REVIEW

Australian Energy Market Commission

DISCUSSION PAPER

Coordination of generation and transmission investment

13 April 2018

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Discussion paper

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

E: aemc@aemc.gov.au
T: (02) 8296 7800
F: (02) 8296 7899

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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.

Executive Summary

The COAG Energy Council has asked the Australian Energy Market Commission (AEMC or the Commission) to undertake biennial reporting on a set of drivers that could impact on future transmission and generation investment. This work has a focus on evaluating the transmission frameworks in respect of providing better co-ordination of investment between the transmission and generation sectors.

The Commission commenced stage 2 of this review in August 2017. This discussion paper presents the Commission's initial views on three key developments which may necessitate changes to the current transmission framework:

1. likely future congestion on transmission networks as more generators seek to connect to the grid in places where there is not substantial spare capacity
2. new types of generation capability – such as large-scale battery storage – connecting directly to the transmission network
3. more lower emissions generation such as wind and solar farms entering the market, which may need to locate in areas that are at the edges of the existing network, potentially in new renewable energy zones (REZs).

These developments were highlighted in stakeholder submissions to the AEMC’s earlier approach paper. Our preliminary analysis of the implications for the transmission framework of congestion, the treatment of storage and REZs are set out below. This paper provides an opportunity for stakeholders to give feedback on this analysis, ahead of a final report in mid-2018.

However, before considering these three issues, it is worth understanding the current transmission framework, which can be described broadly as having the following key features:

- Parties have a right to negotiate a connection to the transmission network, but no right to earn revenue in the wholesale market i.e. there is an open access framework for generators.
- Transmission network services providers (TNSPs) have to meet jurisdictionally-set reliability standards that reflect a trade-off between the cost of building and maintaining the networks and the value placed on reliability by customers, which are defined in terms of serving customer load.
- End-use consumers pay for costs incurred by the TNSPs in providing shared transmission services from which they benefit, including the investment and operational costs which are reflected in a transmission business’s revenue that is recovered from consumers (known as "transmission use of system charges," or "TUOS charges") and which is regulated by the Australian Energy Regulator (AER).
- Generators only pay for the costs of the services provided to them by the transmission business to facilitate their connection to the transmission network.
- The transmission businesses plan the network, which assists in identifying the solutions to network issues in a timely manner. The Australian Energy Market

Operator (AEMO), as national transmission planner, provides an independent, strategic view of the efficient development of the National Energy Market (NEM) transmission grid.

- Augmentation and replacement decisions relating to the network are subject to cost-benefit tests (regulatory investment tests) to assess whether the investment or replacement will create a net market benefit for consumers.

The transmission framework will be enhanced by new rules starting on 1 July 2018 to make it:

- cheaper for generators to connect – there will be more competition in building the transmission lines and substations that connect generators to the network
- faster for generators to connect – through a clearer and more transparent connections process.

Commission's preliminary views

1. Congestion in the NEM

The issue of congestion management in the NEM has been the subject of ongoing debate since the establishment of the NEM in 1998. As there are no firm access rights for generators in the NEM, there is no guarantee that they can export all of their output to the system at any given time. Since the start of the NEM, there have been twelve major reports and reviews dealing with various aspects of congestion management and generator access.

There is limited information available on current and recent patterns of congestion in the NEM or on expected congestion from the large number of potential connections in the pipeline. It is important to know the incidence and cost of congestion in order to estimate the scale of the problem. The scale of the problem will reveal what potential regulatory reforms, if any, are suitable to address any identified problems with the current framework. The Commission engaged Ernst & Young (EY) to assess patterns and costs of congestion in the NEM.

The EY work demonstrated that there are limited amounts of congestion in the NEM at the moment – and of that which does occur, it is largely between regions (that is, “inter-regionally”). There is limited congestion within regions to date.

However, there is over 45,000 MW of proposed new generation which has expressed interest in connecting across the NEM.[1] While all of this new generation may not eventuate, to the extent it does and depending on where it is located, there could potentially be significant congestion in the future.

The Commission is therefore interested in feedback on the analysis about the current state of congestion in the NEM, how this might change as the energy transformation occurs, and the potential ways in which this could be addressed. At the start of stage 2 of this review, the Commission identified a spectrum of options relevant to addressing congestion management. The first four are focussed around transferring some of the

1 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

risks anticipated with transmission network spend from consumers to generators in return for financial access, and includes optional firm access. The latter two options focus around options to better facilitate transmission planning outcomes in the NEM and include renewable energy zones, a key focus of this paper.

2. Treatment of storage

Some of the proposed new generation capability entering the market includes large-scale, utility storage. One notable example has already connected – Tesla's battery at Hornsdale Wind Farm – showing that the regulatory framework can facilitate the connection of storage.

The experience of a few storage connections that have occurred to date has revealed some potential areas of the regulatory framework for the coordination of generation and transmission investment that may need to be clarified or adjusted to better facilitate large-scale storage connections. Feedback on the existing regulatory framework typically involves asking questions about:

- whether or not storage devices should pay for use of the transmission network, as loads currently do, rather than only pay to connect to the transmission network, as generators currently do
- how hybrid facilities that combine storage with another generation source are treated for the purposes of registration under the NER.

This discussion paper sets out the current state of play in relation to these issues, and work currently underway. The solution to both of these questions with the current framework may be the same, for example, resolving the registration issue may also help resolve the question of whether or not transmission use of system charges should be paid. The Commission is interested in stakeholder views on these matters.

3. Renewable Energy Zones

The *Independent Review into the Future Security of the National Electricity Market: Blueprint or the Future* (Finkel Review) sought to address the challenge of coordinating transmission network planning and renewable generation investment, specifically focussing on the option of the development of REZs to facilitate the connection of new renewable generators to the transmission network. As noted above, in progressing to stage 2 of this review, the Commission identified a spectrum of options to coordinate generation and transmission investment in the NEM, however we are focussing on REZs in this discussion paper given the Finkel Review sought to progress consideration of this model.

As recommended by the Finkel Review, AEMO has commenced the development of the inaugural Integrated System Plan (ISP) that it states will deliver a strategic infrastructure development plan that can facilitate an orderly energy system transition under a range of scenarios, including REZs. AEMO defines REZs as "areas 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."[2]

2 AEMO, Integrated System Plan consultation paper, December 2017, p.29.

Key questions are what exactly is a REZ, who pays for the investment required to develop a one, and who bears the risk of the REZ not developing or operating as planned. Under some definitions of a REZ, they can easily be accommodated in the existing regulatory framework; while other REZ models would require potentially significant changes. This discussion paper sets out the Commission's initial views on how these zones could connect to the existing shared transmission network, and the implications of this for the existing regulatory framework. We welcome stakeholder views on this.

The central consideration in the potential development of REZs is who should bear the risks associated with these investments, in order to make sure that transmission investment is provided in a way that is consistent with the long-term interests of consumers. The existing regulatory frameworks establish protections for consumers from inefficient expenditure.

The paper also outlines initial feedback received on AEMO's ISP, which suggests that the current framework for the approval of transmission investment requires changes to accommodate a REZ model. Similar issues are being considered through the AER's review of the regulatory investment test application guidelines. The AEMC's work on this review, AEMO's work on the ISP and the AER's work on the regulatory investment test application guidelines are closely linked – and all three market bodies have established arrangements to work together on these issues.

Stakeholder consultation

The Commission invites comments from interested parties in response to this discussion paper by 18 May 2018. All submissions will be published on the Commission's website. We would also welcome meetings with stakeholders. Stakeholders wishing to meet with the AEMC should contact Therese Grace at 02 8296 7842 or therese.grace@aemc.gov.au.

Contents

1 Introduction

The COAG Energy Council has asked the AEMC to implement a biennial reporting regime on a set of drivers that could impact on future transmission and generation investment. This work will assist governments and industry participants to consider when future conditions might arise where net benefits would be derived from adopting a transmission framework, which would provide for better co-ordination of investment between the transmission and generation sectors.

The Commission commenced stage 2 of this review in August 2017 by publishing an approach paper. This discussion paper is the next iteration of our thinking, and presents further information to, and asks questions of, stakeholders about how coordination of generation and transmission investment in the NEM can be improved. Specifically, this paper:

- provides context as to how this work fits in with the Commission's overall work programme
- provides a detailed description of the current transmission framework in operation in the NEM
- examines potential drivers of change within the current transmission framework, specifically:
  - transmission planning and connection: the scale and potential cost of congestion in the NEM
  - transmission charging: the treatment of storage, such as batteries
- provides an analysis of REZs, specifically what are they, how they fit within the current framework, and what regulatory changes would be required to accommodate them, depending on how they are designed.

1.1 Terms of reference

The terms of reference for this reporting were received from the COAG Energy Council in February 2016.[3]

The terms of reference directs the AEMC to implement a biennial reporting regime on a set of drivers that could impact on future transmission and generation investment, under section 41 of the National Electricity Law (NEL).

The task, as outlined in the terms of reference, is a two-stage approach to the reporting of conditions that influence transmission and generation investment. The stages as outlined in the terms of reference are:

- Stage 1 - In the first stage, analysis is to be undertaken on a set of drivers that influence the co-ordination of transmission and generation investment. The aim of the first stage is to determine whether there is substantial change in a factor(s) such that it suggests that there is an environment of major transmission and generation investment and that this investment is uncertain in its technology or

3 The terms of reference are available from the AEMC website at http://www.aemc.gov.au/getattachment/97164a7b-09bf-49fb-9f2e-f6b996f5a96b/Terms-of-referen

location. If it is determined that such conditions are present, the reporting will progress to the second stage.

- Stage 2 - The second stage is to be a more in-depth assessment of whether the factors identified in Stage 1 have changed materially since the time of the *Optional firm access design and testing review* concluded in July 2015 to suggest that investment of an uncertain nature is likely to take place. The second stage would also have an assessment of whether the implementation of a model that would introduce more commercial drivers into transmission and generation development would meet the National Electricity Objective (NEO).

The drivers that were considered in stage 1 of the review are outlined in the terms of reference, and are:

- government policies and international agreements
- technological developments
- the establishment and penetration of new business models
- the level of distributed generation
- the level of variance in forecasts
- NEM rule and regulation changes.

The final stage 1 report provided the Commission's analysis on each of these drivers as well as other developments in wholesale and contract markets.[4] We have referred to updated developments, where relevant, throughout this report.

1.2 Findings from stage 1

Stage 1 of this review concluded in July 2017 and the Commission recommended that the review progress to stage 2. Three decision criteria were met in making this recommendation. The decision criteria are:

- the drivers of transmission and generation investment have significantly changed since July 2015
- there is expected to be large amounts of transmission and generation investment
- the expected future investment is uncertain in its location and technology.

The drivers of transmission and generation investment have changed significantly since the AEMC was issued with its terms of reference. At the time, we noted that there is increased uncertainty regarding government emissions reduction policy, and that this is having ramifications for investor confidence. This is still the case, although the intent of the National Energy Guarantee is to address this.

There is an observed trend of thermal generation exiting the market and significant entry of variable, renewable generation. The take-up of distributed energy resources is

4 The final stage 1 report is available from the AEMC website at http://www.aemc.gov.au/Markets-Reviews-Advice/Reporting-on-drivers-of-change-that-impacttransmi/Final-Stage-1-report/AEMC-Documents/Final-Stage-1-report.aspx

also expected to continue, with new business models entering the market seeking to maximise the benefits from these resources.

It is expected that there will be significant transmission and generation investment in the future, which is evidenced by the large number of potential connection applications being made to network businesses. We found that increased low emission generation will be needed to reduce the emissions intensity of the generation sector. Renewable generation is likely to potentially locate in areas that are at the edges of the existing network. Therefore, the shape of the transmission network may need to change in response, in order to reliably supply consumers.

The location and technology of this new investment is uncertain. This is due to a range of factors, which are all discussed in chapter 2 of this report.

1.3 Purpose of this paper

This discussion paper presents further information to, and asks questions of, stakeholders about how coordination of generation and transmission investment in the NEM can be improved.

It provides an opportunity for stakeholders to provide input to this review, ahead of the final report being published in mid-2018.

1.4 Consultation process

This paper will be open for stakeholder consultation. The Commission invites comments from interested parties in response to this discussion paper by 18 May 2018. All submissions will be published on the Commission's website subject to any claims of confidentiality.

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting project reference code "EPR0052".

We would also welcome meetings with stakeholders. Stakeholders wishing to meet with the AEMC should contact Therese Grace at 02 8296 7842 or therese.grace@aemc.gov.au.

1.5 Related work

This review forms part of a broader reliability work program being undertaken by the AEMC as discussed in this section. This section also discusses related Reliability Panel, Energy Security Board, AER and AEMO work programs.

1.5.1 Reliability Frameworks Review

In July 2017, the AEMC commenced a review into the reliability frameworks under section 45 of the NEL. Over the past 18 months, a series of events (such as the load shedding in South Australia and New South Wales in February 2017), as well as numerous policy debates have led to a greater focus on reliability in the NEM. At the same time, the NEM has been changing at a rapid pace on both the demand and the supply side. This review is considering the reliability frameworks in this context.

An issues paper was published in August 2017, followed by an interim report in December 2017. The interim report provided an update on the Commission's views to date to facilitate stakeholder consultation and feedback.

A directions paper for this review will be published shortly. The directions paper will provide the next iteration of the Commission's thinking on the key streams of work, including: forecasting, assessing the suitability of a day-ahead market in the NEM, developing a mechanism to facilitate demand response and assessing the need for a strategic reserve to enhance or replace the existing Reliability and Emergency Reserve Trader (RERT).[5]

1.5.2 Reliability Standard and Settings Review

The Reliability Panel's work supports the national electricity system, and is comprised of members who represent a range of participants in the NEM, including AEMO, generators, network businesses, consumers and large end users. The Panel's core functions relate to the safety, security and reliability of the national electricity system. The National Electricity Law sets out the key responsibilities of the Panel.[6]

The Panel’s work program is largely driven by specific requirements set out in the National Electricity Rules (NER). Generally, the focus of the Panel’s work is on determining standards and guidelines which form part of the framework for maintaining a secure and reliable power system.

Every four years, the Panel is required to review the reliability standard and reliability settings. The Panel's current *Reliability standard and settings review* is considering whether the reliability standard and settings remain suitable for the period 1 July 2020 to 30 June 2024 to guide efficient investment and operational decisions in the power system to meet consumer demand for energy, while protecting market participants from substantial risks that threaten the overall stability and integrity of the market.

On 21 November 2017, the Reliability Panel published a draft report that proposes to leave the reliability standard and settings unchanged for the period 1 July 2020 – 1 July 2024.

The Reliability Panel considers this appropriate as:

- The existing standard and settings are, in its view, still achieving their purpose and are likely to continue to do so out to 2023-24.
- Providing regulatory stability through no changes will benefit consumers and market participants, given the current impact of policy uncertainty on investor

5 AEMO has recently submitted two rule change requests to the Commission with regards to the RERT. The first rule change requests that the Commission reinstates the long-notice RERT as a short-term measure for the upcoming summer of 2018/19. The second asks the Commission to consider AEMO’s proposal for an enhanced RERT as a longer-term solution. The issue of strategic reserves will therefore no longer be considered through the Reliability Frameworks Review, but rather these rule changes will be progressed separately and form part of the Commission’s Reliability work program.

6 These include: to monitor, review and report on the safety, security and reliability of the national electricity system; and at the request of the AEMC, to provide advice in relation to the safety, security and reliability of the national electricity system.

confidence, the rapid technological change underway in the NEM, and the absence of sufficient evidence in support of a change to the price settings.

- Matters relevant to other components of the broader market and regulatory frameworks for reliability in the NEM are being considered through other proposals and reviews being progressed by the market bodies.

1.5.3 Integrated System Plan

Currently, under the NER, AEMO is required to publish a National Transmission Network Development Plan (NTNDP) by 31 December each year, the purpose of which is to provide an independent, strategic transmission planning assessment for the NEM, with a 20 year outlook. This serves as an input for TNSPs on transmission investment required for inclusion in their Annual Planning Reports. However, the final report of the Finkel Review recommended an alternative approach - the preparation of an integrated grid plan for the NEM. The purpose of the IGP is slightly different to the NTNDP and is to facilitate the efficient development and connection of REZs across the NEM.[7]

AEMO is currently preparing the inaugural Integrated System Plan (ISP), calling this an ISP, rather than an integrated grid plan, to reflect that over time, the ISP will by necessity consider a wide spectrum of interconnected infrastructure and energy developments including transmission, generation, gas pipelines, and distributed energy resources. The first ISP is scheduled to be published in June 2018.

