ESB%20-%20Converting%20the%20ISP%20into%20Action%20-%2020190517.pdf

The Commission's proposal for access reform set out in the June directions paper sought to address this issue directly. The approach to access reform set out in that paper would help remove the free-rider problem inherent in the current connection regime by giving generators a financial risk management tool (a "transmission hedge") in return for making a financial contribution that underpins and directly drives transmission investment. The Commission was of the view that this increased financial certainty should incentivise generators to bear a large portion of the costs of transmission infrastructure that are required as a result of their locational decisions.

However, as discussed in the COGATI discussion paper - proposed access reform model, the Commission has reconsidered its approach to access reform, based on stakeholder feedback to the directions paper. Under the revised approach, financial transmission rights would not directly inform transmission investment. Instead, and in contrast to our previous proposal, the amount of financial transmission rights available would be limited to the aggregate amount of transmission capacity (both committed and currently available) as determined by the TNSP.[59] Therefore, there would only be an indirect feedback loop between the auction outcomes for the financial transmission rights and the planning process carried out through the ISP and TAPRs.

Therefore, without this linkage, a generator's investment in the shared network to facilitate a REZ could still be undermined as a consequence of the free-rider problem and dispatch problem. That is, there remains a risk that:

- other generators can come along and connect near the new REZ and benefit from those network investments without having contributed to the cost (the free-rider problem)
- other generators can come along and connect near the new REZ and cause congestion that prevents the REZ generators from being dispatched and earning revenue (the dispatch problem).

As a result, there is an outstanding issue to resolve in terms of facilitating investment in shared network infrastructure for new generation, which, principally, is needed in geographic areas where there are abundant renewable resources. The proposed model set out in chapter 4 seeks to address this issue directly.

3.5.4 Non-regulatory issues for type B REZ

Given that these types of REZs are facilitated through the regulatory framework, there are few non-regulatory issues (aside from those discussed above).

> **QUESTION 4: TYPE B REZS**
>
> Do stakeholders agree with this assessment of type B REZs?
>
> Are there any other barriers to facilitating a type B REZ?

59 Rather than being determined directly by market through their hedge purchase decisions, as previously proposed.

4 PROPOSED MODEL FOR REZ DEVELOPMENT

4.1 Introduction

The Commission has previously considered a number of ideas for facilitating the implementation of REZs. A number of these were explored in the 2018 COGATI final report, as well as the June directions paper.

This chapter presents a preferred solution for developing REZs. We have also considered a number of other potential models for facilitating REZs, which are set out in detail in Appendix A to this paper. This model would work in conjunction and complementary to the ISP and identification and implementation of renewable energy zones through that process.

The five models are:

1. Long-term hedges to fund transmission assets (preferred model)
2. Open season approach to connections
3. Speculative investment by TNSPs
4. Shared risk model (PIAC model)
5. Transmission bond model

Many of these models are not mutually exclusive and indeed, certain aspects from across the five concepts could be used to form one particular solution.

As the analysis in previous chapters, and the rest of this chapter demonstrates, there are already intended solutions in the current framework to address the first issue (efficient generator coordination) and to facilitate type A REZs. The main issues with type A REZs are non-regulatory.

Therefore, the remaining regulatory barriers arise under issues 2 (efficient generator and transmission coordination) and 3 (efficient transmission) and the facilitation of type B REZs.

The preferred model presented in this chapter would be the most effective at facilitating a type B REZ and addresses the second and third issues.

The following table provides a summary of all five models mapped against the type of REZ and issues that the concept relates to.

Table 4.1: **Models mapped against REZ type and issues**

MODEL	ISSUE ADDRESSING	REZ TYPE
Long-term hedges to fund transmission assets	2 - efficient generator and transmission coordination 3 - efficient transmission	B
Open season approach to connections	1 - efficient generator coordination	A
Speculative investment by TNSPs	3 - efficient transmission	B

MODEL	ISSUE ADDRESSING	REZ TYPE
Risk sharing model	1 - efficient generator coordination 3 - efficient transmission	A and B
Transmission bond model	1 - efficient generator coordination 3 - efficient transmission	B

4.2 Proposed model: Long-term hedges to fund transmission assets

4.2.1 Overview of model

This model focuses on the idea of generators making a financial contribution to some of the costs of transmission investment in the shared network required for a new REZ, and in return, receiving some guarantee about its financial return for making that investment. This concept therefore relates to a type B REZ that includes the investment of infrastructure that forms part of the shared network.

As discussed in previous chapters, there are two key problems that arises when REZs include shared network infrastructure: the free-rider problem and dispatch problem. That is, generators do not have an incentive to invest in shared network infrastructure because others can subsequently benefit from that investment without having contributed to the cost, or can cause congestion that prevents the first generator(s) from being dispatched. This concept seeks to mitigate those problems. It does so, primarily, by allowing a generator to purchase a long-term hedge that provides a form of firmer access to the regional reference price (RRP) through a financial payment in return for the investment made in the shared network needed for the REZ.

Although this model involves a consideration of the use of long-term hedges to incentivise investment in shared network assets for REZs, arguably, this approach could be extended to other investments in the transmission network other than REZs. However, it might be practical to test the mechanism with certain defined REZs first, before considering applying the mechanism to non-REZ transmission investment as well. We welcome stakeholders' views on this.