AEMO intends for the first ISP in June 2018 to deliver a strategic infrastructure development plan, based on sound engineering and economics, which can facilitate an orderly energy system transition under a range of scenarios. According to AEMO, this first ISP will particularly consider:

- what makes a successful REZ and, if REZs are identified, how to develop them
- transmission development options.

As the ISP's purpose and scope encompass those which would normally be covered in AEMO's National Transmission Network Development Plan (NTNDP), the AER has permitted AEMO to defer the release of the 2017 NTNDP and integrate it into the ISP.[8]

1.5.4 AER Regulatory Investment Test Guideline Review

The AER is currently undertaking a large scale review of the application guidelines for the regulatory investment tests (RITs). The RITs are required to be performed under the NER and are cost-benefit analyses that network businesses must perform and consult on before making major investments or replacements in their networks.[9] The

7 *Independent Review into the Future Security of the NEM: Blueprint for the Future*, June 2017, p.9.

8 AER, Quarterly Compliance Report: National Electricity and Gas Laws, 1 October – 31 December 2017, p. 21.

9 Clause 5.6.5C of the NER provides that a TNSP must apply the RIT-T to all proposed transmission investments unless the investment falls under defined circumstances. Clause 5.17.3 of the NER provides that a RIT-D proponent must apply the RIT-D to a RIT-D project unless the project falls under defined circumstances.

application guidelines for RITs provide guidance on how to apply the RITs to potential investments that the NER states must be subject to these tests. When undertaking RITs, network businesses must give due consideration to all possible options before identifying the best way to meet the demands on their networks.[10]

The NEM currently has separate RITs for transmission and distribution networks – the 'RIT-T' and 'RIT-D'. Each RIT has its own application guidelines in order to guide network businesses on how to apply the RITs consistently and transparently.

On 20 February 2018, the AER published an issues paper to provide information on the RIT-T and RIT-D application guidelines. The issues paper provides an indication of the AER's initial views on the effectiveness and limitations of the current RIT guidelines. The AER's review of the RIT application guidelines will explore improvements that:

- the COAG Energy Council identified in its RIT–T review
- have arisen out of the replacement expenditure planning arrangements rule change[11]
- have been identified from ongoing applications of the RITs
- stakeholders identify.

The issues paper highlighted that a significant issue that will be considered is how the ISP, in particular REZs, relate to each other. The AER is seeking feedback from stakeholders on what additional guidance would be useful in the RIT-T guidelines with respect to the ISP.[12]

Draft guidelines will be released in May/June 2018.

1.5.5 National Energy Guarantee

On 24 November 2017, the COAG Energy Council agreed that the Energy Security Board should provide further advice on a National Energy Guarantee (the Guarantee). This is to be provided in April 2018, after broad consultation. The initial advice on the Guarantee broadly and conceptually set out changes needed to the NEM and its legislative framework such that the:

- reliability of the system is maintained
- emissions reductions required to meet Australia's international commitments are achieved
- above objectives are met at the lowest overall costs.

On 15 February 2018, an initial consultation paper was released by the Energy Security Board to facilitate public consultation on the high-level design of the proposed Guarantee. Subject to COAG Energy Council in-principal agreement to proceed with the detailed design of the Guarantee, further consultation will be undertaken from May to July 2018.

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10 Clause 5.16 and clause 5.17 of the NER.

11 See: https://www.aemc.gov.au/rule-changes/replacement-expenditure-planning-arrangements

12 AER, Review of the application guidelines for the regulatory investment tests, Issues Paper, February 2018, p.40.

The outcomes of this project will not directly impact on the design of the Guarantee. However, as noted above, improving the coordination of generation and transmission investment will facilitate the new investment in capacity that the Guarantee will incentivise to ensure the reliability of the power system and so can be considered an "enabler" for reliable outcomes in the NEM.

1.6 Next steps

A final report on this review is due in mid-2018.

1.7 Structure of this paper

This paper is structured as follows:

- chapter 2 provides context for this review
- chapter 3 describes the current transmission framework, and the philosophy that underpins this framework, in detail
- chapter 4 examines potential issues with the current framework, specifically:
  - transmission planning and connection: the scale and cost of congestion in the NEM
  - transmission charging: the treatment of storage
- chapter 5 discusses REZs
- chapter 6 presents conclusions and next steps.

2 Context

How generation and transmission investment is coordinated is important in the context of reliability in the power system. Reliability refers to having enough generation, demand response and network capacity to supply consumers. Therefore, how transmission and generation are coordinated, and the efficiency of this, can be considered an "enabler" for good reliability outcomes in the NEM.

Therefore, this chapter discusses the broader context and background for reliability implications in the NEM, specifically:

- broad challenges to the existing reliability frameworks
- implications for the transmission network
- recommendations from the Finkel Review.

2.1 Challenges to the existing framework

Australia's energy system is increasingly being driven by changing consumer choices and rapidly evolving technology. Meanwhile, various policy settings – including numerous policies to incentivise renewable energy investments – are having a profound influence on consumption, investment and operational decisions across the whole electricity supply chain.

In the context of these challenges, it is worth acknowledging the significant body of work underway that is currently considering how to maintain the reliability and security of the NEM. This includes the Energy Security Board's National Energy Guarantee, the AEMC's *Reliability frameworks review*, the Reliability Panel's *Reliability standard and settings review*, the Reliability Panel's *Review of the frequency operating standard*, the AEMC's *Frequency control frameworks review* and the AEMC's *Generator technical performance standards* rule change.

In addition, in relation to reliability, there are a number of rule changes currently underway by the Commission in March 2018 that seek to make changes to the current framework, including a rule change from AEMO to reinstate the long-notice Reliability and Emergency Reserve Trader, a second rule change seeking broader changes to enhance the Reliability and Emergency Reserve Trader, and a rule change from Dr Kerry Schott AO seeking to introduce a three-year notice of closure for generators.

In the security space, there have been significant changes made to the security frameworks to ensure that they are fit for purpose. The frameworks requiring TNSPs to maintain minimum levels of inertia and system strength to address immediate security issues relative to rates of change of frequency and fault levels will commence 1 July 2018. These frameworks arise from the Commission's *Managing the rate of change of power system frequency* and *Managing power system fault levels* rules. AEMO's first power system frequency risk review, required by the *National Electricity Amendment (Emergency frequency control schemes)* rule was completed in September 2017.

2.1.1 The rise of the demand side

Historically, a 'reliable' power system invariably meant back-up generation, that is, the availability of additional generating units if others failed. However, the emergence of new technologies and ensuing regulatory developments have meant that reliability is no longer the exclusive domain of 'supply-side' solutions. Rather, the demand-side – including residential customers – now has a potentially important role to play in delivering a reliable power system at the lowest possible cost. Indeed, consumers are now better-equipped than ever to manage and control their energy use and contribute to reliability and this will only improve in the future.

The emergence of distributed energy resources such as small-scale photovoltaic (PV) systems (of which there is now around 5,700MW in the NEM) – often assisted by heavily subsidised feed-in tariffs and the small-scale renewable energy scheme– and the steadily declining cost of battery storage means that these technologies may already be an efficient source of generation and back-up capacity in some circumstances (furthermore, relatively broad geographic dispersion generally helps[13]). Those possibilities will expand in the future with AEMO estimating that, by 2036-37, nearly 20,000MW of roof-top solar PV will have been installed, together with more than 5,500MW of residential and commercial battery storage.[14]

Efficient, cost-reflective price signals can also encourage customers to shift energy use away from peak times, avoiding inefficient investments and load shedding events. These signals can be complemented by modern home energy management systems, which can provide a demand response that goes largely unnoticed by the customer. Voluntary load reductions by commercial and industrial users can also potentially be elicited as an alternative to involuntary load shedding. There is a growing body of evidence suggesting that the potential quantum of demand response available in the market is growing.[15]

2.1.2 Changing mix of generation

The approach paper published in August 2017 as part of this review identified that the transition of the NEM to a lower carbon emissions future has implications for both generation and transmission investment. The generation mix will need to change in order to reduce the emissions intensity of the sector. This will require new low emissions generation to be built and may mean that higher emissions generation will retire. The trend of renewable generation entering the NEM is expected to continue.[16]

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13 In the absence of adequate storage capacity, solar PV that is clustered in a single geographic area can give rise to reliability problems. For example, it can result in sudden drops in supply during times of cloud cover when large numbers of plants stop producing all at the same time.

14 AEMC, *Reliability frameworks review*, issues paper, 22 August 2017, Sydney, p. 26.

15 For example, in October 2017, ARENA and AEMO announced that ten pilot projects had been awarded funding under their demand response initiative to manage electricity supply during extreme peaks. In total, the $35.7 million initiative will deliver 200MW of capacity by 2020, with 143 MW having been made available over the 2017-18 summer.

16 AEMO is currently tracking over 45,000 MW of proposed new generation capacity. The technology mix of this new generation is 7.5% gas, 38% wind, 38.6% solar, 11.2% water, 1% biomass, 1% other, and 0.1% storage. See:

The mix of generation in the NEM has been changing rapidly in recent years, leading to a steadily declining percentage of dispatchable generation. These trends have been widely reported and include:

- Variable weather dependent renewable generation in the NEM, including residential solar PV, has increased substantially since 2001. The capacity of variable renewable generation is expected to continue to increase with committed wind and utility solar projects. This has been incentivised by factors such as:
    - generous feed-in tariffs provided by state governments, which have provided strong financial incentives to install roof-top solar PV[17]
    - the large-scale renewable energy target (LRET), which has provided strong additional incentives for the private sector to invest in large-scale renewable generation, particularly wind farms
    - capital incentives provided in terms of credits from the small-scale renewable energy scheme
    - government grants through Australian Renewable Energy Agency and long-term contracts under the Australian Capital Territory Government's reverse auction scheme.[18]
- There has been a trend of thermal (coal-fired) generation exiting, including Northern Power Station in South Australia (520MW in May 2016) and Hazelwood Power Station in Victoria (1,600MW in March 2017). Moreover, the Liddell Power Station in New South Wales (2,000MW) is expected to close in 2022.[19]

At the same time, high gas prices and lack of certainty about an emissions reduction mechanism that is integrated with the wholesale market, have acted as a disincentive to new coal and gas generation.

2.1.3 General policy uncertainty

The challenges described above have been exacerbated by the prolonged considerable uncertainty over a long term emissions reduction mechanism that is integrated with the energy market, which has had a significant impact upon investment in new generation. Although these challenges are not 'emerging' per se – indeed, some of them have existed for some time – their potential impacts on the reliability framework may become more acute as time passes.

https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

17 For example, customers who applied for the Queensland government's Solar Bonus Scheme before 10 July 2012 and maintain their eligibility can continue to receive a feed-in tariff of 44 cents per kilowatt-hour for excess electricity exported to the grid. See: https://www.dews.qld.gov.au/electricity/solar/installing/benefits/solar-bonus-scheme

18 See: https://www.environment.act.gov.au/energy/cleaner-energy/how-do-the-acts-renewable-energy-reverse-auctions-work

19 See https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2017/december/agl-announces-plans-for-liddell-power-station

The proposed National Energy Guarantee seeks to address some of these concerns by implementing an obligation on retailers to do two things - to make sure the energy they are purchasing meets emissions reduction targets for the electricity sector and to meet reliability requirements in each region. The Guarantee would integrate energy and climate change policy, giving investors the much needed certainty they have been lacking over the last decade. Under the proposed mechanism, energy sector development could continue confidently with emissions and reliability objectives implemented in lockstep under the NER.

2.2 Implications for the transmission framework

The shape of the transmission network may need to change to deliver a reliable supply to consumers from the changing generation mix. Historically, the shape of the transmission network was driven mainly by demand growth. Major load centres in the NEM were served by generation clusters in relatively close proximity (such as Melbourne and the Latrobe Valley). Transmission investment within regions was dominated by the need to meet jurisdictional demand-side reliability standards, with the estimation of generator benefits being relatively minor in comparison. In addition, few investments in interconnectors between regions occurred, largely due to the relatively small differences in fuel costs between the regions.

Now, the needs are driven more by the different location, and different type, of new generation investment. This is because typically the best renewable energy resources are more remote from existing transmission infrastructure, which drives where these parties which to locate. Transmission investment may therefore be required, to the extent that it is needed to reliably supply consumers with electricity from these new generation sources.

There is greater uncertainty, and TNSPs are likely to have to assess much greater changes in the pattern of generation in the NEM than previously.

In its submission to the approach paper, the South Australian Council of Social Services (SACOSS) perceived major issues with the current framework for transmission investment, specifically that there is insufficient incentive for networks to propose non-network solutions.[20] SACOSS recommended examination of the option of auctioning of network capacity usage rights, which would give better price signals as to the real value of extra network capacity, and the system used in Argentina where key network users are heavily involved in network augmentation decisions - see Box 2.1.

Box 2.1 Governance model of power transmission in Argentina

Argentina implemented transmission reforms in the early 1990s in preparation for new transmission investments to meet increased demand for electricity. These reforms were designed to increase competition in the market following an

20 The issue of the financial incentives that NSPs face in delivering economically regulated services under the existing regulatory framework is being considered in the AEMC's 2018 *Electricity network economic regulatory framework review*. See: https://www.aemc.gov.au/markets-reviews-advice/electricity-network-economic-regulatory-framew-1

assessment that the existing regulatory framework was inefficient.

New methods for deciding how transmission grid expansions would take place were implemented, the most notable of which was the Public Contest method. Under this approach a group of transmission users (generators, distributors or large power consumers) who are interested in a major expansion of the grid, submit a request to the transmission company. This is then assessed by the regulator through a process that involves many parties and requires a vote of users followed by a competitive tender.

The key feature of the Public Contest method is that the decision on the undertaking of a transmission expansion is given to the users (or 'beneficiaries') themselves – who also pay for the expansion – rather than to the transmission company, the system operator, the regulator or the government. This step in Argentina's reform process of the electricity sector was based on the consideration that if the costs of an expansion were charged to those who used it, then these users would have the incentive – and be in the best position – to identify, propose and accept economic expansions and to reject uneconomic ones.[21]

Some aspects of this process may be able to be applied to the NEM, if it was thought there was a case to do so.

Although not the same as the approval system utilised in Argentina, the RITs process in the NEM does recognise the need for those who pay for the investment to have the opportunity to be involved by making the cost benefit analysis and decisions on major investments transparent.

2.3 Finkel Review

The Finkel Review sought to address the challenge of coordinating transmission network planning and renewable generation investment. One of the three enabling pillars to achieve the Blueprint outcomes in the Finkel Review was "System Planning: enhanced system planning will ensure that security is preserved, and costs managed, in each region as the generation mix evolves. Network planning will ensure that renewable energy resource regions can be economically accessed."[22] Identifying the limited existence of detailed guidance to facilitate the connection of solar, wind or pumped hydro generators to load, the Finkel Review made a number of recommendations for the NEM transmission network, including the efficient development and connection of REZs to be facilitated by an integrated grid plan:[23]

> "Recommendation 5.1 - By mid-2018, the Australian Energy Market Operator, supported by transmission network service providers and relevant stakeholders, should develop an integrated grid plan to facilitate

21 J.P.M. Sim, The governance model of power transmission in Argentina: Energy Research Centre of the Netherlands, October 2015.

22 *Independent Review into the Future Security of the National Electricity Market: Blueprint or the Future*, June 2017, p.9.

23 Ibid, pp.263-264.

the efficient development and connection of renewable energy zones across the [NEM].[24]

Recommendation 5.2 - By mid-2019, the Australian Energy Market Operator, in consultation with transmission network service providers and consistent with the integrated grid plan, should develop a list of potential priority projects in each region that governments could support if the market is unable to deliver the investment required to enable the development of renewable energy zones. The Australian Energy Market Commission should develop a rigorous framework to evaluate the priority projects, including guidance for governments on the combination of circumstances that would warrant a government intervention to facilitate specific transmission investments.[25]

Recommendation 5.3 - The COAG Energy Council, in consultation with the Energy Security Board, should review ways in which the Australian Energy Market Operator's role in national transmission planning can be enhanced.[26]"

24 Work to address this recommendation is on track and scheduled to be completed by mid 2018 with the publication of AEMO's ISP.

25 This recommendation is under consideration through this review process and work AEMO will undertake following publication of the 2018 ISP. It is expected to be addressed by mid 2019.

26 AEMO's role in national transmission planning will be considered by the Energy security Board in due course and in light of other relevant work. This recommendation is expected to be addressed by 2020.

3 The transmission framework in the NEM

This chapter outlines the current transmission framework in the NEM and the philosophy that underpins this framework. The roles and responsibilities of different parties and the decisions that are made by participants in order to fulfil these roles and responsibilities are explained. Finally, the allocation of costs and risks under these frameworks are outlined. The purpose of outlining the current frameworks is to provide context and the basis of comparison for any proposed deviations from the current frameworks.

Put simply, the term "transmission framework" refers to the rules that govern how the transmission system operates and how it interacts with the competitive sectors of the market, in most cases generation but also the demand-side. These rules define the roles and responsibilities of different parties, the risks and costs borne by different parties and how operational and investment decisions are made.

Any framework for the operation of the transmission system, regardless of the design, should have achieving efficient outcomes for market participants, networks and ultimately consumers as its underlying purpose - consistent with the National Electricity Objective. The objective of the transmission framework in the NEM is described in more detail in Box 3.1.

Box 3.1 Objective of the transmission framework in the NEM

The purpose of the transmission system is to transport electricity from generators through to end users in such a way that promotes efficiency. As there are a number of parties involved and a number of desired outcomes there a number of smaller or sub-objectives that underpin this. The transmission framework should work in such a way that the following objectives are achieved:[27]

- **Efficient dispatch of energy and ancillary services including demand response -** This relates to operating the power system in real-time in a way that maximises societal welfare while also maintaining security and reliability, i.e. making sure that demand balances with supply in real-time. This is best achieved through price signals which allow market participants to behave in a way that is consistent with this goal.
- **Efficient maintenance and operation of networks -** In order to achieve efficient dispatch outcomes in the wholesale market, the transmission network needs to be maintained and managed in a way that does not create inefficiently high levels of constraints for generators. On the other hand, networks that are over-maintained or invested in will lead to inefficiencies due to the unnecessary costs involved in providing a return on and recovery of the capital costs involved as well as maintaining the network to this level. In short, it is desirable to maintain a high level of network capacity availability at least practical cost, in order to maximise the potential gains of

27 Putnam, Hayes & Bartlett *Transmission and Distribution Network Pricing Review: Issues Analysis and Options* Final Report prepared for the National Generator Council, 26 March 1998, pp10-11.

trade from the competitive wholesale market.

- **Efficient location of generation and load -** In order to maximise the efficiency of wholesale market outcomes, generators and load should be provided with signals that enable them to make efficient trade-offs between alternative locations and connection points. There are a number of factors that will inform a decision on where to locate, including losses, potential transmission constraints, proximity to existing network infrastructure, connection costs and proximity to fuel or renewable resources.
- **Efficient network augmentation and replacement -** The benefits of network augmentation and replacement should be carefully balanced against the costs to make sure that investment in networks is efficient. As there are likely to be a number of options available to augment or replace the network to meet an identified need, it is important that a range of options are considered in planning for network augmentations and/or replacements in order for the option that provides the greatest net economic benefit to be chosen. Efficient network augmentation and replacement may also require consideration of non-network options such as demand-side investment.
- **Efficient risk allocation -** Network investment is a long-term investment decision and will be driven, in part, by the risks faced by parties. Risks should therefore be allocated to those parties that are best placed to manage them. If parties face artificially low risks, they may have an incentive to overinvest, which imposes excessive costs on the system as a whole. Whereas, parties who face artificially high risks may choose not to undertake an investment, even if this investment is efficiency enhancing and would provide a benefit to society.
- **Efficient regulation -** To the greatest extent possible, markets should be used to provide efficient signals to participants. In situations where markets cannot always deliver efficient outcomes, such as in the provision of natural monopoly network assets, regulation may be desirable.

The current transmission framework has been designed with the above overarching objective in mind and can be described in broad terms by the following key features:

- parties have a right to negotiate a connection to the transmission network, but no right to earn revenue in the wholesale market i.e. there is an open access framework for generators
- transmission networks have to meet jurisdictionally-set reliability standards that reflect a trade-off between the cost of building and maintaining the networks and the value placed on reliability by customers, which are defined in terms of serving customer load
- end-use consumers pay for costs incurred by the TNSP in providing shared transmission services from which they benefit, including the investment and operational costs which is reflected in a transmission company's revenue that is recovered from consumers and which is regulated by the AER

- generators pay only for the costs of the services provided to them by the transmission business to facilitate their connection to the transmission network
- transmission businesses plan the network, which assists in identifying the solutions to network issues in a timely manner, with AEMO as national transmission planner providing an independent, strategic view of the efficient development of the NEM transmission grid
- augmentation and replacement decisions relating to the network are subject to cost-benefit tests (regulatory investment tests) to assess whether the investment or replacement will create a net market benefit for consumers.

It is important to view the above features together as part of a holistic framework. This is because each feature of the current framework has implications for others. For example, since reliability standards or networks are defined in terms of providing reliable supply to consumers it is appropriate for consumers to pay the costs of the transmission business in return for this reliability. In short, any changes to one part of the framework need to be considered with respect to its implications for the framework as a whole.

Each of these design features is described in more detail below.

Open Access

The access arrangements relate to how parties connect and use the physical assets that comprise the transmission network. Specifically, they refer to the rules governing connection to and use of the physical infrastructure for the transport of electricity i.e. chapter 5 of the NER.

Currently, there is an open access regime.[28] Generators have the right to negotiate a connection to the transmission network, but no right to the regional reference price, i.e. there is no firm access. The service that a connecting generator is ultimately negotiating for with a TNSP is power transfer capability at the connection point.

Given this, generators only pay for the costs of the services provided to them by the TNSP to facilitate their connection to the transmission network, i.e. a connection charge that relates to the cost of their immediate connection to the transmission network.[29]

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28 This is currently confused by rule 5.4A of the existing NER, which implies that generators are able to negotiate a form of firm financial access with the incumbent TNSP in the event that it is constrained on or off, in return for an access charge. This rule is unworkable due to the fact that all generators have open access to the transmission network and that the scheme is not mandatory. Therefore, the Commission recently removed rule 5.4A of the NER, effective 1 July 2018, in order to remove this confusion. For further details on this see section 4.1 of the following document: AEMC, *National Electricity Amendment (Transmission Connections and Planning Arrangements) Rule 2017*, Rule Determination, 23 May 2017. See: https://www.aemc.gov.au/rule-changes/transmission-connection-and-planning-arrangements

29 The Commission recently made a rule that establishes a transparent and efficient framework for the management of power system fault levels, also known as 'system strength', in the NEM. As part of this framework a new requirement was introduced on new connecting generators to "do no harm" to the security of the power system, in relation to any adverse impact on the ability of the power system to maintain system stability or on a nearby generating system to maintain stable operation, in accordance with AEMO's system strength impact assessment guidelines. For example, this could involve them paying costs to remediate the network for the impact they cause. For further information see: AEMC, *National Electricity Amendment (Managing power system fault levels) Rule 2017*,

From 1 July 2018 new rules will commence that clarify the types of costs to be borne by generators, and which assets required for connection could be provided by the TNSP and by the generator (or by a third party).

So while generators can receive a connection to the transmission network, they have no guarantee that they can export all of their output to the system at any given time - there is no "firm access" to the market.

Instead, scheduled and semi-scheduled generators earn money by being dispatched through the wholesale market that is run by AEMO. Generators sell, and market customers buy, all of their electricity through the wholesale spot market, which matches supply and demand instantaneously.

Scheduled and semi-scheduled generators and loads offer and bid into the market dispatch engine, operated by AEMO. Once these offers and bids are received, AEMO then forecasts the expected customer demand for electricity in each region for each five minute interval. Then, based on an optimisation process, it seeks to optimise outcomes by attempting to maximise the value of trade given the physical limitations of the power system. These physical limits are otherwise known as "constraints," which restrict how much electricity can flow over a particular piece of equipment while preserving its integrity. Through this process, AEMO dispatches as much generation as necessary to meet the demand. Therefore, generators do not have a firm inherent right to be dispatched, instead whether they are dispatched or not depends on the outcome of this process.[30]

Each generator in a particular region receives revenue at the clearing price (known as the "regional reference price", discussed further below) for the electricity delivered - even when that clearing price is above the quantity it offered into the market. In this way, the spot market coordinates the physical dispatch of generation and all generators earn at least their offer for each unit of electricity delivered.

If a generator is not dispatched, then they cannot earn revenue from the spot market. Since the generators have no rights to earn revenue in the wholesale market, they also do not have a right to be compensated for not being dispatched.

The NEM comprises five interconnected electrical regions: Queensland, New South Wales (including the ACT), Victoria, Tasmania and South Australia. There is a designated regional reference node in each region, where the regional spot price of electricity is set.[31] The regional reference price is based on the marginal cost of energy for supplying a particular point in the NEM (known as the "regional reference node"). It is at this point that intra-regional and inter-regional generator bid prices are compared, and where the regional reference price is set. The regional reference node is typically at a major demand and/or generation centre.

Rule Determination, 19 September 2017. See: https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

30 With the exception of non-scheduled generators, who effectively receive priority access to the regional reference node.

31 See for example, clauses 3.2.2(e) and 3.4.1 of the NER.

Market participants' bids and offer prices are referred to the central reference node using transmission marginal loss factors and distribution loss factors to determine comparative prices for dispatch and pool settlement purposes.[32]

Since the NEM has five regions in which a wholesale price is set, it is not considered to be a fully nodal system where *all* locations or nodes in the transmission network would have a price associated with them to reflect the local marginal value of supplying energy at that particular point. Nodal pricing is explained in greater detail in Box 3.2below.

Box 3.2 What is nodal pricing?

Under a full nodal pricing model, generators would be settled by default at their locational marginal price (LMP), but would have the option to purchase fully financially firm access rights to another node. In this case, the concept of NEM regions and settlement against a regional reference price (RRP) would no longer be applicable. Under this approach, differences in LMPs would reflect the costs of network congestion.

In a nodal system, generators are paid the marginal cost of generation at their transmission node based on a merit order dispatch. Nodal prices more accurately signal the value of electricity at each location, and do not impose the same perverse incentives on bidding that can be a feature of regional systems. They therefore are considered to deliver the best dispatch outcomes in the presence of transmission constraints.

Nodal pricing is common in international jurisdictions, including many US and European markets.

When the NEM was developed, it was considered that while marginal pricing of delivered energy would provide the best support for economic efficiency objectives, complete implementation of this principle to a fully nodal arrangement would be too complex, and so a modified, simplified framework was subsequently adopted.

Therefore, the NEM represents a simplified nodal pricing framework - while participants settle on a regional price, the dispatch of generation, and so AEMO's optimisation, takes into account both energy losses as well as constraints on the transmission network.

While participants settle on one price in a particular region, prices can and do vary between the regions. Price divergence between the regions principally reflects constraints on the free transfer of electricity since regions are connected by interconnectors, with limited capacity.

Closely related to whether or not generators are dispatched, and so whether or not they are able to earn revenue from the wholesale spot market at a particular time is how congestion or constraints in the network are managed. Congestion is explained in more detail in Box 3.3 below.

32 See for example, clauses 3.2.2 and 3.6.2 of the NER.

Costs of transmission congestion cannot be separated from the cost of generated energy, since congestion has implications for generation dispatch. For example, if there is congestion somewhere on the network, a generator may not be dispatched since it will not be able to physically access the system - to do so would create security concerns, and so the generator will be "constrained off". However, in preserving the integrity of the transmission system by constraining off a particular generator, it may result in a higher cost generator being dispatched instead in order to satisfy demand. This would move the generator dispatch away from an unconstrained, least-cost merit order. Therefore, the opportunity cost of transmission congestion depends on the marginal cost of power at different locations, with these costs determined simultaneously through dispatch processes and the spot market.

Box 3.3 What is congestion?

The carrying capacity of transmission networks is limited. The designed capacity is a deliberate decision - representing a trade-off between cost and reliability:

- higher transmission network capacity is expensive to provide, but results in lower amounts of congestion
- lower transmission network capacity is cheaper to provide but results in higher amounts of congestion.

Therefore, the key is to strike a balance between not having too much congestion, but maintaining reasonable costs for electricity customers.

Congestion occurs when the flow of electricity reaches the physical limits of the transmission network (or a particular part of it). At these times transmission capacity becomes scarce. The primary consequence of congestion on the transmission network is that it can cause some generators to be “constrained off” (i.e. be unable to get access to the market) and some generators to be “constrained on” (i.e. be required to produce) to ensure demand continues to be met.

A generator is said to be constrained off when it is dispatched for a quantity less than the amount it desired to produce at the market price. Conversely, a generator is said to be constrained on when it is dispatched for a quantity greater than the amount it desired to produce at the market price.

Typically, there has not been significant congestion within a region, generators have rarely been constrained-on, and the imbalances have been managed through the dispatch process. However, theoretically, network congestion leads to the potential for "dispatch risk" for generators, whereby they face a risk of not being dispatched (and so not being able to access the market) even when they are one of the lower cost generators due to the network congestion. Generators can limit the extent to which this happens through their offers into the market, but, cannot fully manage this risk due to the lack of firm access rights over the shared transmission network in the NEM. The risk of not being dispatched (i.e. not getting access to the wholesale market) is one factor that contributes to why most generators do not fully sell their output in contracts in the financial derivative markets. As a rule of thumb, generators typically contract for only 3 out of their 4 units.

Network reliability standards for consumers

Transmission businesses must make investments or procure services to meet the relevant jurisdictional reliability standard. Reliability standards relate to how transmission and distribution networks can withstand risks without consequences for consumers and guide the level of investment that network businesses undertake. These standards are set by state and territory governments and reflect a trade-off between the cost of building and maintaining the networks and the value placed on reliability by customers, which is defined in terms of serving customer load. These standards generally ensure a level of redundancy in the system, implying that the supply of power to total load (i.e. customers) will be robust in the event of a certain level of risk, or contingency.[33]

The reliability standards that networks are required to meet are therefore defined in terms of reliably supplying customer load. Therefore, the focus of TNSPs, including their operation and investment decisions, is to deliver a reliable supply of electricity to consumers. Their focus is also to make offers to connect generators and loads that wish to connect to the network consistent with the open access regime described above.

Since the network reliability standard relates to consumers, it can be considered that consumers have an implied access right to the transmission network.

There is no reliability standard for generators. When a generator is considering investing in a new plant, it has no means of managing the risk of congestion associated with that plant in the future (although it will factor in to estimates of the generator's congestion risk, which is an input to the financial modelling that underpins the investment).

As described above, the generator could be constrained off at any point in time depending on the offers of other generators, and the physical limitations of the system.

The regulatory regime does include the ability for generators to fund network augmentation (known as a funded augmentation), but we understand that these have not commonly been used except in the case of some lower value projects. This is because with these investments there is no guarantee that a future generator will not connect and cause renewed congestion. Even if a generator funded an augmentation to the transmission network it would have no ability to obtain any physical or financial rights in relation to that piece of the network. A new generator could come along, connect, and constrain off the existing generator.

Consumers pay transmission charges

The above two features of the current framework (no right to be dispatched, and the fact that consumer needs drive network reliability standards) drive decisions about who pays for the transmission network:

33 Victoria uses a probabilistic planning approach where there is not a deterministic reliability standard that must be complied with. Instead, AEMO plans its network on a project by project basis, and in doing so considers whether the economic value of the benefits associated with the project exceeds the costs. For further information on the planning arrangements in Victoria, see Box 3.4.

- since generators do not directly drive development of transmission infrastructure to enable the export of energy from generators, they do not pay any form of charges for the transmission network
- but, because there is an obligation on transmission businesses to reliably supply their customers, it is consumers (either directly, or indirectly through their retailer) who fund investments in the transmission network and so pay TUOS charges.

The issue of transmission charging, and who pays for services provided by transmission networks, is inherently tied up with what service is provided to the various parties through the transmission network. Since generators do not currently receive any guaranteed service or firm access from the transmission network, they therefore do not pay transmission charges.

Under chapter 6A of the NER, there are pricing provisions which set out how TUOS charges are to be recovered from consumers. These are based on a set of pricing principles and require TNSPs to develop separate prices for each category of fully economically regulated ("prescribed") transmission service. Each TNSP must also publish a pricing methodology which, in part, sets out how the revenue to be recovered has been allocated to each category of prescribed transmission service.

The majority of the TUOS services component of prescribed transmission services is recovered in the form of either a locational or non-locational charge. The split between the locational and non-locational components of TUOS services can be either on a 50:50 basis (standard cost reflective network pricing), or based on a reasonable estimate of future network utilisation and the likely need for future transmission investment (modified cost reflective network pricing), which has the objective of providing more efficient locational signals.[34]

In addition to charging customers within their region for use of the transmission system, the NER includes inter-regional transmission charging arrangements. This charge is levied by TNSPs in the electricity exporting region on the TNSP in the importing region of the NEM. The charge is recovered from the customers in the importing region. The amounts recovered from the inter-regional transmission charge are then passed on to consumers in the exporting region in the form of lower transmission charges. This charge improves the cost-reflectivity of transmission charges and the allocation of costs across regions.