In its submission to the directions paper, the ENA suggested an approach for integrating the purchase of transmission hedges with the ISP and the transmission planning process. The ENA characterised this approach as an ability for generators to purchase long-term hedges to provide an additional source of revenue to be used to partially fund new investment and to reduce the TUOS charges consumers would otherwise face.[60] In this way, the arrangement would use the proceeds from the sale of transmission hedges as a supplementary form of transmission financing, used to reduce consumers' TUOS payments, but would not form a financial consideration on which the planning process would rely on.[61]

60 Ibid, p. 26.

The ENA's suggested approach involves the following steps:[62]

- the ISP would inform priorities for investment in the shared transmission network that would take account of (expected) generation developments and draw on a range of information sources as to the nature and extent of existing network congestion, including locational marginal price signals and, potentially, transmission hedge information
- TNSPs would conduct their RIT-T evaluations on each relevant transmission investment
- in parallel to the RIT-T process, the relevant TNSP would conduct a separate process to determine generator interest in acquiring long-term hedges in relation to the additional transmission capacity associated with the new investment
    - generators (and other parties) could be invited to make some form of down payment or bid for the subsequent right to secure long-term transmission hedges across the additional capacity, once it was built
    - such bids or down payments would be refundable if the relevant transmission capacity was not built, whereas, if the transmission investment did ultimately pass the RIT-T and proceed, those down payments would establish a first right to acquire the relevant long-term transmission hedges, in competition (through auction) with others that had also made down payments (with the down payment being used as a credit for any sum subsequently offered)
    - generators (or other parties) that bought such first rights to participate in a transmission hedges auction would be permitted to trade those rights prior to the auction
- the receipt of such down payments or bids would not drive the RIT-T evaluation, but their existence would reveal generators' preparedness to fund transmission investment in return for firmer access to the RRP (preferably over the long-term) and would therefore allow greater confidence that the investment would not be a "road to nowhere"
- where it satisfies the RIT-T, the investment would proceed as part of the regulated shared network, with the proceeds of the auction being used to offset the TUOS charges consumers face.

4.2.2 Assessment of model

We consider that there is merit in considering a model like this further to be available for renewable energy zone development, despite the challenges. Of the five models considered in this paper for the development of REZs, it is the only one that addresses issue 2 to create an incentive for generators to invest in REZs that involve more than just their connection assets.

The ENA considers one of the benefits of this approach is that it does not require generator contributions as a pre-condition for the investment to proceed, but instead, allows the potential value of achieving firm future access to be realised through the sale of hedges and

61 Ibid, p. 27.

62 Ibid, pp. 25-27.

used to offset the investment costs faced by consumers, where market participants deem that value to exist.

However, the ENA recognises the following challenges in this approach:[63]

- the incentives for parties to commit funds ahead of time will depend on their expectations of the value of the future transmission hedges, which will depend on the expected scale of the transmission investment
- detailed allocation rules would need to be developed to recognise issues such as loop flows.

We agree that these are challenges with this model, and consider these, and other challenges, further below.

The Commission considers there is value in having a process that allows generators to indicate their willingness to commit to a REZ.

A similar process to that proposed by the ENA could be used by TNSPs to gain expressions of interest (EOI) from generators for REZs. For example, a TSNP may have a number of connection enquiries in relation to a geographic area that has not yet been formally specified as a REZ. The TNSP could use this EOI process to gauge interest for transmission investment in that area.

Below we consider a number of the design elements of this model.

The expression of interest

The EOI process to identify generator interest could take a number of different forms, however elements of this process are likely to be similar the current SENE framework. There would likely be (at least) two stages of commitment. First, to commit to the investigation of the potential REZ, and second, to commit to connecting to, and funding, the REZ (discussed below as the financial commitment).

In order to demonstrate commitment to the investigation phase, generators would pay an upfront payment to cover the TSNP's estimated costs for investigating the location, size, configuration and cost of the REZ. Like the current connection process, interested generators would need to provide certain information to the TNSP to enable it to undertake this preliminary design and costing study. Once sufficient details were known, generators would be required to commit to the REZ to progress its detailed design and construction.

The financial commitment

An essential feature of this model is a requirement for generators to demonstrate their commitment to the proposed REZ through a financial payment, or "deposit". If the investment did not proceed, then the generators could receive their deposit back.

The financial commitment, or deposit, from the generators would need to be sufficiently large in order to be an effective mechanism for demonstrating genuine commitment to the proposed REZ, as scoped in the EOI phase. If the amount is insignificant, then generators

63 Ibid, p. 27.

may place deposits in many locations as a way of securing future access for at least one REZ, but without having a genuine intention to locate in that particular REZ. As a result, the amount needs to be sufficiently large so that generators are not incentivised to put deposits in for many possible REZs, but not so large as to be prohibitive. In this regard, we envisage that the deposit could be as much as 50% of the cost of the generator's share of the proposed REZ.

Cost recovery for the REZ

Under the ENA's model, there is a requirement for the investment to pass a RIT-T in order to proceed. It therefore seems implicit in this model that the REZ is provided, at least in part, as a prescribed transmission service. If the REZ was provided as an entirely negotiated (or non-regulated) transmission service, there would be no need to conduct a RIT-T. That is, if there is sufficient generator interest to cover the entire cost of the REZ, it could be built as a negotiated transmission service, without the need for a RIT-T.

However, if generator interest covered less than 100 per cent of the cost, the residual cost would either need to be taken on as a risk by the TNSPs, or paid for by consumers as a prescribed transmission service, where it could be justified under a RIT-T.

However, one of the inherent problems with transmission infrastructure investment is that it is "lumpy". There are scale efficiencies that are achieved by building in certain sizes. As a consequence, it is not likely that the committed generator interest would neatly align with the required size for the REZ. As a simplistic example, the committed generation may equal 500MW of capacity. However, the transmission infrastructure required for the REZ configuration may only be able to serve, for example, 450MW or 600MW. In the latter case, there is "spare" capacity provided by the investment for which there is no committed generation. In the former case, some generators would miss out on connecting to the REZ or could not receive the amount of capacity desired for their project.

Using the example above, the committed generation might cover 80 per cent of the cost of the 600MW investment, and this would be paid for by generators as a negotiated transmission service. The remaining 20 per cent of the cost of the REZ could either be:

- funded by a third party (e.g. government or funding agency)
- taken on by the TNSP (and potentially recovered from subsequent connections) or
- recovered from consumers as a prescribed transmission service where it could be justified under a RIT-T.