An implication of the transmission charging regime is that since consumers pay for transmission, any proposed network investment in the network must be shown to provide market benefits or be necessary to maintain a reliable supply of electricity to network customers. Consumers should not bear the risk of speculative investments or investments that are for the sole benefit of generators (if such an investment would, for example, relieve congestion for generators but not to the extent that it provides an overall market benefit through a reduction in wholesale electricity costs). Congestion is therefore only likely to be built out if a proposed augmentation passes the necessary

34 NER clause 6A.23.3(a)(1)-(2).

regulatory investment test or if it is required to meet load reliability standards.[35] This is discussed further below.

At the initial design stage of the current market arrangements there were some concerns noted that levying network charges on customers would provide "little incentive for the efficient location of investment in network or generation options".[36] It was further noted that locating generation facilities close to load could result in significant network savings, but that if the network charges do not enable the owners of generation assets to benefit from this saving (through reduced network charges), this incentive is lost or muted. However, it was decided that on balance this potential inefficiency could be minimised with an effective access regime with efficient regulations and efficient network pricing.[37]

However, this disconnect between load customers paying TUOS charges and generators only paying the costs associated with facilitating their connection may require reconsideration in the context of an increasing amount of large scale batteries seeking to connect in the NEM. For example, continuation of the current arrangements without clarity could create confusion and perverse incentives for proponents of large scale batteries. This issue is discussed in more detail in chapter 4.

Connecting to the transmission network

As noted earlier, generators have the right to negotiate a connection to the transmission network and pay only the costs associated with facilitating their immediate connection to the shared transmission network. This connection charging arrangement is directly related to the fact that generators do not gain any access rights to the market when they connect.

The Commission recently made a final determination to improve transparency, contestability and clarity in the transmission connection framework while maintaining clear, singular accountability for shared network outcomes, as well as enhancing the transmission planning and decision-making framework.[38] As part of this rule change, the Commission comprehensively reviewed the transmission connections process and affirmed that generators only pay for the direct costs of their connection.

The decision of where new generation (or load) should connect to the transmission network is a commercial one. Connecting generators face a number of market signals that they can use to assess the relative merits of locating at a given point in the network. These include:[39]

- **the cost of connecting to the network:** Under the existing connection charge regime, generators bear the cost of their connection to the shared network. This

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35 The current incidence and cost of congestion in the NEM is examined in more detail in chapter 4.

36 ACCC Determination Authorisation of National Electricity Code, 10 December 1997, p159

37 In any event, generators are exposed to some market-based signals that can determine their locational decisions. These are discussed in more detail in the next section.

38 AEMC, *National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule 2017*. See: https://www.aemc.gov.au/sites/default/files/content/906c54d0-8546-4a83-8172-2a5fb4d5bd93/Final-determination.pdf

39 AEMC *Transmission frameworks review* first interim report, pp. 30-31.

may include the costs of meeting generator access standards, which may vary with local network conditions, as well as any costs associated with remediation for system strength. In addition, factors behind the connection point, such as any requirement to construct any line from the generator's facilities to the network, may be significant and inform the choice of location.

- **the expectation of the presence of congestion:** As discussed above, generators are exposed to "dispatch risk". The frequency and materiality of congestion will influence a generator's ability to access the market, and may provide a signal of where not to locate.
- **marginal loss factors:** Electrical energy losses on the transmission network between a generator's connection point and the regional reference node will influence the outturn price it receives for its energy.[40]
- **inter-regional price differences:** Price separation between regions can be an indicator of which regions require additional generation capacity.

In addition, generators will take into account other non-energy market signals such as access to fuel and cooling water, and environmental planning and development requirements. These non-electricity market factors can have a significant impact on overall costs, particularly the proximity of a preferred location to a fuel source.

An important implication of the philosophy behind the transmission framework in operation in the NEM is that generators are responsible for the costs of their connection at the time of their connection. Generators bear the cost of connecting to the network and do not bear a responsibility for future developments, including the impact of retirement of generation. Connecting generators should also not be asked to bear any costs that would facilitate the connection of future generators to the network. This is because generators have no rights to be dispatched and earn revenue in the wholesale market. It is also the case that TNSPs are unlikely to undertake major investments to relieve congestion or to make certain that generators can access the regional reference price unless it is also required to do so to deliver a reliable supply to consumers.

Transmission planning

Transmission network planning is an important element of the overall framework that aims to identify and plan for efficient future network investment. Transmission planning also plays an important role in providing market participants with information on likely future developments in the transmission network. Currently, transmission planning takes a number of different forms and covers a number of time horizons. Long-term planning focuses on long-term expected generation and demand, and therefore on long-term transmission network investment and replacement needs to reliably supply consumers. Short-term planning has a focus on the near term and specific investment and replacement needs. Project specific planning relates to a particular investment need and culminates in an investment or replacement decision (this is discussed in the next section).

40 Loss factors in the NEM are determined on an average basis and set annually. Therefore, they will not always provide an efficient signal.

At a high-level, the current transmission planning approach in the NEM involves a continuous feedback loop of information whereby AEMO publishes an annual National Transmission Development Plan (NTNDP)[41] followed by each TNSP publishing their annual planning report. In each of these reports, both network and non-network developments must be considered to meet future needs.[42]

AEMO is the national transmission planner and conducts long-term strategic planning across the NEM. This planning process results in the publication of the NTNDP, which provides a vision of the transmission network over the next 20 years. The NTNDP uses a range of scenarios to examine the efficient development of the national transmission grid.

In the NEM, it is clear that responsibility for investment and replacement decision making sits with the TNSP[43] itself, with the TNSP using the output from AEMO, as the national transmission planner, as an input. In particular, part B of chapter 5 of the NER sets out planning and reporting requirements for network service providers. Under these requirements, a TNSP is to undertake an annual planning review to identify emerging network constraints expected to arise over a ten-year planning horizon. The results of a review are then published in its transmission annual planning report, which must (amongst other things) set out what the TNSP is doing to meet its reliability standards.

Box 3.4 Transmission planning in Victoria

Victoria is the only jurisdiction where AEMO has declared network functions. In Victoria, the functions undertaken by TNSPs elsewhere are split between AEMO and Declared Transmission System Operators (DTSOs). AEMO is accountable for the provision of the shared network, procuring services from DTSOs (such as AusNet Services), who own and operate the shared assets.

Under the NEL, jurisdictions can declare AEMO to have declared network functions. AEMO's declared network functions include:

- to plan, authorise, contract for, and direct augmentation of the declared shared network
- to provide information about the planning process for augmentation of the declared shared network
- to provide information and other services to facilitate decisions for investment and the use of resources in the adoptive jurisdiction's electricity industry
- to provide shared transmission services by means of, or in connection with, the declared shared network
- any other functions, related to the declared transmission system or

41 Currently being called an "Integrated System Plan".

42 AEMO, *Integrated System Plan Consultation Paper* p.12.

43 Typically called the jurisdictional planning body, which is generally the regional TNSP, with the exception of Victoria, where AEMO is the jurisdictional planning body.

electricity network services provided by means of or in connection with the declared transmission, conferred on it under the NEL or the NER

- any other functions, related to the declared transmission system or electricity network services provided by means of or in connection with the declared transmission system, conferred on it under a law of the adoptive jurisdiction.

The Finkel Review identified some potential enhancements that could be made to the current transmission planning process. In particular, recommendation 5.1 of the Finkel Review final report stated that:

> "By mid-2018, the Australian Energy Market Operator, supported by transmission network service providers and relevant stakeholders, should develop an integrated grid plan to facilitate the efficient development and connection of renewable energy zones across the National Electricity Market (NEM).[44]"

This recommendation implies an enhanced role for AEMO as national transmission planner to identify a series of potential transmission investments across the NEM. The motivation behind this recommendation was that under the current framework there is not sufficient coordination of transmission planning at the national level. AEMO note in the consultation paper for the ISP that "[w]ithout a coordinated long-term "national interest" perspective, there is a material risk this could result in uncoordinated development of regional energy infrastructure, which could impose inefficient costs on consumers at times when lowering energy prices is a national priority".[45]

In developing the current planning framework, it was acknowledged that economies of scale and scope of transmission networks complicate longer-term planning and investment, since there are cost savings from integrating otherwise separate investment projects.[46] This issue will be discussed in more detail in the discussion of REZs in chapter 5.

Network augmentation

As mentioned in the previous section, TNSPs are required under the NER to conduct a cost-benefit test for specific projects (subject to a cost threshold). This test considers the benefits to market participants and consumers of a particular investment.

The most recent version of the cost-benefit test, the regulatory investment test for transmission (RIT-T), was implemented in August 2010. Under the RIT-T, TNSPs are required to assess the efficiency of proposed augmentation and replacement investment options (that exceed $6 million in value) by estimating the benefits that would result for market participants and consumers, and comparing these to the associated costs. The purpose of the RIT-T is to identify the transmission investment or replacement option

44 *Independent Review into the Future Security of the NEM: Blueprint for the Future*, June 2017, p.124.

45 AEMO, *Integrated System Plan Consultation Paper* p.12

46 London Economics, *Review of Australian transmission pricing* A report for the Australian Competition and Consumer Commission, April 1999, p.13

which maximises net economic benefits and, where applicable, meets the relevant reliability standards.

The framework for assessing options for network augmentation or replacement is designed to protect consumers, who bear the costs of transmission, from the risk that this investments or replacements are inefficient. However, in the context of the current large amount of new, mostly renewable, generation that is expected to connect to the network in the medium term, the appropriateness of RIT-T framework is being considered by some parties. AEMO note in the ISP that:

> " ... TNSPs are generally incentivised to build network infrastructure if it can be incorporated into their regulated asset base (RAB). Uncertainty over the amount of new generation development which will occur in certain regions means assessments through RIT-Ts have so far only led to incremental network augmentations, to manage the risk of under-utilised assets if new generation developments did not materialise to the same extent forecast. This could prove more expensive for consumers than building the network at an appropriate scale in the first place.[47]"

As noted above, the Finkel Review concluded that there may be some benefits to incorporating a more holistic or national view into TNSP investment decisions. AEMO's 2016 NTNDP examined the overall national benefits of combining some proposals for transmission augmentations identified by TNSPs, and highlighted the need for coordination and national planning perspectives when assessing these major augmentations. AEMO's preliminary modelling has found that major transmission upgrades are more economic when combined with other major upgrades, creating a more interconnected NEM.[48]

Any changes to the process for assessing network augmentations or replacements should balance both the potential for efficiency to be maximised against the appropriate allocation of the costs and risks of network investments. The current framework is set up around not exposing consumers to any undue risks associated with anticipatory investment in network infrastructure. If an investment is made on the basis of an expectation that new generation will locate in a particular area of the NEM, consumers will bear the risk that this expectation is wrong and the asset becomes stranded.

There may also be risks involved with specifying a series of investments that are dependent on one another in order to provide benefits to consumers. While a staged approach to large changes to the shape of the transmission framework may be a prudent approach, there should be flexibility to change course if the assumptions used in defining the timing and sequence of such investments turn out to be incorrect. These issues are discussed further in chapter 5 in the context of REZs.

Co-optimising generation and transmission decisions

Generation and transmission are both complements and substitutes. This implies that investment and operational decisions by generators and TNSPs should work together to achieve overall efficient outcomes.

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47 AEMO, *Integrated System Plan Consultation Paper,* p.24

48 AEMO, *Integrated System Plan Consultation Paper,* p.40.

Generation and transmission are dependent on each other to achieve their individual objectives. Generators need the transmission network in order to access the wholesale market and earn the regional reference price for their generation output. TNSPs need sufficient generation to reliably supply their customers and to meet their individual reliability standards.

Expansion of the transmission network needs to support generation investment decisions, and generator decisions on where to locate need to take into account any requirement to construct additional transmission network. Similarly, operational decisions should be co-optimised such that least cost generation can be dispatched, taking into account network constraints and losses.

Therefore, the incentives and regulatory obligations that inform generator and TNSP behaviour need to be considered together as a consistent package in order to deliver efficient outcomes. The policies that guide transmission investment must be consistent with both the policies that guide operational decisions by TNSPs and the type and structure of market signals that guide investment and operational decisions by generators.

It is clear that TNSPs and generators have different incentives and priorities when making their respective investment decisions. The decision-making of generators and TNSPs occur separately and under different conditions. Generator decision-making is market-driven and seeks to maximise the profits for the generation business. Network investment is based on a regulatory process that is designed to allow TNSPs' sufficient revenue to meet their statutory and regulatory obligations to reliably supply consumers.

Efficient coordination of transmission and generation investment typically requires:

- information being exchanged between the generation and transmission sectors
- that information being timely and meaningful to the recipients
- that the appropriate party bears the cost that it imposes on the transmission network
- that investment decisions by each generator and TNSP incorporate this information and are efficient in light of that information.

It is important that information flows in both directions between the generation and transmission sectors. Currently, expansion of the transmission network supports generation investment decisions, to the extent needed to reliably supply consumers, and generator decisions on where to locate need to take into account constraints and costs on the transmission network. Similarly, operational decisions are co-optimised such that least cost generation can be dispatched, taking into account network constraints and losses.

However, increasing the efficiency of coordinating generation and transmission investment would contribute to efficient investment in both networks and generation. This is most likely to occur when:

- the combined costs of generation and transmission are taken into account in investment and operational decisions by generators and TNSPs, leading to lower costs overall

- parties that make investment decisions have a direct financial stake in the efficiency of outcomes resulting from these decisions.

Further, it is worth noting that the Commission prefers market-based solutions to centrally planned or mandated ones. Centrally-planned solutions rely on a centralised agency making a decisions about the coordination of transmission and generation investment, which will likely foreclose the considerable potential benefits of a well-functioning market, and may result in trade-offs being made between different objectives by governments on behalf of consumers. It also means that consumers, not competitive businesses, bear the costs of investment risk.

On the other hand, markets provide incentives to innovate, which benefits consumers. This is because competitive pressures are thought to drive more cost-effective and efficient investment and consumption decisions, and because the iterative process of many participants transacting allows for greater responsiveness to changing information and circumstances.

Options to improve the coordination of generation and transmission investment

At the start of stage 2 of this review, the Commission identified a spectrum of options that could be used to coordinate generation and transmission investment in the NEM. The first four are focussed around transferring some of the risks anticipated with transmission network spend from consumers to generators in return for financial access; while the latter two options focus around options to better facilitate transmission planning outcomes in the NEM. These are outlined below:[49]

- **Generator transmission access standard:** This would be similar to the reliability standard which already exists for load. The standard would give generators greater visibility regarding their likelihood of being dispatched in a given location. The standard would not provide a specific access right to individual generators, but would more likely provide an "average" level of access within a defined geographic zone. In other words, generators would not be able to choose their access standard. TNSPs would face a regulatory requirement to meet the standard. Generators would pay generator transmission use of system charges in return for receiving this access.
- **Optional firm access:** This would allow generators to purchase a partially firm financial access right to the regional reference node, at a regulated price in order to manage the financial impacts of network congestion. Generators would be entitled to compensation if constrained below their level of firm access. This would change the way in which transmission and generation investment decisions are made, and would mean generators would bear more of the risk associated with some transmission investment. In effect this would introduce firm transmission rights, while providing locational (nodal) pricing signals to generators.
- **Locational marginal pricing, with deep connection charges:** This would establish sub-regional pricing, and generators would have access to their locational marginal price, but would also be able to purchase optional fully firm

49 These options have been informed by analysis conducted by Cambridge Economic Policy Associates on behalf of the AEMC.

financial access to defined trading hubs. In order for generators to be able to acquire access rights beyond those available through the existing system, they would have the option of paying deep connection charges[50], for which they would also receive optional *fully* firm access. In essence, this option would provide generators with fixed financial access, compared to optional firm access where only firm financial access would be provided (i.e. there would be times under an optional firm access model where there would be operating conditions under which the capacity of the transmission network would be reduced and so access for firm generators might also correspondingly be reduced. The deep connection charge would not reflect locational differences in costs.

- **Locational marginal pricing, with generator transmission use of system charges:** This would be the same as the previous option, however there would be no deep connection charges. Rather, a transmission use of system charge would be used to send locational signals reflecting the incremental cost of market access in specific locations.
- **REZs:** This would create a planning process to identify specific new energy zones for the connection of new generation, with the intention being to allow the transmission investment to those zones to be planned in a cost-efficient way. Such an option was identified by the Finkel Panel as being the best way to coordinate transmission and generation investment in the NEM.
- **Cluster planning:** This would involve a clustering or group consideration of transmission network connection requests, allowing TNSPs to coordinate generator connections based on what delivers the most efficient outcome. Connection applications would be accumulated over time, and then jointly assessed. This is discussed in more detail in section 5.8 and could potentially be considered a subset of the REZ option discussed above.

Box 3.5 What is optional firm access?

Optional firm access would change the way in which transmission and generation investment decisions are made, and would mean generators would bear more of the risk associated with some transmission investment. Generators could choose to pay for a specified level of access to the transmission network in order to manage the financial impacts of network congestion. Specifically:

- Generators would fund and guide the development of new transmission, which would underpin their access rights, both within regions and between regions.
- Generators would bear the indicative costs of transmission development undertaken to support their access decisions.

50 Under a deep connection approach, when a generator connects to the transmission network its connection charges are determined individually and independently from other generators' connection charges, based on the costs of its dedicated assets, other connection-related assets and the costs it imposes on the shared network. This provides a locational signal as generators face the costs that they impose on the network. The deep connection charges may be paid by the generator as a lump capital sum or an annual annuitized value of that lump sum.

- Generators would have the option of purchasing a level of firm access rights to manage congestion risk, which might be for all or part of their generating capacity. These financial rights would entitle the holders to receive compensation payments when congestion occurs. The payments would be funded by those generators who were dispatched in excess of the level of firm access rights, if any, that they have purchased.
- Generators would have the option of not holding firm access rights for any generating capacity. Such generators would not bear any costs of transmission developments.

As noted above, the Finkel Review sought to address the challenge of coordinating transmission network planning and renewable generation investment, specifically focussing on the option of the development of REZs to facilitate the connection of new renewable generators to the transmission network. AEMO is currently progressing the Finkel recommendation to more strategically plan the transmission grid through the ISP process. State governments and industry led projects are also exploring the implementation of zones devoted to renewable energy generation.

Therefore, while there may be a spectrum of options that could potentially better coordinate generation and transmission investment the Commission has focussed its attention on considering REZs since this was the option identified by the Finkel Panel.

The Commission also recognises that stakeholders are currently responding to potential wide-ranging reforms to the security and reliability frameworks in the NEM, and as such there may currently be limited appetite to explore the other options outlined above. Chapter 5 therefore considers the concept of REZs, and how they could fit within the current regulatory framework.

The Commission welcomes stakeholder feedback on whether or the above options discussed above should be considered further.

4 Potential issues with the current framework

Submissions to the approach paper highlighted two potential issues with the current transmission framework that may impact the coordination of generation and transmission investment:

- In relation to transmission planning and connection: potential future congestion;
- In relation to transmission charging: the treatment of storage.

These are discussed in this chapter.

4.1 Congestion in the NEM

The issue of congestion management in the NEM has been the subject of ongoing debate since the establishment of the NEM in 1998. Since NEM start there have been twelve major reports and reviews dealing with various aspects of congestion management and generator access.

As discussed in Chapter 3, the costs of transmission congestion cannot be separated from the cost of generated energy, since congestion has implications for generation dispatch.

There is limited information available on current and recent patterns of congestion in the NEM. It is important to know the incidence and cost of congestion in order to estimate the scale of the problem. The scale of the problem will reveal what potential regulatory reforms, if any, are suitable to address any identified problems with the current framework. This section seeks to provide an estimate of the incidence and cost of congestion that currently exists in the NEM.

As part of this work the AEMC has engaged Ernst & Young (EY) to assess patterns and costs of congestion in the NEM. Some specific questions this analysis addresses include:

- What are the patterns and materiality (volume) of congestion, both inter-regional and intra-regional, in the NEM?
- What are the estimated economic costs of congestion in the NEM?
  - Are there significant variations between the regional reference price and (implied) nodal pricing?
  - What has the impact of mispricing been on dispatch costs?
  - How has congestion impacted on wholesale market prices? This question also seeks to address the impact of congestion on consumers.

Methodology

In order to complete this analysis, EY used the following methodology:

- A regional model of the five regions of the NEM (excluding Tasmania)[51] was constructed for the whole of the 2016/17 financial year, at five minute dispatch intervals, using historical data on demand, offers and bids, dispatch and non-scheduled unit traces from AEMO. The objective of the model is to replicate historical congestion in the NEM.
- This model is verified against observed historical interconnector flows.
- A fully nodal model of the NEM (excluding Tasmania) was also constructed. Implied locational marginal prices for all 1063 nodes above 110 kV (including 110, 132, 220, 275, 330 and 500 kV) in the NEM were calculated.
- A number of constraints were added to the model. These constraints include thermal and stability constraints.
- An iterative process was undertaken whereby binding constraints are reviewed and refined in order to accurately reflect historical congestions patterns in the NEM.

As with any modelling exercise, a series of simplifying assumptions were used to calculate the scale and cost of congestion in the NEM. In particular, the following assumptions and simplifications were used:

- Frequency control ancillary services constraints were not included in the analysis.
- Congestion on lines with capacity below 220kV was not included.
- Dynamic line limits, such as season variations in line loadings, were not fully represented in the analysis.
- Dynamic events that took place in February 2017 (high demand days in South Australia and New South Wales) were not fully represented in the modelling.
- Tasmania was not included in the nodal model.[52]
- AEMO's short-term projected assessment of system adequacy constraint set was used. There are a number of limitations associated with this data set.[53]

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51 Tasmania is still included in the model, however is modelled as a single node at its regional reference node (the same way AEMO models it for dispatch). Historical bids are used for the generators in Tasmania.

52 The nodal model is not used in Tasmania, so no inter-regional congestion within Tasmania is captured. There is often congestion on the Basslink Interconnector, depending on the bidding strategies adopted for the Tasmanian generators relative to the Victorian generators, with the operating limits of the Basslink Interconnector being a hard constraint.

53 The limitations of the short-term projected assessment of system adequacy constraint set are that the equations used differ in some respects from the national energy market dispatch engine constraint equations that are used for actual dispatch of the generators. In particular, some of the national energy market dispatch engine constraints are feedback constraints, where the power is being measured by the supervisory control and data acquisition system many times in each dispatch interval. The feedback constraints focus on shifting the output of generators by only the minimum amount to provide least cost dispatch. Whereas, in the short-term projected assessment of system adequacy, the dispatch calculations are computed individually for each five minute dispatch interval as there are no feedback values to allow the dispatch to be tracked. There are other simplifications in the short-term projected assessment of system adequacy data set but they are the

Overall, these simplifications should not affect the analysis materially. For example, in terms of capturing the FCAS constraints in the model, the impact on the energy dispatch of generators is unlikely to be significant, as FCAS constraints apply across all regions (except for South Australia) and so are not location dependent. Further, congestion below 220 kV could cause localised nodal prices to vary from the regional reference node in practice, but is unlikely to have a material effect on the overall cost of congestion.

The outputs of this modelling exercise are the model of the NEM (regional model) that is benchmarked against actual historical outcomes and the nodal price model which calculates a locational marginal price for each location in the NEM.[54] By comparing the prices at the regional level to the locational marginal prices some areas of congestion can be identified.

In addition, the modelling work also estimates the historical costs of congestion in the NEM. The methodology for this work uses the historical bids for each generator and calculates the MWh of production by each generator for two cases:

- With nominal regional constraints only, and thus with the minimum amount of congestion with the notional interconnectors operating.
- With the national energy market dispatch engine constraints as used in dispatch, and actual recorded NEM dispatch.

The difference between the two cases is that, in the first case, dispatch is less impacted by congestion; and in the second case it is as actually impacted by congestion. So the second case is expected to have the higher operating costs for the year.

The difference is only in the variable costs, mainly fuel and variable operation and maintenance. No difference in capital costs will apply as the installed generation capacity is the same for both cases.

In both cases, renewables, including solar, wind and hydro, are assumed to have no short run marginal cost. As such, they do not contribute to the cost of congestion.

The analysis disaggregates full year results to two time periods to account for seasonal variation. These time periods are 1 December to 31 March 2017 and 1 April to 30 June 2017. The results of this analysis are discussed in more detail below and focus on areas where congestion was identified. For example, no significant indications of congestion were found in Queensland during the April to June time period. There was some indication of congestion in South Australia over the period of analysis. This is discussed as part of the New South Wales and Victoria results.

Results

The below charts compare the price at these nodes to their respective regional reference node. The charts show nodal prices that deviate from the regional reference node by more than five per cent (that is where the price is greater than five per cent higher or lower than the regional reference node). This is because price differences of less than

most faithful representation that AEMO can provide for forecasting, and AEMO uses them for its own forecasts.

54 This analysis has shown that the back-cast has captured the Basslink Interconnector flows accurately compared with history.

five per cent could be due to losses rather than congestion. Areas of potentially high congestion are represented by arrows on the charts. This indicates areas where nodal prices between two connected nodes are noticeably different.

Box 4.1 provides some detail on how to interpret this analysis.

Box 4.1 How to interpret this analysis of congestion

Consider a situation where two nodes are connected.

If there is no congestion (no constraints binding), they would be expected to have similar prices. However, there may be minimal differences between the two nodes due to line losses.

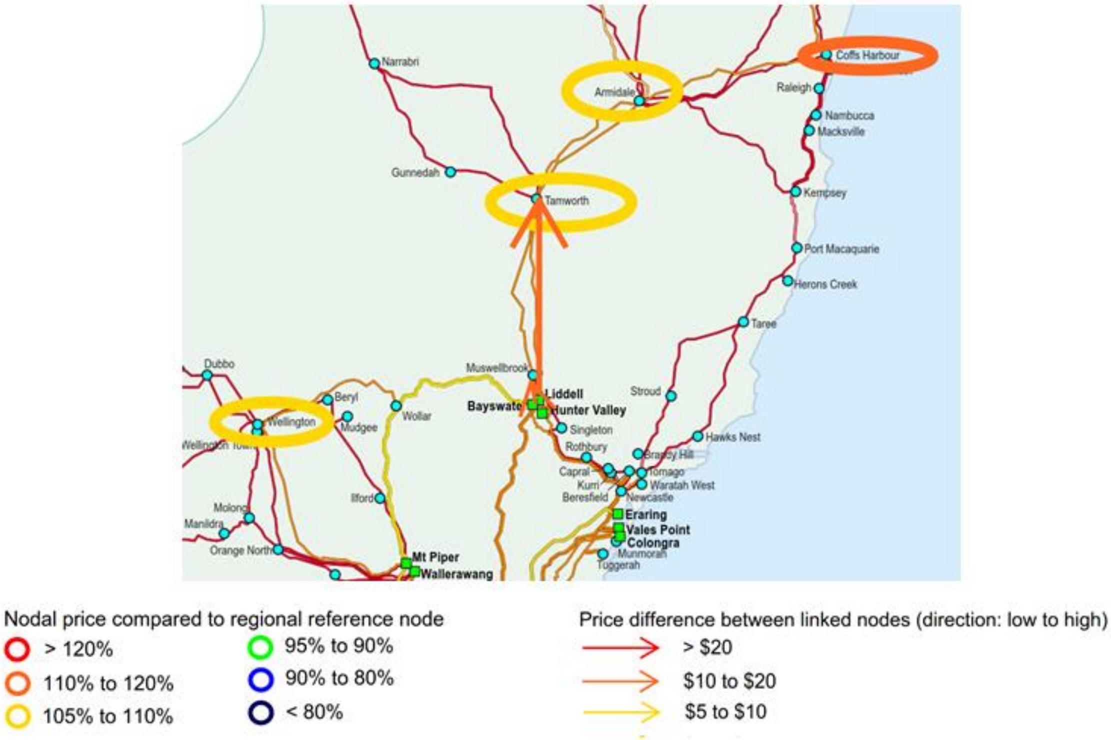
Alternatively, if prices are significantly different, this may indicate congestion between the cheaper node and its more expensive neighbour. This is because binding constraints (due to congestion) restricts the power flow between the two nodes which leads to this price separation.

If a cheap generator being dispatched at one of these nodes is impacted by a congested line prohibiting it to supply the neighbour node, then other more expensive generators may need to be dispatched at the neighbour node. The binding constraint provides high pricing at the neighbour node which gives a market signal for the more expensive generator to be dispatched.

Congestion in central New South Wales

The results of the congestion analysis for central New South Wales between December 2016 and March 2017 are shown in Figure 4.1. The results for April to June 2017 are shown in Figure 4.2.

Figure 4.1 **Congestion in central New South Wales December 2016 to March 2017**



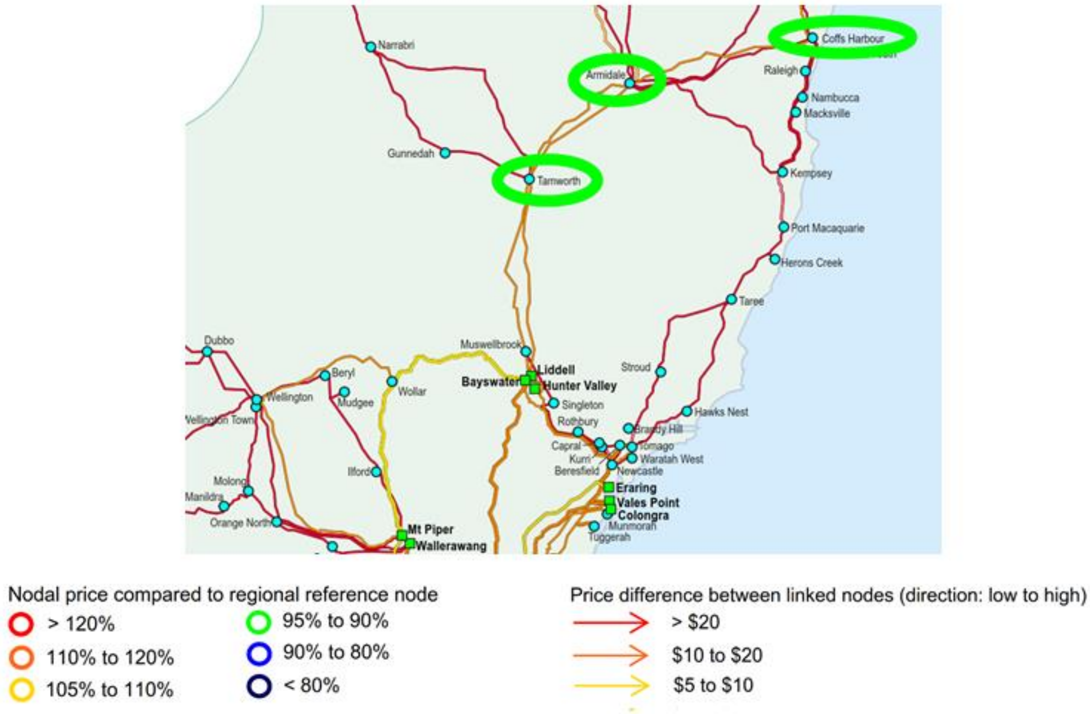
Source: EY analysis

Figure 4.1 shows that, during the summer months, prices are higher in nodes that are closer to the Queensland border. This is likely due to the additional demand requirements in Queensland during the hotter summer months.