The current RIT-T framework, which requires RIT–T proponents to consider all credible options, promotes competitive neutrality, which promotes selecting the most efficient investment.[64] In addition, the RIT–T further promotes investment efficiency by imposing transparency and accountability on major transmission investment decisions. This contributes to the national electricity objective to the extent that other efficiency incentives under the regulatory regime are imperfect, or relatedly, to the extent that the economic interests of the RIT–T proponent differ from what maximises the net economic benefit across the market.[65]

64 AER, Application Guidelines, Regulatory investment test for transmission (December 2018) p. 10.

Under the current RIT-T application guidelines, set by the AER, RIT-T proponents must exclude externalities from their RIT-T assessments such that they are not included in either the costs or market benefits of a credible option and are therefore not included in the determination of net economic benefit. This includes external project funding received from another market participant (i.e. a registered participant or a consumer, producer or transporter of electricity).[66] For example, the guidelines state that funds that move between participants count as a wealth transfer and should not affect the calculation of the final net economic benefit under the RIT-T.[67] This means that if the project does not pass the RIT-T, then it is not deemed to be efficient, regardless of the capital contribution of the generators.

Therefore, in order to value this spare, unfunded capacity, the AER's application guidelines for the RIT-T process would need to be changed to modify the restrictions about capital contributions from market participants to either:

- remove or modify the market impact component
- remove or modify the wealth transfer restriction for generators.

Long-term transmission hedge

In return for the financial commitment, the generator would have the right to participate in an auction to purchase long-term transmission hedges. The generator would be required to pay the remaining cost of the investment once it proceeds (that is, the cost of its portion of the investment less the deposit already paid).

Firmness

Determining the quantity, or firmness, of the long-term hedge is a key challenge under this approach. Given the meshed nature of the transmission network, it is not possible to proportionately allocate a specified amount of capacity from a specified transmission asset to any particular generator. Therefore, the nature of the hedge is necessarily an approximation of the investment contribution.

Duration

The hedge would need to be close to the same length as the generator's investment, or if not, sufficiently long to be commensurate with the cost of the investment made by the generator. These hedges would be differentiated from the financial transmission rights sold under the access reform model (as discussed in the COGATI discussion paper) because the generators who invested in the REZ would need sufficient revenue certainty in return for the investment made, rather than having to compete with non-REZ generators in that auction for quarterly products three years in advance.[68]

Pricing

The hedge price would need to provide the generator with sufficient firmness to provide the generator with access to the RRP. This is because the hedge needs to hedge the difference

65 Ibid.

66 AER, Application Guidelines, Regulatory investment test for transmission (December 2018) pg. 6 and pp. 60-61.

67 Ibid, pg. 61.

68 AEMC, Coordination of generation and transmission investment discussion paper - access reform, section 6.1.

between the generator's local price and the regional reference price. However, the hedge should also not degrade the access of other generators who have also purchased hedges and so would need to be priced as such.

The hedge price would only need to be calculated each time a REZ investment is being considered, and therefore, it could be done manually by the TNSP for each REZ project. TNSPs would be responsible for calculating the hedge prices. The method for deriving the price of the long-term hedge would result in an overall price payable by the generator. The price would be paid over the course of the hedge period in instalments (which could align with the instalments of connection charges payable under the term of the generator's connection agreement).

The pricing methodology would be available for generators to use independently, albeit informally, to help in forming a business case for a hedge purchase for future REZ developments, which could also be a mechanism for generators and other parties to scrutinise the inputs in the model.

The table below summaries this model as it relates to the type of REZ and issues to be addressed.

Figure 4.1: **Summary of model 1**

Issue	Type A REZ	Type B REZ
Issue 1: Incentives to coordinate generator infrastructure	✗	✗
Issue 2: Incentives to coordinate transmission and generation infrastructure	✗	✓
Issue 3: Incentives for efficient transmission infrastructure	✗	✓

Source: AEMC

4.2.3 Conclusions of assessment

We consider this is the only model that addresses issue 2 - the incentives to coordinate transmission and generation infrastructure.

That is, if generators make an investment in assets for the shared network under the current framework, there remains the risk that:

- other generators can come along and connect near the new REZ and benefit from those network investments without having contributed to the cost (the free-rider problem)

- other generators can come along and connect near the new REZ and cause congestion that prevents the REZ generators from being dispatched and earning revenue (the dispatch problem).

This model seeks to address these two problems directly by providing generators with greater certainty about their financial return for the investment.

4.3 Conclusions on all models

In this paper, we have presented five models for improving the facilitation of REZs. This chapter has presented the preferred model and the other four models are discussed in Appendix A.

The various models reflect a range of incremental improvements that could be made to the transmission framework to help facilitate REZs. However, the preferred model – long-term hedges funding transmission assets – is the one that seeks to address issue 2.

As discussed in chapter 3, type A REZs can already be facilitated under the existing regulatory framework. For example, by connecting to the existing transmission network via an IUSA and a DCA. The remaining incentives around competitive and commercial tensions are non-regulatory problems that cannot be directly resolved through further changes to the regulatory framework.

Therefore, the addition of the preferred model to the current regulatory framework for type B REZs could address both types of REZs.

QUESTION 5: STAKEHOLDERS' VIEWS ON MODELS

What are stakeholders' views on the five models presented in this paper for REZs? In particular, do stakeholders think the preferred model (described above) should be pursued further?