As can be seen from the chart, nodal prices in areas of Northern New South Wales, such as Wellington, Tamworth, Armidale and Coffs Harbour, are relatively higher than the regional reference price. Figure 4.1 also shows that, on average, prices between the adjacent nodes of Bayswater and Muswellbrook, and also Liddell and Tamworth differ by up to $20, which may indicate congestion along these lines.[55]

55 Congestion and losses are the only key levers for differential pricing between nodes.

Figure 4.2 Congestion in Central New South Wales April - June 2017



Source: EY analysis

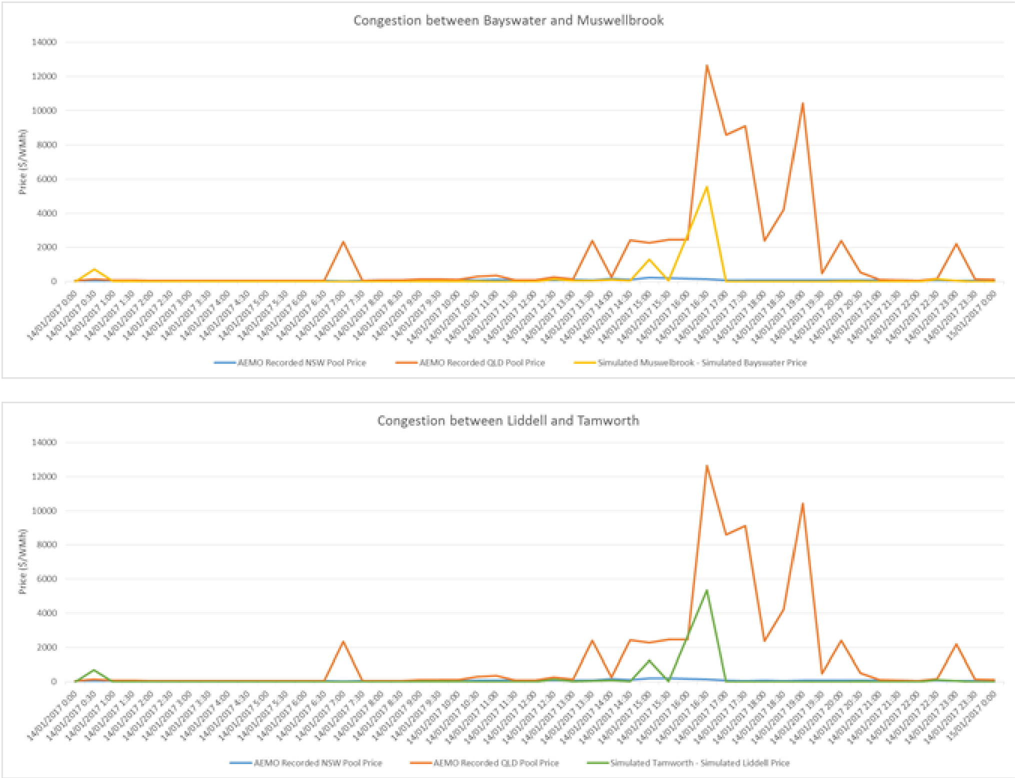
Figure 4.2 shows the results for the non-summer time period and shows that prices in the previously mentioned nodes of Bayswater and Muswellbrook, and also Liddell and Tamworth, are relatively low in the non-summer months, and no noticeable congestion is apparent.

An example of congestion in real time is given in Box 4.2 below.

Box 4.2 Example of congestion in Central New South Wales

On 14 January 2017 the regional price in Queensland approached the market price cap for several trading intervals (half- hourly periods). The Queensland regional reference price can be seen as the orange line on the below chart.

Figure 4.3 Congestion in Central New South Wales



Source: EY analysis

The charts above show that during these high price periods in Queensland, prices at some nodes in New South Wales separated from their regional reference price at Sydney West.

As a result of the high Queensland demand, often seen in summer months, more energy must be dispatched, which leads to a higher regional price.

This has a flow on effect to New South Wales, since energy from generators such as Bayswater and Liddell is dispatched to Queensland to meet this demand.

The increased flow causes line limits linking Bayswater to Muswellbrook and Liddell to Tamworth to be consistently reached from 3:40pm to 4:30pm. This congestion restricts the flow of energy out of Bayswater and Liddell in this direction.

The restricted dispatch increases the Muswellbrook and Tamworth nodal price which moves to a price between the Queensland and New South Wales reference nodes. This is shown on the yellow and green lines, respectively, on the above charts.

If this was a radial system, with only one path between Tamworth and Muswellbrook to Queensland then we would expect their prices to approximately match the Queensland regional price at this time, since the cost of energy would be the same.

However, there are alternative paths from other New South Wales nodes to the Tamworth and Muswellbrook nodes, and from Tamworth and Muswellbrook to

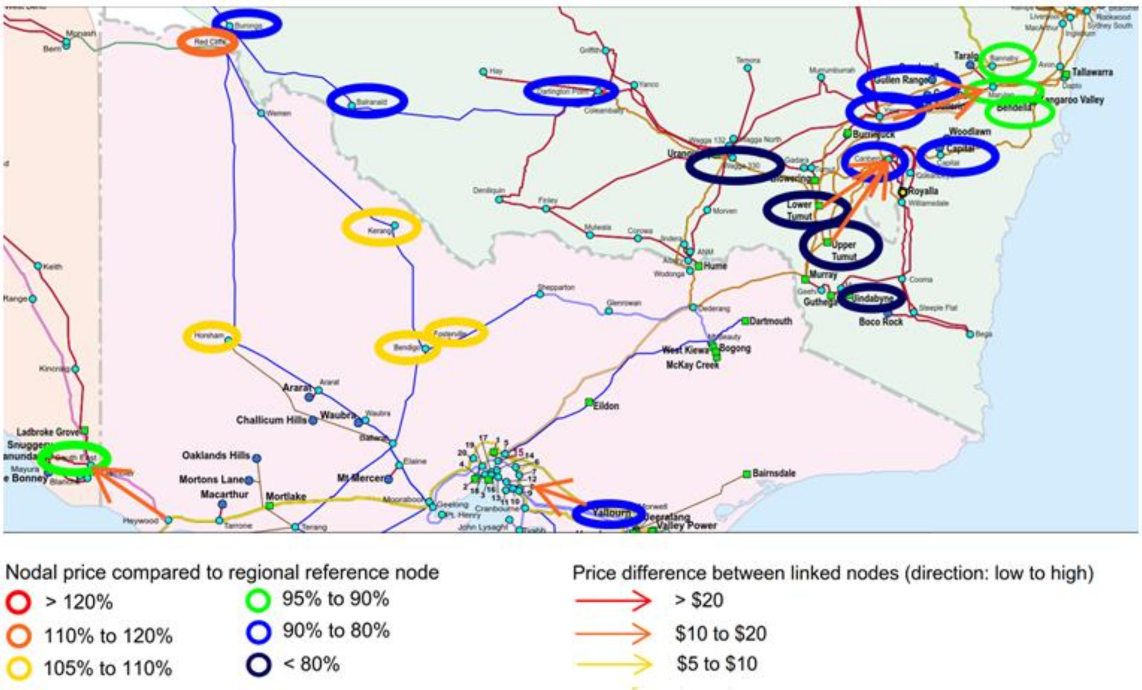
Queensland.

This is why the nodal prices at Tamworth and Muswellbrook are noticeably less than the Queensland regional reference node.

Congestion in New South Wales and Victoria

The results of the congestion analysis for New South Wales and Victoria between December 2016 and March 2017 are shown in Figure 4.4. The results for April to June 2017 are shown in Figure 4.5.

Figure 4.4 Congestion in New South Wales and Victoria December 2016 - March 2017



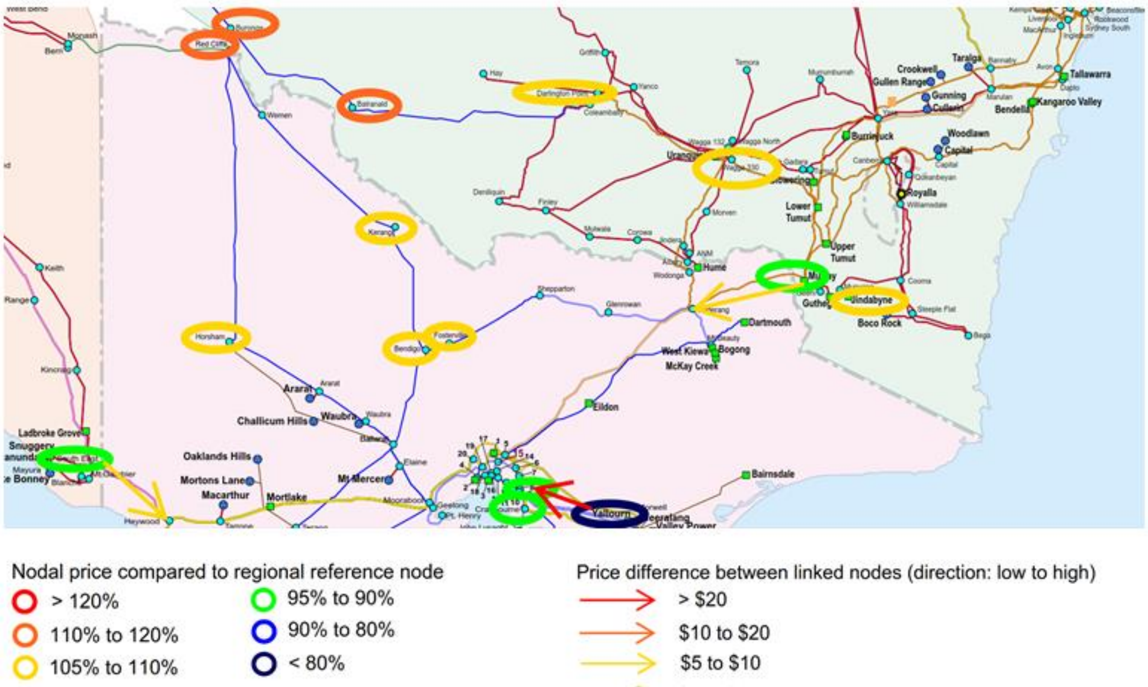
Source: EY analysis

The results from December 2016 to March 2017 show that nodal prices at Wagga, Lower Tumut, Upper Tumut and Jindabyne are low in comparison to the regional reference node.

While the Canberra node is less expensive than the (New South Wales) regional reference node, the price difference between it and both Upper and Lower Tumut reaches up to $20, indicating congestion.

Similar price differences are observed between Yass and Marulan in New South Wales, between Yallourn and Rowville in Victoria, and from Heywood in Victoria to South East South Australia.

Figure 4.5 Congestion in New South Wales and Victoria April - June 2017



Source: EY analysis

The results for April and June 2017 show that there appears to be large price differences between Yallourn and Rowville in Victoria, averaging above $20. In addition, limited congestion may be apparent from Murray in New South Wales to Dederang in Victoria.

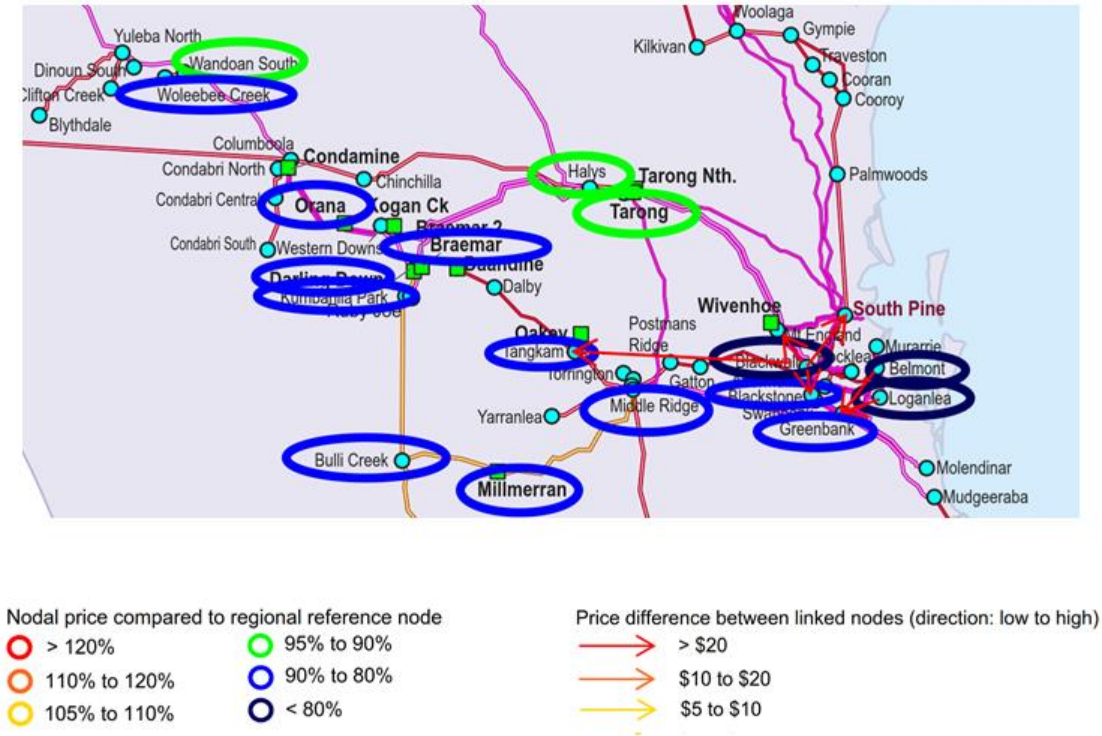
It can be noted that the possible congestion from South East in South Australia to Heywood in Victoria, has changed direction from what was observed in the previous period. This is likely due to the retirement of Hazelwood Power Station.

As noted above, no other areas of interest in South Australia were found in other time periods.

Congestion in Queensland

The results of the congestion analysis for Queensland between December 2016 and March 2017 are shown in Figure 4.6.

Figure 4.6 Congestion in Queensland December 2016 - March 2017



Source: EY analysis

The results show that the nodes at Blackwall, Belmont and Loganlea have low prices in comparison to the regional reference node. They are consistently averaging less than $20 cheaper than their adjacent nodes of South Pine, Mt England, Blackstone, Greenbank and Tangkam.

This result could indicate large levels of congestion, however, this may also be influenced by the line ratings used in the simulation.

As noted above, no significant indications of congestion were found in Queensland from April to June 2017.

Summary

In summary, it can be seen that there is limited congestion at the moment within the NEM. To the extent that congestion occurs, it is largely limited to between regions (i.e. inter-regional congestion), or is congestion occurring at the ends of the regions which is translating to congestion being observed on interconnectors. We understand that studies on upgrading interconnectors is currently underway by nearly all TNSPs in the NEM.

This analysis is also consistent with AEMO's analysis of congestion for the ISP. Specifically, the below figure (replicated from the ISP) highlights areas of network congestion during 2016-17 – it can be seen that the results are similar to the EY work.

Figure 4.7 AEMO analysis of congestion in the NEM

Figure 15 2016-17 transmission congestion heat map

Source: AEMO, Integrated System Plan

This figure shows that the bulk of network congestion in 2016-17 resulted from interconnector transfer limits, signalling there may be a need to analyse if there is value from upgrading interconnection. AEMO also note that these patterns of congestion could change in the future, depending on when and where generation resources connect. We understand that AEMO is seeking to undertake modelling showing *future* congestion patterns in the final ISP.

It also relevant to note some of the AER's observations regarding changes in transmission flows following the closure of Hazelwood in Victoria. Specifically the AER have observed that there have been notable changes to flows of electricity across the NEM in 2017. Victoria changed from being a net exporter of relatively cheap brown coal generation, to being a net importer. Flows from Queensland into NSW (and then through to Victoria) increased significantly as Queensland black coal generators increased output in 2017. South Australia also became a net exporter to Victoria, where previously it was a net importer. More generally, the interconnectors between the regions were constrained less often, resulting in greater price alignment between regions.[56]

Calculating the cost of congestion

56 See: https://www.aer.gov.au/system/files/AER%20electricity%20wholesale%20performance%20monitoring%20-%20Hazelwood%20advice%20-%20March%202018_0.PDF

In very simple terms, the cost of congestion estimated from this analysis is given from the equation **Cost of congestion = [Dispatch costs with constraints] - [Unconstrained dispatch costs]**.

The short-run marginal costs are derived from AEMO data from the 2016 NTNDP studies. Renewables are presumed to have a zero short-run marginal cost.

Cost of dispatch for units in the NEM in the presence of constraints are based on the actual dispatch of units from the 2016-17 financial year, which is available from AEMO data. The unconstrained cost of dispatch is calculated by removing N-1 contingency and short-term projected assessment of system adequacy (stability constraints from the simulated dispatch).

The following should be noted from the cost of congestion modelling work:

- The bidding strategy was not modified between the constrained and unconstrained model. It used the actual historical generator bids from the 2016-17 period:
  - In reality, in a competitive market, generators would be modifying their bids to better suit the conditions of an "unconstrained" network.
- For the unconstrained case, the notional interconnector/inter-regional limits were retained.
  - If the interconnectors were augmented, then these limits would be raised allowing further savings to be made.
- It was observed that in the "unconstrained" network gas generators (open cycle gas turbines) with high costs were dispatched less frequently throughout the year. Conversely, cheaper coal plants generated more energy throughout the year when compared to the "constrained" network.

The results show that the cost of congestion in 2016/17 was just under $17 million (or 0.36 per cent of total actual AEMO dispatch).[57] This is relatively small in the context of the NEM.