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

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
CEFC	Clean Energy Finance Corporation
Commission	See AEMC
COAG	Council of Australian Governments
COGATI	Coordination of generation and transmission investment
DCA	Dedicated connection asset
ENA	Energy Networks Australia
ISP	Integrated System Plan
IUSA	Identified user shared asset
FTR	Financial transmission rights
MCE	Ministerial Council on Energy
NER	National Electricity Rules
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National electricity objective
PIAC	Public Interest Advocacy Centre
REZ	Renewable energy zone
RIT-T	Regulatory investment test for transmission
SENE	Scale efficient network extension
SCO	Senior Committee of Officials
TAPR	Transmission annual planning report
TNSP	Transmission Network Service Provider

A OTHER MODELS FOR DEVELOPING RENEWABLE ENERGY ZONES

In chapter 4, we recommended a preferred model for developing renewable energy zones (REZs). This appendix sets out four other models that the Commission has considered.

A.1 Model 2: Open season approach

A.1.1 Overview of model

This model involves a clustering or group consideration of connections to facilitate the coordination of generator connections based on what delivers the most efficient outcome. This concept relates to issue 1. That is, generators do not want to coordinate connections in order to share the costs of IUSAs or DCAs because competitive tensions and commercial challenges act as a disincentive to do so.

Under this model, rather than individual connection applications being approved on a sequential basis, the TNSP would establish a time window or "season", during which connection applications would be accepted, but not processed. At the end of the period, the TNSP would then assess all applications received up to that point as a group, planning the system and providing connection offers on a jointly optimised basis. Groups of generators could alternatively be clustered based on their geographic location, rather than through a connection season. To reap the benefits of the clustering approach, the season must be sufficiently long so that an appropriate number of connection requests accumulate, but not so long as to unduly delay connection applications.

A clustering approach requires the incumbent TNSP to assess the transmission augmentations needed to connect generation projects and coordinate these based on what is most efficient. The main benefits of a clustering approach appear to be that the risk of not being selected by the TNSP to connect as part of a cluster, and presumably be charged lower connection costs than they would be subject to if they were to connect separately, would incentivise proponents to:

- offer the most efficient solutions, including locating close to other potential connection proponents
- work constructively with the TNSP
- share information and work constructively with other project proponents.

It is important to clarify that a clustering approach does not have to mean that a generator is refused the ability to negotiate access to the transmission network altogether because the TNSP determined that the proposed connection was not part of the group of connection projects that would deliver the most efficient augmentation outcome. The clustering approach just means that the TNSP would not connect the generator as part of a cluster, but would negotiate it outside the cluster, as is the current process (at presumably a higher connection cost).

A.1.2 Assessment of model

There may be merit in this model as it would incentivise and facilitate collaboration between relevant parties. However, there are drawbacks, including that the proposed 'season' for connections may prevent otherwise efficient generation connections proceeding, or inappropriately delay such connections.

In addition, under this model, generators continue to have little incentive to fund assets for the shared network given the inherent nature of the transmission access regime (i.e. both the free-rider problem and the dispatch problem). Therefore, in practice, this option would more likely apply to type A REZs only in order to coordinate the costs of IUSAs and DCAs only (without further reform to address the incentive to fund shared network assets). The preferred model discussed in chapter 4 seeks to address those problems directly.

In submissions to the directions paper, a number of stakeholders raised concerns with this approach. The Clean Energy Council (CEC) considers that grid connection has been recognised as the biggest issue for CEC members given it is leading to increased costs and time for connecting generators and moving to an open season approach would only further increase the connection time for new generators.[69] The CEC states that this is clearly not an arrangement that supports the energy transition as it would slow down the ability for new lower cost generation to enter the market to meet reliability concerns and put downward pressure on wholesale prices.[70] In addition, the CEC considers that this proposal appears to target transmission-connected generators so could have unintended consequences for distribution-connected generators.[71]

Similarly, Delta Electricity considers it is unclear how an 'open season' under could work in practice given high levels of uncertainty around whether any or all proposals would progress to investment.[72] Likewise, AGL does not support the open season approach, on the basis that this model would not address the significant timing disconnect that currently exists and may in fact increase in the connection time for new generators.[73]

On the other hand, there was more support for this model from TNSPs. ENA and AusNet Services expressly supported consideration of the open season process.[74]

Whilewe recognise the possible benefits of this approach, on balance it does not recommend it as an exclusive approach to facilitating REZs. While this model could be workable in a more mature connection environment, it is unlikely to be feasible during the current transition. This is primarily because of concerns that the seasons will inappropriately delay connections. It would also impose significant uncertainty on connecting parties in relation to network

69 Clean Energy Council, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 4.

70 Ibid.

71 Ibid.

72 Delta Electricity, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 3.

73 AGL, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, pp. 5-6.

74 Australian Energy Market Commission, *Coordination of generation and transmission investment implementation - access and charging*, directions paper submissions: ENA, p. 9; AusNet Services, p. 3.

connection. To work effectively, the seasons may have to be sufficiently long to allow for prospective generators to accumulate. However, in doing so, there is the risk that generation connections are not processed in a timely fashion. Overall, many stakeholders were concerned about this delay.

The table below summaries this model as it relates to the type of REZ and issues to be addressed.

Figure A.1: **Summary of model 2**

Issue	Type A REZ	Type B REZ
Issue 1: Incentives to coordinate generator infrastructure	✓	✗
Issue 2: Incentives to coordinate transmission and generation infrastructure	✗	✗
Issue 3: Incentives for efficient transmission infrastructure	✗	✗

Source: AEMC

A.2 Model 3: Speculative investment by TNSP

A.2.1 Overview of model

Another potential model involves TNSPs making speculative investments in new transmission infrastructure to facilitate a REZ for prospective generators. That is, shareholders of TNSPs would bear some of the risks associated with transmission investment to a REZ.

This model is a direct response to issue 3. That is, TNSPs have limited incentive to undertake speculative investment to facilitate the construction of transmission infrastructure for a REZ. Existing transmission infrastructure is not necessarily located in the areas where there are abundant renewable resources, but generators rely on AEMO and TNSPs determining where and when transmission infrastructure, other than their connection assets, is built.

Under current arrangements, TNSPs could make speculative investments (that is, investments which have not been provided for in the allowed revenue as part of the AER's revenue determination, or otherwise provided for through, for example, the contingent project process). However, in doing so, they would be exposed to risks and costs, including:

- If treated as providing negotiated transmission services, the assets would not be rolled into the regulatory asset base and so the costs would not be recovered from consumers through TUOS charges. If the costs are also not recovered from connecting generators, the TNSP would not recover its costs.

- If treated as providing prescribed transmission services, under certain circumstances, incurred capital expenditure that does not meet the capital expenditure criteria may be excluded from the regulatory asset base and so not recovered from consumers through TUOS charges.[75] The capital expenditure criteria relate to the whether the expenditure is efficient, would have been incurred by a prudent operator, and based on realistic expectation of demand and cost inputs.[76]
- Even if the investment is treated as a prescribed transmission service and the value is rolled into the regulatory asset base at the next regulatory control period, financing costs associated with the speculative investment would not be recovered by the TNSP, consistent with the capital expenditure sharing scheme.[77]

The effect of these mechanisms is to reduce the incentives for TNSPs to undertake speculative investments.

Changes to the framework could be made similar to the mechanism for speculative investment set out in the National Gas Rules (NGR), for example.[78] This would provide stronger incentives for TNSPs to undertake speculative investments in shared transmission. Under such a mechanism, the TNSPs could undertake speculative investments and include this expenditure in a speculative capital expenditure account. This speculative expenditure is expenditure that does not conform to the regulator's assessment of what is appropriate at a given point in time, but that can subsequently be approved by the regulator due to changes in circumstances. If, as a result of the specified changes, the expenditure becomes approved by the regulator, the relevant portion of the speculative capital expenditure account (including a rate of return that is approved by the regulator) can be rolled into the asset base at the commencement of the next regulatory control period. This would then allow the capital cost to be recovered through TUOS charges in the future.

The intention of this approach is that:

- TNSPs would be incentivised to bear more of the risk associated with REZ development, by receiving a higher return on investments that are ultimately (with the benefit of hindsight) in the interest of consumers, while
- consumers would be protected from the risk of stranded assets because they do not pay for the asset if an investment is ultimately (with the benefit of hindsight) not in their interest.

A.2.2 Assessment of model

The Commission considers that making changes to allow alternative rates of return for speculative investments carried out by a TNSP is now largely unworkable as a result of the introduction of the *Statutes Amendment (National Energy Laws) (Binding Rate of Return Instrument) Act 2018*. The legislative amendments remove heads of power for the Commission to make rules regarding the determination of a rate of return. The amendments

75 Clause S6A.2.2A of the NER.

76 Clause 6A.6.7(c) of the NER.

77 Rule 6A.5A of the NER.

78 Rule 84 of the NGR.

implement a binding instrument that sets out a single approach to the calculation of rate of return parameters for all regulated electricity service providers, and which is developed through a single, industry-wide process every four years.[79]

Therefore, facilitating such a mechanism would require law changes. Despite the legal challenges, however, there remains a key policy challenge in determining the appropriate higher rate of return for the investing TNSP. In any case, we do not consider that the mechanism is in the long term interests of consumers.

Under the current regulatory framework, there are limited incentives on TNSPs to undertake speculative investment. This is appropriate for investments that provide prescribed transmission services given that the risk of any over-investment (e.g. speculative investment that turned out to be unnecessary) rests with consumers who pay for the transmission infrastructure built by TNSPs through TUOS charges. It is not appropriate for TNSPs to undertake speculative investment where consumers bear the risk of incorrect investment decisions. This is not in the long term interests of consumers.

However, a variation on this model could involve the creation of a mechanism that creates ways for the TNSP to receive better information about the commitment of prospective generation, and to use this "commitment" to inform decisions about future investment. Some of the other models discuss ways of facilitating commitment from prospective generators.

The table below summaries this model as it relates to the type of REZ and issues to be addressed.

Figure A.2: **Summary of model 3**

Issue	Type A REZ	Type B REZ
Issue 1: Incentives to coordinate generator infrastructure	✗	✗
Issue 2: Incentives to coordinate transmission and generation infrastructure	✗	✗
Issue 3: Incentives for efficient transmission infrastructure	✗	✓

Source: AEMC

79 AER, Rate of Return Instrument (December 2018).

A.3 Model 4: Risk-sharing model (PIAC model)

A.3.1 Overview of model

The Public Interest Advocacy Centre (PIAC) has developed a framework, which it presented to the COGATI technical working group in May 2019. This section has been informed by PIAC staff providing a more detailed description to AEMC staff to include in this REZ discussion paper.

The proposed model provides for how the cost and risk of investment in new and existing infrastructure for REZs could be shared between consumers, generators, TNSPs and other investors. While PIAC has presented one way of sharing the cost and risk of REZ investment, there could be other risk sharing models that achieve a similar outcome.

Core to the PIAC model is that the recovery of capital expenditure is apportioned between generators and consumers, rather than just consumers. The amount apportioned to generators is funded by a speculative generator. This apportioning could be determined by the regulator or by government, and be based on some combination of:

- the value of access to the REZ for connecting generators, compared to the costs and risks incurred with the same investments being made under the current access arrangements at the time
- the market benefits to consumers of the REZ being built, compared with the same investments being made under the current access arrangements at the time
- where the REZ is part of an interconnector or other transmission investment, the portion attributable to consumer or generator benefits. If there is a clear primary purpose for the investment, any portion of the investment with dual benefit could be attributed to that purpose
- policy objectives.

Summary of the model

Under PIAC's model:

- Feasible prospective REZs, including transmission network options, are identified through the existing ISP process by AEMO, or by industry or government.
- A detailed design stage, incorporating a RIT-T or equivalent process, determines the optimal attributes for a given REZ, and selects one or more network design options that is best suited to support efficient investment and market outcomes. This stage would include market testing with prospective generators, investigation of planning approvals, and estimation of capex for different network options. A variety of sources of information should be considered to minimise the risk associated with speculative investment.