It should be noted that this analysis only considers historical congestion. It is anticipated that in the future, when a larger number of renewables (which have low short-run marginal costs) enter into the market, that the "cost" of congestion will be higher. Currently, AEMO has indicated that approximately 20 GW of asynchronous generating capacity has been proposed in the NEM.[58]

Methods to manage congestion

As noted earlier in this chapter there have been numerous reviews of congestion management. The Commission undertook the most recent of these reviews on congestion management and developed the optional firm access model as a way to address such issues. The model is described in further detail in Box 3.5 above. The Commission concluded that implementing optional firm access in 2015 would not

57 This result is given by taking the "constrained" dispatch costs of $4,671,652,600 form the "unconstrained" dispatch costs of $4,654,676,735, giving a cost of congestion of $16,975,865.

58 AEMO, Generator technical performance standards rule change request, p.9. See: https://www.aemc.gov.au/rule-changes/generator-technical-performance-standards

contribute to the National Electricity Objective at that time, but that if, in the future, congestion management or other such issues were to be more material, then optional firm access would be the best model to address these concerns and meet the National Electricity Objective.

The Commission is therefore interested in comments on the above analysis about the current state of congestion in the NEM, how this might change as the energy transformation referred to in chapter 2 occurs, and the potential ways in which this could be addressed.

4.2 Treatment of storage

Storage has the potential to touch the whole electricity sector, and provide a number of benefits. For example:

- Storage can allow consumers and businesses to respond to time of use tariffs and to reduce demand charges that reflect their impact on the network.
- Storage can reduce congestion on transmission and distribution networks, potentially shaving the peak demand that drives a lot of network augmentation.
- Storage can provide ancillary services like frequency control, voltage support and potentially even system restart services.
- Storage assets can substitute for generation, help to integrate intermittent renewable generation and allow trading between times of higher and lower wholesale electricity prices.

In relation to the coordination of generation and transmission investment, a number of stakeholders to the approach paper asked for further clarity on how transmission charging in relation to large-scale storage projects is treated in the current regulatory framework. As noted below, there is an increasing number of large-scale storage projects seeking to connect to the NEM. It is therefore important to consider how these projects fit within the regulatory framework, or whether changes are required.

4.2.1 Introduction

There are a number of large-scale storage facilities seeking to connect, or that have recently connected, to the NEM:

- Snowy Hydro's independent Board of Directors has approved to progress the Snowy 2.0 project from feasibility stage towards final investment decision and to undertake further work and project refinements[59]
- Tesla has connected a 100 MW battery near Jamestown in South Australia, which is part of South Australia's Energy Plan[60]
- the Victorian Government announced a $25 million energy storage initiative[61]

59 See: http://www.snowyhydro.com.au/our-scheme/snowy20/

60 See: https://www.tesla.com/en_AU/energy

61 See: https://www.energy.vic.gov.au/batteries-and-energy-storage

- several parties, including Energy Australia, are investigating the feasibility of pumped hydro in South Australia[62]
- the Queensland Government has announced a Powering Queensland Plan, which conducts a reverse auction for up to 400 MW of renewable energy capacity, including 100 MW of energy storage[63]

It is worth noting that AEMO has recently published a report on the operation of the Hornsdale Power Reserve (Tesla's "big battery") for the purposes of providing lessons learned for other interested parties. This battery provides range of services under commercial agreements between the South Australian Government, Tesla (the battery technology provider) and NEOEN (the operator of the Hornsdale Wind Farm). These services include energy arbitrage, reserve energy capacity, network loading control ancillary services and frequency control ancillary services (FCAS). This is the first time regulation FCAS have been provided in the NEM by any technology other than conventional synchronous generation. According to AEMO, the regulation FCAS provided by the Hornsdale Power Reserve is both rapid and precise, compared to the service typically provided by a conventional synchronous generation unit.[64]

These investments, and potential investments, have created increasing attention on the existing transmission framework arrangements and whether they are still fit for purpose.

Based on stakeholder feedback to the issues paper it appears that criticisms of the regulatory framework in relation to large-scale storage fall into two camps:

- whether or not storage devices need to pay charges for use of the transmission system, as loads currently do, rather than only pay shallow connection costs[65], as generators currently do.
- how hybrid facilities that combine storage with another generation source are treated for the purposes of registration.

These two aspects are considered in turn below.

However, the degree to which the operation of large-scale storage facilities aligns with current regulatory arrangements is being examined across multiple areas – not just in relation to the transmission frameworks. AEMO's report on the operation of the Hornsdale Power Reserve stated that "current FCAS market arrangements could be

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62 See: https://www.energyaustralia.com.au/about-us/energy-generation/energy-projects/pumped-hydro

63 See: https://www.business.qld.gov.au/industries/mining-energy-water/energy/renewable/renewables-400

64 See: https://www.aemo.com.au/-/media/Files/Media_Centre/2018/Initial-operation-of-the-Hornsdale-Power-Reserve.pdf

65 A shallow connection charge means that generators only pay for the direct costs of their connection to the transmission network. Any investment that is required to augment or reinforce the network to maintain a reliable supply to consumers as a result of this connection is paid for by the TNSP, and ultimately consumers.

modified to specifically recognise the rapid and accurate response capabilities of batteries, and therefore enhance their ability to earn income from providing them."[66]

4.2.2 Stakeholder submissions

Submissions to the approach paper generally noted that stakeholders would welcome some clarity on the treatment of batteries and storage.

The Public Interest Advocacy Centre commented that the categories of registration should be based on the behaviour of the facility, as seen by the network, and not the particular technology type. Pumped hydro and batteries should both be classified as storage under this proposal.[67]

In their submissions, the Public Interest Advocacy Centre, S&C Electric Company and the Australian Energy Council supported the creation of a separate registration category for storage.[68] The submission from Energy Networks Australia stated that there is a strong case for charging scheduled loads to a transmission network, on a negotiated transmission service basis, for a pure battery or a combined battery and generator connection configuration.[69]

Snowy Hydro suggested that energy used for pumping is primarily for the purpose of providing services such as energy, inertia, system strength and voltage support. These services are not provided by load. Hence services provided from pumped hydro generation are services associated with generation from a synchronous generator and therefore TUOS charges should not apply.[70]

4.2.3 Whether or not storage devices need to pay TUOS

As noted in chapter 2, currently in the NEM load pays TUOS, whereas generation does not. Storage generating units are both generation (i.e. they can export energy to the grid), but are also loads (i.e. they may, but do not necessarily, import energy from the grid to "recharge").[71]

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66 Ibid, p.8.

67 Public Interest Advocacy Centre, submission to approach paper, *Coordination of generation and transmission investment review*, 22 September 2017, p.3. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

68 Submissions to approach paper, *Coordination of generation and transmission investment review*: Public Interest Advocacy Centre, p.4, S&C Electric Company, p.2, and Australian Energy Council pp.1-2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

69 Energy Networks Australia, submission to approach paper, *Coordination of generation and transmission investment review*, 19 September, p.5.

70 Snowy Hydro Limited, submission to approach paper, Coordination of generation and transmission investment, 19 September 2017, p.2. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

71 An example of a battery that does not recharge from the grid is one that solely recharges from a connected generation source e.g. wind or solar farm.

The fact that load customers pay TUOS charges, and generators do not, likely requires consideration in the context of an increasing amount of large scale batteries seeking to connect in the NEM. For example, continuation of the current arrangements without clarity could create confusion and inappropriate incentives for proponents of large scale batteries.

AEMO recently released its guidance on interim arrangements for utility scale battery technology.[72] Consistent with the Commission's view, as expressed in its *Integration of storage* report,[73] AEMO considers that battery systems with an aggregate nameplate rating greater than or equal to 5MW, whether directly connected to the network or integrated behind the meter with new or existing generation, are able to be registered as both generators and market customers.[74] In addition, these parties must be registered as both scheduled generators and scheduled loads, meaning their charge and discharge will be set through AEMO's dispatch system.

Given this, some stakeholders have queried what this means for TUOS charging. AEMO's view, as set out in its guidance, is that intending participants wishing to connect large scale batteries should discuss the process for the negotiation of "use of system charges" with the relevant TNSP or DNSP consistent with principles set out in the NER, since each NSP determines "use of system" charges according to its own pricing methodology.

TUOS arrangements are within the purview of each local TNSP. The Commission understands that TNSPs are currently approaching the AER for decisions on how this can be treated, on a case by case basis. The Commission therefore considers there is a lack of clarity about how TUOS charging for storage is currently being treated. Ideally, consistent decisions on this would be undertaken across the NEM.

In terms of the Commission's view on whether batteries should pay TUOS or not, this is a complex issue. We consider that there are a number of considerations that would need to be taken into account in order to come to a conclusion on this:

- technological neutrality – chemical batteries (e.g. Tesla) should not be treated differently to pumped hydro
- incentives – for example, whether exempting scheduled loads with a battery from paying TUOS would create an incentive to become one of these (a scheduled load with a battery), since that would mean you would not pay TUOS
- whether scheduled loads face different reliability standards to other loads (which do pay TUOS in return for a certain level of reliability)
- whether there are any unintended consequences.

72 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/New-participants/Interim-arrangements-Utility-Scale-Battery-Technology

73 See: https://www.aemc.gov.au/markets-reviews-advice/integration-of-storage

74 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/New-participants/Interim-arrangements-Utility-Scale-Battery-Technology

The Commission is still considering these matters but welcomes views from stakeholders on the above. In particular, the Commission is interested in stakeholder views on what aspects of the existing NER may provide further clarity or guidance (or lack therefore) on the above.

4.2.4 Hybrid facilities

Hybrid generation facilities are becoming more and more common – participants are seeking to install batteries alongside other forms of generation, most commonly, wind and solar.

Chapter 2 of the NER sets out requirements for registration, which drives particular outcomes for these hybrid facilities. For example, assume a scenario where there is a hybrid generation of a 125 MW wind unit, a 25 MW battery and some auxiliary load. AEMO would require that this entity registers as a market customer and market generator for a single generating system, classifying the battery as a scheduled generating unit and scheduled load, and the wind farm as aggregated semi-scheduled generating units.

This becomes more complicated in dispatch since the semi-scheduled wind farm must use the AEMO run Australian Wind Energy Forecasting System to provide its availability. Conversely, the battery is scheduled, and so submits its own offers into the dispatch system. Therefore, this results in separate dispatch of:

- market scheduled generating unit (battery)
- market scheduled load (battery)
- market semi-scheduled generating unit (wind).

This configuration does not allow the entity to use the battery to smooth out its wind output.

AEMO is currently reviewing the registration categories set out in chapter 2 of the NER to make sure they are fit for purpose. The AEMC is involved in this process and looks forward to the progression of this piece of work. The Commission is interested in stakeholder views on how participants see these issues can be resolved through the existing framework. For example, is there a case for the existing registration categories to be collapsed or changed?

We note that the solution to both of these concerns with the current framework articulated in this section may be the same, for example, resolving the registration issue may also help resolve the question of whether or not TUOS should be paid.

5 Renewable Energy Zones

As noted at the end of chapter 3, the Finkel Review sought to address the challenge of coordinating transmission network planning and renewable generation investment, by focussing on the option of the development of REZs. It was envisaged that these "REZs" would facilitate the connection of new renewable generators to the transmission network.

AEMO is currently progressing the Finkel recommendation to more strategically plan the transmission grid through the ISP process. State governments and industry led projects are also exploring the implementation of zones devoted to renewable energy generation.

This chapter therefore considers the concept of REZs and the potential implications for the existing regulatory framework.

5.1 Background

The approach paper identified issues with the current transmission planning arrangements and noted that the concept of REZs or hubs was gaining traction with TNSPs and Distribution Network Service Providers (DNSPs). For example, TransGrid received funding from ARENA to investigate the feasibility of such hubs; and Powerlink and the Queensland Government have considered REZs through the Economic Development Queensland and Power North Queensland Plans. It went on to note that the Commission would consider REZs through this review.[75]

Since that time there has been other public consideration of these matters. For example:

- AEMO's consultation paper on the ISP notes that the first ISP in June 2018 will consider what makes a successful REZ, and if REZs are identified, how to develop them.
- TransGrid has recently identified the top three REZs in NSW and ACT to meet future need in the NEM.[76] TransGrid identified areas with: abundant renewable energy, existing network infrastructure with capacity to connect new generation and proximity to population centres where energy is consumed. Those seen to be the most feasible and cost effective are: Northern NSW, Southern NSW and South East NSW and ACT.
- In addition, the AER has recently commenced its review of the application guidelines for the regulatory investment tests for transmission and distribution. It specifically highlights in the issues paper for the review the need to provide further guidance in the RIT-T application guidelines in relation to the ISP, in particular, REZs.

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75 Approach paper, Coordination of generation and transmission investment, 22 August 2017, pp. 19-24. See: https://www.aemc.gov.au/sites/default/files/content/2385256c-2e77-46ae-933d-0cbc68d3787c/Approach-paper-for-publication-170822.pdf

76 See: https://www.transgrid.com.au/news-views/blog/Lists/Posts/Post.aspx?ID=205

5.1.1 Stakeholder submissions

Some of the stakeholder submissions to the approach paper addressed the option of REZs as a potential model for addressing challenges with transmission planning in a rapidly changing energy sector, identifying some of the perceived benefits of this approach in minimising costs to consumers, as well as some of the challenges that would need to be overcome. However, stakeholders provided limited "definitions" or substantive analysis of what a REZ is.

In its submission to the approach paper, TransGrid noted that the AEMC had understated the role of integrated planning in providing the basis for coordinating generation and transmission at least cost to consumers.[77] Explaining that the current framework results in incremental generation and transmission investment decisions, TransGrid stated that this approach will not lead to the least cost outcome for consumers in future given that the best locations for renewable energy are further from the existing network.[78] TransGrid contended that the lowest cost combined generation and transmission development option involves a strategic transmission investment that would service multiple generators into the future, and that generators are currently reluctant to participate in coordination processes which are allowed under the NER.[79] TransgGrid stated that "in a contestable market new entrant generators are often unwilling to share information or work with other new entrants to get the best network solution...furthermore, new entrant generators are at different stages of development so may not be in a position to negotiate transmission investment jointly with other generators."[80]

Similarly, in its submission, AusNet Services stated that new high renewable energy resource zones do not have the transmission capability for the scale of generation already planned. AusNet Services contends that the existing connection framework that involves a sequential connection application assessment approach designed for the infrequent connection of new large scale generators is ineffective and costly in the current circumstances.[81]

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77 TransGrid, submission to approach paper, Coordination of generation and transmission investment, 19 September 2017, p.4. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-t ransmi

78 Ibid.

79 TransGrid also highlighted that further thinking is required on the purpose, role and options for national planning, how costs should be recovered, how to evaluate these strategic investments, and the suitability of the current RIT-T process. TransGrid noted that consideration should be given to the practical barriers facing a planning or renewable energy zone model when developing the best theoretical approach to coordinate generation and transmission investment.

80 TransGrid, submission to approach paper, Coordination of generation and transmission investment, 19 September 2017, p.4. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-t ransmi

81 AusNet stated that a mechanism which contemplates network investment to meet the aggregate needs for numerous smaller generator connections should be part of the transmission expansion framework. AusNet Services, submission to approach paper, *Coordination of generation and transmission investment*, 19 September 2017, p.2. See:

S&C Electric Company also highlighted challenges with the current framework in its submission, noting that the only way to facilitate efficient investment in new network assets or upgraded assets is for better planning coordination between the generators and the transmission network service providers. The submission stated that a mechanism needs to be developed for the network-developer partnership in this scenario to ensure that investment is efficient and needed, otherwise any new network will become stranded. [82]

Energy Networks Australia noted that its members are receiving unprecedented numbers of connection requests for renewable generation and are looking for outcomes which allow for the connection of such generators that deliver the best outcomes for customers.[83] Energy Networks Australia stated its support for options that further examine the development of REZs, but that the establishment of 'slightly larger connection assets' does not necessarily address the critical main transmission capacity limitation issues for REZ.[84]

Examining the effectiveness of building out transmission capacity for addressing the NEM's current coordination challenges, AusNet Services noted that it is well known where transmission capacity upgrades are required to service identified renewable energy resource rich zones and proponents are already staking claims for access to these resources.[85]While these locations might already have been identified, AusNet Services stated that the market led approach is not effective in the circumstances of the transition to renewables, noting that the market cannot coordinate to achieve the necessary scale efficient augmentations necessary to connect significant new generation at the speed required.[86]

In contrast, while supportive of a process that efficiently connects REZs to the existing network, Snowy Hydro stated that "an integrated transmission plan which will allow market based solutions to arise is (its) preferred approach over a centrally-planned and

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https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

82 S&C Electric Company, submission to approach paper, Coordination of generation and transmission investment, 18 August 2017, p.4. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

83 Energy Networks Australia, submission to approach paper, Coordination of generation and transmission investment, 19 September 2017, p.6. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

84 Energy Networks Australia notes that these slightly larger connection assets may assist in more efficient radial connections to the network.