A key attribute determined in the detailed design stage is a prescribed 'efficient' capacity level, expressed as the firm/maximum physical capacity of new generation supported by the REZ. This attribute will reflect a number of factors, including:

- the level and certainty of current generation market interest in and near the proposed REZ, and the current state of the generation investment market more broadly

- the potential future investor interest in and around the REZ, considering the nature of the energy resource, planning opportunities and constraints, government energy and planning policy, and anticipated energy market conditions.

The function of the efficient/nominal capacity level is described in the following section on risk and cost sharing.

During or before the design stage, direct recovery of capex up to the 'efficient' capacity is apportioned between generators and consumers.

The risk sharing basis for this apportioning is described in the following section on risk and cost sharing.

A contestable process, such as a tender or reverse auction, would be conducted to choose an investor to fund the speculative portion of the capital spend associated with the REZ. The successful bidder will be chosen on the basis of the lowest rate of return offered. This portion is ultimately recovered from connecting generators via connection charges. The remaining capex, and all opex, is rolled into the RAB of the incumbent TNSP and recovered from consumers via conventional TOUS charges.

The AER would approve all revenue up to the 'efficient' capacity, including the cap on generator connection charges, before the REZ is built.

The TNSP builds and operates the new and augmented transmission network assets required for the REZ. Assets may be built in stages to limit costs and finance.

New generators that connect to the REZ pay a connection charge to recover costs to the speculative investor. This can be paid at any time between when the REZ revenue is determined and the generator is connected. By avoiding some of the speculative rate of return, earlier payment of connection charges results in a lower connection cost for the generator.

For ease and feasibility of implementation, the model should use current arrangements as far as practicable. These include:

- the generator connection process and charge structure
- mechanisms to allocate TUOS charges to consumers
- regulatory processes and governance measures.

Cost and risk sharing

For the REZ to be developed, the risks and costs are shared between multiple parties based on the principles that beneficiaries should pay and risks should be allocated to those best placed to manage them. The costs allowed to be recovered for investment up to the prescribed 'efficient' capacity is regulated. Their recovery is apportioned between:

- **Generators:** This portion is funded by a speculative investor and recovered directly from connecting generators via connection charges, and
- **Consumers:** This portion is rolled into the RAB of the incumbent TNSP and recovered directly from consumers via conventional TOUS charges. If the generation and transmission investments that are enabled through the speculative investment prove to

be efficient and prudent, these costs will ultimately be passed through to consumers as well.

The revenue from this investment up to the prescribed 'efficient' capacity is shared between:

- **The incumbent TNSP:** This portion of the cost of investment would be recovered from consumers in a manner similar to how TNSPs currently recover shared network costs.
- **The speculative transmission investor:** This portion would be recovered from generators who would pay a connection charge to connect to the REZ. The connection charge would be proportional to the generator's capacity and how early they connected. That is, at any given point in time, the cost for generators to access prescribed capacity would be a fixed rate in terms of $/MVA. The rate paid by generators would increase with time according to a speculative rate of return escalation factor.

If a speculative transmission investor considers that interest in a REZ may be more than the prescribed 'efficient' capacity level determined, then the transmission investor may fund this additional capacity and negotiate with generators as unregulated revenue. They could seek higher returns for this portion to compensate for the additional risk of investing in capacity without guaranteed cost-recovery.

Value proposition

Under the PIAC model, generators are protected from the risk of REZ underutilisation and timing misalignment between different generation projects. In lieu of bearing these risks, generators pay a rate of return premium to TNSPs, who bear some of the timing risk. Generators are incentivised to reduce this risk by connecting, or at least paying to connect, earlier.

Speculative transmission investors voluntarily take on underutilisation risk for their portion of investment costs, and receive an uplift in their rate of return for doing so. The incumbent TNSP is protected from the risk of asset stranding as their costs are recovered from consumers under normal arrangements, but they are free to bid for the contestable speculative investment.

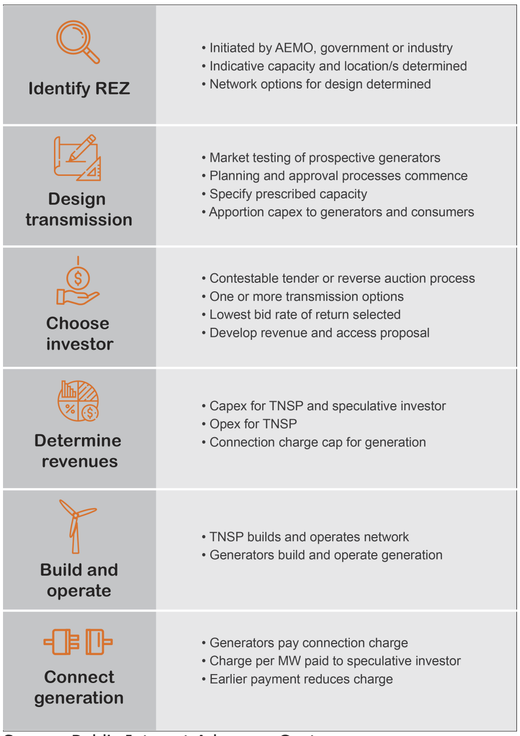
At the same time, the PIAC model reflects that consumers have little or no ability to manage the risk of underutilisation or asset stranding in REZs and are not direct beneficiaries of generator connection assets. The speculative investment represents value for consumers because it prevents inefficient transmission investment and a less competitive wholesale market from being fully socialised to consumers.

Consumer exposure to the risk of underutilisation is capped at a fixed, limited portion of the investment value. This limits their liability, relative to current arrangements, under the 'worst case' where utilisation is low. If the generation and transmission investments that are enabled though the speculative investment prove to be efficient and prudent, then consumers will benefit and these costs will effectively be passed through to them through the wholesale market.

Government has the option of taking on some underutilisation risk by underwriting some portion of the capex for prescribed capacity.

PIAC's model is summarised in the diagram below.

Figure A.3: PIAC risk sharing model



Source: Public Interest Advocacy Centre

A.3.2 Assessment of model

PIAC notes that the model it has developed helps drive efficient system-wide outcomes in a timely, cost-effective and equitable way, and also allows the option for governments to underwrite a portion of the investment cost to help reduce uncertainty.[80]

Although ENA supports consideration of flexible funding arrangements, they have a number of reservations regarding the PIAC model.[81] Of its members specifically, TransGrid does not support the PIAC model,[82] and AusNet Services considers there are significant barriers to the workability of the PIAC model.[83] In particular, the ENA notes that the model appears to set up a fundamental disconnect between the party bearing the risk (TNSP) and the parties who determine the extent of that risk (AEMO) and the compensation for bearing the risk (AER), which can be expected to lead to a very real risk of the investment not proceeding.[84]

80 PIAC, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, PIAC, p. 6.

81 ENA, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 9.

82 TransGrid, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 9.

83 AusNet Services, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 3.

AEMO welcomes further consideration of the model proposed by PIAC, but notes that it would be useful to define more clearly what types of assets would be subject to the proposed funding model (for instance a REZ could potentially refer to connection assets or shared transmission infrastructure).[85] AEMO also notes that further work is likely to be required to clarify how underutilisation risk would be managed under the PIAC model, since historically TNSPs have been unwilling to take on this type of risk.[86]

Likewise, the Clean Energy Council also sees merit in further considering a risk sharing arrangement for REZs as proposed by PIAC, but seeks clarification from the AEMC whether this risk sharing model would apply to shared network assets or only to connection assets.[87]

We understand that the model would apply to type B REZs (shared network assets), as type A REZs (connection assets only) are already fully funded by generators.

Overall, we agree with stakeholders' concerns about the drawbacks of this model. In particular, the second issue discussed in chapter 3 is not solved under this model. That is, wherever generators make an investment in assets for the shared network, there remains the risk that:

- other generators can come along and connect near the new REZ and benefit from those network upgrades without having contributed to the cost (the free-rider problem)
- other generators can come along and connect near the new REZ and constrain off the REZ generators (the dispatch problem).

AGL acknowledges this problem in its submission, noting this model has some challenges with determining how to prevent the REZ from being constrained and whether different levels of flexibility in REZ design/regulatory enforcement is necessary based on location.[88]

Under this model, a generator's investment in the REZ can ultimately be undermined by a subsequent generator connecting near the REZ, even if it is not part of the defined REZ. In doing so, the subsequent generator may be able to benefit from the REZ development because it is in electrical proximity to the REZ, and may do so without having contributed any of the costs for the REZ.

In addition, it would be particularly difficult to determine a connection cost based on the time a generator connects to the REZ given the portion of any generator's cost is based on its timing and nameplate rating, which is influenced by the relative contribution of future generators (also based on their timing and nameplate rating), but which is unknown.

84 ENA, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 29.

85 AEMO, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 4.

86 Ibid.

87 CEC, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 4.

88 AGL, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, pp. 5-6.

The preferred model set out in chapter 4 considers a potential option for shared funding of assets for the shared transmission network that attempts to mitigate the free-rider problem and risk of not being dispatched.

The table below summaries this model as it relates to the type of REZ and issues to be addressed.

Figure A.4: Summary of model 4

Issue	Type A REZ	Type B REZ
Issue 1: Incentives to coordinate generator infrastructure	✗	✓
Issue 2: Incentives to coordinate transmission and generation infrastructure	✗	✗
Issue 3: Incentives for efficient transmission infrastructure	✗	✓

Source: AEMC

A.4 Model 5: Transmission bond model

A.4.1 Overview of model

This model focuses on the introduction of a mechanism that allows generator proponents to enter into a contractual arrangement with a TNSP to demonstrate their commitment to a particular REZ, thereby minimising the risk of speculative investment for the TNSP (discussed in model 3 above).

Under this approach, generators would be committing to building new capacity at specific locations in the grid. This would allow TNSPs to approach the AER, with greater certainty about the benefits from new transmission investment. The contract would include terms penalising the generation proponent for not proceeding.

Engie proposed a "transmission bonds" model in its submission to the May 2018 discussion paper for COGATI.[89]

Key features of Engie's model include:

- potential REZs would be identified through, for example, the ISP or TNSP planning processes
- a TNSP would estimate costs for a potential transmission augmentation to a REZ

89 Engie, submission to the discussion paper, *Coordination of generation and transmission investment*, 18 May 2018, pp. 3-5

- the TNSP would issue transmission "bonds" of sufficient value to cover the estimated cost of the transmission augmentation - Engie's proposal notes that the bonds should be denominated as $/MW (notional capacity not firm capacity)
- prospective generators could purchase the bonds
- if sufficient bonds to cover the value of the transmission augmentation were sold, the augmentation would proceed. If the bondholder:
    - connects to the transmission augmentation, the value of the bond would be returned to it, and
    - does not connect, they would forfeit the value of the bond, which would be used to offset TUOS charges
- if insufficient bonds were sold to cover the cost of the augmentation, the project would not proceed and bond holders would get the value of the bonds returned to them
- generators which are not bondholders would be unable to connect to the augmentation for a set number of years (say, three)
    - this mechanism attempts to avoid a potential free-rider problem whereby an individual prospective generator would prefer to wait for other prospective generators to purchase bonds so that the transmission augmentation proceeds, while avoiding risks associated with purchasing bonds
    - were each individual generator to take this approach, no bonds would be sold and the augmentation would not proceed

A more fulsome description of Engie's model can be found in its submission, which is available on the AEMC's website.[90]

It is instructive to consider the nature of the "bond" product being bought, sold and owned. In effect, the instrument is a guarantee on the part of the bondholder that if the TNSP does X, the bondholder will do Y or pay a "penalty" of $Z. Precisely defining X and Y may be practically and legally challenging, but simplistically:

- X approximates "build transmission assets for a REZ"
- Y approximates "connect a generation asset (of certain size, characteristics, etc) to the aforementioned REZ"
- Z could be a partial cost of the transmission asset.

In return, by buying the instrument, the generator is, first, able to influence whether and where a transmission asset is built, and second, given privileged ability to connect to the REZ.

A.4.2 Assessment of model

This model has the benefit that customers will not bear the risk of speculative transmission development and stranded investments and that governments could choose to subsidise transmission investment by purchasing bonds. In addition, the mechanism does not depend

90 Engie's submission is available from https://www.aemc.gov.au/sites/default/files/2018-05/ENGIE.pdf

on generators, who are in competition with one another, coordinating their actions. Instead, the decision to secure bonds for a given investment is made by each generator individually.

Despite these benefits, the Commission previously considered that the model has some implementation challenges and is not appropriate. Principally, it reached this conclusion because the model appears to assume that investment in a fully (or highly) utilised transmission asset is economically efficient. That is, the model assumes that provided the transmission asset is used because there is a commensurate amount of generation connected to the transmission asset, then investment in the transmission asset is in the interest of consumers. However, this assumption does not appear to be correct. It is possible that a high cost transmission asset could be highly utilised but the total system cost to consumers would be inefficiently high. As the generators are not paying for the transmission augmentation itself (rather, only promising to pay for the transmission asset if they fail to connect), the cost of the transmission asset is still borne by consumers through TUOS charges once built.

Because the instrument being bought and sold is not being used to pay for the transmission asset (other than in the case that the bondholder fails to connect to the transmission asset) it is not possible to rely on the sale of bonds to determine whether a transmission investment is efficient. Therefore, the sale of transmission bonds could only inform a RIT-T, not replace it.

In addition, we consider it would be very difficult to define the prohibition of "not connecting to the augmentation". Given the meshed nature of the transmission network, the benefits of the augmentation may extend beyond an immediate asset (say, a given transmission line). Therefore, it may be possible for other parties to connect near the augmentation, and benefit from it, while still not connecting directly to it.

In its submission to the June directions paper, Mondo notes that the AEMC has previously decided not to support the transmission bonds idea first proposed by ENGIE and while it agrees with the AEMC's observations, it suggests that they may not be sufficient reasons for rejecting the proposal.[91]

In its submission, Tilt Renewables also urged the AEMC to reconsider the transmission bonds approach, whereby generation developers commit a smaller monetary amount to confirm their willingness to connect at a location before the NSP builds.[92]

The ENA also proposed a similar concept for REZs that includes the use of some form of down-payment so that generators (or other parties) can back their intentions by putting up financial commitments, some portion of which may then be refunded once those generators have connected to the developed REZ.[93] The ENA's suggestion is discussed in chapter 4 as part of the preferred model.

However, we consider that there are still considerable drawbacks with this model. The holder of the instrument would, in return for acquiring the instrument, be granted privileged

91 Mondo, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 9.

92 Tilt Renewables, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 3.

93 ENA, submission to the directions paper, *Coordination of generation and transmission investment implementation - access and charging*, p. 9.

connection rights to the REZ for a set period, while other generators who did not purchase a bond, would result in a time-limited denial of connection rights to non-instrument holders for that REZ for a number of years. This delay is needed to address the free-rider problem.

As discussed in other models above, this free-rider problem lies at the heart of why generator-funded transmission investment in the shared transmission network is practically implausible under the existing open access regime.

Under the existing regime, generators are provided insufficiently firm access rights to justify them making an investment in transmission augmentation, because the benefits of such investment can be enjoyed by other generators.

That is, wherever generators make an investment in assets for the shared network, there remains the risk that:

- other generators can come along and connect near the new REZ and benefit from those network upgrades without having contributed to the cost (the free-rider problem)
- other generators can come along and connect near the new REZ and constrain off the REZ generators (the dispatch problem).

In addition, given stakeholders' reservations about model 2 (the open season approach) causing inappropriate delay to connections, we are interested in stakeholders' views about whether a similar concern arises under this mechanism as well, or if there are alternative ways to mitigate this delay. It would be difficult to determine the appropriate length of the delay. While the proposed suggestion is three years, it seems unlikely that this would be a sufficiently long period to provide sufficient financial certainty for the generators' investments. If a generator makes a financial contribution that underpins transmission investment, it would expect some guarantee about its financial return for making that investment, and three years does not seem commensurate with the nature of transmission investment.

In order to address the connection delay issue, the prohibition on non-instrument holders connecting to the REZ could be removed from the model. By buying the instrument, the generator would still be able to influence whether a transmission asset is built, but this would not prevent the free-riding problem. However, given the importance of selling bonds to facilitate this model, the removal of this restriction would likely result in no bonds being sold, as each generator waits for others to build their augmentation.

However, 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 the ENA in its submission (discussed in chapter 4).[94] For example, the mechanism could provide an additional avenue by which prospective generators could signal their intention to connect in a manner which the TNSP and AER could treat as "committed" generation. In this way, certain aspects of this model could be combined with aspects of other models as an information tool to facilitate greater certainty in the development of future REZ infrastructure.

94 Ibid, pp. 25-27.

The table below summaries this model as it relates to the type of REZ and issues to be addressed.

Figure A.5: **Summary of model 5**

Issue	Type A REZ	Type B REZ
Issue 1: Incentives to coordinate generator infrastructure	✗	✓
Issue 2: Incentives to coordinate transmission and generation infrastructure	✗	✗
Issue 3: Incentives for efficient transmission infrastructure	✗	✓

Source: AEMC