85 The submission therefore argued that locational price signals for transmission are not as important in these circumstances as it is not material to overall generation investment requirements. AusNet Services, submission to approach paper, Coordination of generation and transmission investment, 19 September 2017, p.5. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

86 Ibid, p.4.

mandated approach to transmission investment."[87] Similarly, Aurizon's submission noted that renewable energy hubs are generally facilitated by government intervention and care should be taken to ensure it does not distort investment and consideration is given to the key issues of reliability, security and the true cost of energy.[88]

Providing a consumer perspective, the Public Interest Advocacy Centre (PIAC) supported REZs as PIAC considered that they allow for efficiencies of scale which is beneficial for consumers through more efficient pricing while also incentivising the construction of renewable energy in a preferred location.[89] PIAC identified two areas that require careful consideration in order for REZs to be developed and effective in reducing energy prices for consumers. The first of these is the potential reluctance of generators to coordinate connection proposals due to concerns about the implications on confidentiality and competition in the market.[90] The second of these issues is which party is exposed to asset stranding risk, noting that the AEMC should consider how to most effectively allocate risk in the interest of achieving the most efficient long-term outcome for consumers.[91]

5.2 Integrated System Plan

As discussed in section 1.5.3, AEMO has commenced the development of the inaugural ISP that it states will deliver a strategic infrastructure development plan that can facilitate an orderly energy system transition under a range of scenarios, including REZs.

A significant portion of the ISP consultation paper discussed the concept of a REZ, what makes one successful, and how to identify and develop them. AEMO stated that a core component of developing the ISP was identifying the best locations to develop large-scale renewable generation.

Given the overlap between the ISP development process and some of the issues being considered in this review, the AEMC has been informally involved in the AEMO consultation process through participation in a workshop on REZs.

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87 Snowy Hydro Limited, submission to approach paper, Coordination of generation and transmission investment, 19 September 2017, p.3. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

88 Aurizon also stated that network planning should consider future technology flexibility, the generation mix in zones, and the consequential transmission network impacts to help ensure network capacity is not oversized at particular times and costs are minimised. Aurizon also suggested prioritising projects that can benefit from sunk infrastructure with the potential to provide multiple value streams including reducing costs, supporting generator investment, increasing network stability, reducing constraints and supporting demand. Aurizon, submission to approach paper, *Coordination of generation and transmission investment*, 19 September 2017, p.3. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

89 Public Interest Advocacy Centre, submission to approach paper, Coordination of generation and transmission investment, 22 September 2017, p.5. See: https://www.aemc.gov.au/markets-reviews-advice/reporting-on-drivers-of-change-that-impact-transmi

90 Ibid.

91 Ibid.

Initial insights from submissions to the ISP consultation paper that will inform the ISP scheduled to be published in June 2018 identified a number of regulatory issues associated with REZ development - see Box 5.1.

Box 5.1 Key messages from submissions

A number of parties (68) provided submissions to the ISP.

The common theme throughout these submissions was that the RIT-T process needs to be flexible enough to consider the benefits and economies of scale that can flow from strategic transmission investments. The extent to which submissions argued this point ranged from suggesting that the RIT-T process should not apply at all to investments stemming from the ISP, to identification of the RIT-T guidelines as an appropriate avenue through which to create flexibility in the regulatory approval process for strategic transmission investment.

Further making a case for examining the suitability of the RIT-T, the existence of the dispute process within the RIT-T was identified as a mechanism that works against consumers by allowing what would be a beneficial project to be derailed based on the interests of individual market participants.

The issue of sequencing was also raised as a practical challenge for the ISP – that is, under current indicative timeframes, the necessary development approvals for renewable energy generators would likely expire before a RIT-T was finalised to enable transmission development.

The need for the AER, which administers the RIT-T, and AEMO to liaise throughout the ISP development process to ensure a link is maintained for the coordination of approaches was also raised in submissions.

As the ISP consultation paper acknowledges, the Finkel Review is clear that "augmentations in line with the integrated grid plan would be evaluated through the RIT-T process or its successor."[92] It is also worth noting that while some stakeholders raised concerns with the RIT-T, the COAG Energy Council recently found the RIT-T to be a robust and appropriate mechanism to assess transmission network investments, which customers fund through TUOS charges as noted in chapter 3. It also found that the RIT-T provides an appropriate balance between rigour and timely investment decisions.

Therefore, a key question for stakeholders arising out of the ISP is how the RIT-T framework and the ISP, including REZs, will work together. Similar issues are being considered through the AER's review of the RIT-T application guidelines and it is important the work on this review, AEMO's work on the ISP and the AER's work on the RIT-T guidelines are considered together – we look forward to working together on these issues.

92 *Independent Review into the Future Security of the National Electricity Market: Blueprint or the Future*, June 2017, p.124.

5.3 What are renewable energy zones?

A key question for the Commission in considering the regulatory implications for REZs is 'what are REZs?' Flowing from this is what type of assets are these, what transmission services are provided as a result of these assets being constructed and what is the appropriate regulatory treatment of these assets.

In the ISP consultation paper, AEMO has defined 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."[93]

AEMO goes on to note that an efficiently located REZ can be identified by considering a range of factors, primarily: the quality of its renewable resources (wind or sun) and the cost of developing or augmenting transmission connections to transport the renewable generation produced in the REZ to consumers.

The AEMC does not consider it is immediately obvious what a REZ is, or should be defined as. There are a number of considerations that should be taken into account when developing a definition of a REZ.

For example, many regions with a high degree of renewable energy resources align with transmission development projects already under consideration, a point that was also made in the ISP.[94] In its submission to the ISP consultation paper, the Clean Energy Finance Corporation highlights that, to date, large-scale renewable energy projects in Australia have clustered around existing transmission networks, and have also gravitated towards higher quality energy resources.[95] So, defining REZs requires consideration of what size the "geographic area" is - is it an entire NEM region, or is it a smaller area, and if smaller than a region, how is that area defined for the purposes of identifying the boundaries to the REZ itself?

In addition there are other considerations that should be taken into account when defining REZs. For example, Tilt Renewable's submission to the ISP stated that planning permits and land access rights should also be taken into account – should these be reflected in the definition of the REZ?[96] These considerations are best known by the local TNSP, rather than a central body.

The Commission considers that there are a number of definitions of REZs, and that these can sit on a spectrum:

- at one extreme it may be the upfront provision of information to prospective connecting parties about where a good location to connect would be (i.e favourable resources, suitable land, available network capacity), which is similar to what TransGrid has identified through its renewable energy hubs

93 AEMO, Integrated System Plan Consultation, December 2017, p.29.

94 Ibid, p.34.

95 Clean Energy Finance Corporation, Submission to AEMO on the ISP consultation, March 2018, p.1. See: https://www.cefc.com.au/media/401878/aemo-integrated-system-plan-consultation-cefc-submission.pdf

96 Tilt Renewables, submission to the Integrated System Plan consultation paper, 1 March 2018, p.1.

- the other extreme would involve adopting similar arrangements to Texas where the Public Utility Commission of Texas identified areas with potential wind capacity resulting in the transmission infrastructure being built in those areas under a "build it and they will come" approach.

The Commission has developed four indicative definitions or types of REZ, which it considers are indicative of a range of options that would sit along this spectrum. These are outlined in Table 5.1, and explored further in the remainder of this chapter.

Table 5.1 REZ options

Option	**Option 1: Enhanced information provision**	**Option 2: Generator coordination**	**Option 3: TNSP speculation**	**Option 4: TNSP prescribed service**
Features	Enhanced AEMO and TNSP coordinated planning to signal (i.e provide information to market participants) on potential REZs for development by the market	Generators connecting in the same area work together to coordinate the connection process (similar to the SENE process)	TNSPs undertake speculative investment to build the REZ, i.e. the investment is not undertaken as a prescribed service	TNSPs build infrastructure in anticipation of generators connecting to a REZ, with this being constructed as a prescribed service
Who pays?	Same as now (generators if these are connection services; consumers via TNSPs if the REZ can be justified as a prescribed service)	Generators	TNSPs - if generators connect to these assets in the future then TNSPs would be allowed to roll the infrastructure into the regulated asset base and so consumers would pay for this	Since these are constructed as a prescribed service, consumers pay for this infrastructure
Who bears the risk?	Same as now (generators and consumers as per the above)	Generators	TNSPs - TNSPs would be rewarded for their increased risk if generators connect to these assets in future	Consumers - including facing the stranded asset risk
Implications for changes required to the existing framework	Minimal	Minimal - but larger coordination issues exist	Moderate	Substantial

Of particular interest to the AEMC in considering these options is what the implications are for the regulatory framework. The Commission must consider changes to the NER in line with the National Electricity Objective, i.e. changes should consider the long-term interests of consumers.

Reflecting on the development of the ISP to date, the AEMC notes that establishing a process for picking one zone for renewable energy investment over another by virtue of facilitating the development of the necessary transmission infrastructure risks creating inflexibility in the market by locking in a particular outcome. An approach to REZs that maintains flexibility in the system so that decisions made at one point in time under a particular set of circumstances can be adjusted to respond to market developments is likely to be more efficient over the long-term.

The current framework is set up to not impose excessive risks on consumers, such as those associated with anticipatory investment in network infrastructure. As Chapter 3 outlined, the RIT-T framework for prescribed transmission services is used to assess options for network augmentations or replacement and to protect customers, who bear the costs associated with these, from the risk that these investments or replacements are inefficient. Under a REZ framework there are a variety of parties who could bear the risks associated with REZs. This is considered in discussion of each of the options below.

5.4 Options 1 and 2: REZs under the existing framework

As discussed in chapter 3, the current transmission framework is defined by a number of key features. We have considered how options 1 and 2 above, can be facilitated in the existing framework.

Option 1 involves AEMO and TNSPs coordinating better to provide more information to market participants about where good places to connect would be. This could occur through better information being highlighted in the ISP and Annual Planning Reports, or, could also involve information being listed on the various network opportunity maps that the Australian Renewable Energy Agency has funded. Option 2 involves generators coordinating together themselves to construct and build REZs. Both of these options can occur under the existing regulatory framework and would be better facilitated following the *Transmission Connection and Planning Arrangements Rule*.

Box 5.2 Transmission connection arrangements in the NEM

The current transmission connection arrangements in the NEM allow parties to connect to the transmission network. This involves building transmission lines and substations that connect generators and major users to the network. In May 2017, the *Transmission Connection and Planning Arrangements Rule* (TCAPA Rule) introduced greater contestability for the design, construction and ownership of assets on the transmission network used for connection. There are two types of assets that provide the services required to connect a party to the shared transmission network – identified user shared assets and dedicated connection assets:

- **Identified user shared assets** broadly describe the collection of components that are used to connect a connecting party to the shared transmission network and which, once commissioned, form part of the shared transmission network, for example parts of a substation.

- **Dedicated connection assets** 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 the power line that connects parts of a substation to a generating system.

The TCAPA Rule clarified that all services provided for new dedicated connection assets, including design, construction, ownership, operation and maintenance, can be provided by any party on commercial terms. This is because the risks of inadequate design, construction and operation of those assets fall on these parties alone, and the shared network can be protected if appropriate action is taken, such as isolating the connection. The Primary TNSP may, but is not obliged to, provide these services. If it does, the services provided by the Primary TNSP are non-regulated transmission services, paid for by the connecting generator.

Under the TCAPA Rule, certain development aspects of identified user shared assets are contestable and others are non-contestable. Where the services are non-contestable, they are provided by the Primary TNSP exclusively and are negotiated transmission services, paid for by the connecting generator.

As such, under the existing connection framework (as amended by the TCAPA Rule), the services associated with connection to the transmission framework by a generator are either non-regulated transmission services or negotiated transmission services paid for by the connecting generator.

Therefore, under the current framework, including as amended by the TCAPA Rule, there are no prescribed transmission services associated with the connection of a generator to the transmission network.

5.4.1 Option 1

A key question for considering a REZ in the context of the existing framework is whether the assets associated with this are providing a connection service, or whether they are part of the shared transmission network and are providing a prescribed service (or, potentially a combination of both).

Under the transmission framework, as amended by the TCAPA Rule from 1 July 2018, the assets associated with REZs would most likely be considered dedicated connection assets and identified user shared assets that are required to connect a group of generators to the shared transmission network. In other words, these assets would be considered connection assets, providing connection services, and so would be paid for by the connecting party/ies (i.e. generators).

The amendments to the framework effective 1 July 2018 improve transparency, contestability and clarity in the connection framework with the aim of making it easier and cheaper for generators to connect to the network - and so to develop REZs. Generators will be able to contestably construct their connection assets. Many stakeholders suggested that contestable construction would enable connecting parties to connect faster and cheaper than under the existing connection process.

It is therefore easy to see how a definition of a REZ as under option 1 could be easily accommodated under the current regulatory framework.

If this augmentation of the transmission network is not provided as a contestable service or negotiated transmission service paid for by the generators in the REZ, then the assumption is that, instead, it would need to be provided by the TNSP as a prescribed transmission service. However, it is unclear under the current framework how the provision of such a service would meet the definitions of a prescribed transmission service.

Furthermore, the costs of providing prescribed transmission services are recovered from transmission network users (which does not include generators) through TUOS charges, with the revenues that a TNSP can recover for these services regulated by the AER. Such an approach would not be supported by the current framework since to do so would require consumers to bear the risk of potentially inefficient investment or stranded assets built to service the connection, or potential connection, of new generators.

There may need to be minor changes to the transmission planning arrangements under option 1. Currently, the transmission planning arrangements in the NEM involves an ongoing feedback loop of information with AEMO publishing the NTNDP and each TNSP publishing its transmission annual planning report which uses the NTNDP as an input. The national assessment that AEMO provides is a vision of the transmission network using a range of scenarios to examine the efficient development of the national transmission grid.[97]

The TNSP planning process then essentially localises the projected investments, with specific augmentations driven by the TNSPs' obligation to meet the relevant jurisdictional reliability standard. Generator requests to connect to the network are handled on an ad-hoc basis, and any transmission network investments must demonstrate that they benefit consumers via the RIT-T process.

In order to better facilitate option 1, TNSPs and AEMO could use these documents to set out more information to prospective connecting parties about where a good location to connect would be (i.e favourable resources, available land, spare network capacity).

As noted above it is difficult to see how an asset built by a TNSP for the purpose of servicing a REZ would be an asset providing a prescribed transmission service under the current arrangements. Therefore, it is unlikely that they would fall within scope of TNSP planning and so may require NER changes in order to better facilitate this.

However, there are several examples that the Commission is aware of where a prescribed transmission service could be considered relevant to the development of a REZ. One such example is the current RIT-T process that ElectraNet is undertaking for transmission investment on the Eyre Peninsula in South Australia which is examining

97 The Australian Energy Council (AEC) submission to the ISP concluded that AEMO's role in developing the ISP should not extend beyond its existing role and powers. These are outlined in the AEC's submission as AEMO providing "recommendations to transmission providers to consider certain extensions of a national character that are likely to pass the well understood and prudent economic cost/benefit analysis of the existing RIT-T." AEC, Submission to the ISP, 9 February 2018, p.2.

whether building new higher capacity transmission lines, including over more diverse paths, may result in greater expected net benefits to customers over the long-term given potential future developments in the region. This project is outlined in Box 5.3. The Commission is interested in stakeholder views on the relevance (or not) of this for REZs.

Box 5.3 ElectraNet: Eyre Peninsula electricity supply options[98]

ElectraNet has been actively exploring options to improve the reliability of supply to Port Lincoln, including options to replace or upgrade the transmission lines serving the lower Eyre Peninsula.

ElectraNet's most recent assessment of the line condition indicates that components of the line are nearing the end of their functional life and will require replacement in the next few years. To enable this work, the TNSP has included in its 2018-19 to 2022-23 revenue proposal to the AER an allowance for the replacement of major transmission line components on the Eyre Peninsula . Alternatively, the full replacement of the line (for example as a double circuit line) may be more cost effective and deliver greater benefits to Eyre Peninsula customers through potentially improving supply reliability and capturing other market benefits.

To take this forward, ElectraNet is undertaking the RIT-T, which will assess the costs and benefits of alternative network and non-network solutions. In April 2017, five credible options to upgrade the power supply were released publically and since then ElectraNet has undertaken detailed investigations into which will best meet the needs of the Eyre Peninsula and South Australian electricity customers.

Following these investigations and assistance from various project stakeholders, ElectraNet argues that the option that delivers the greatest benefits to the community has been identified. The option includes the construction of a new double-circuit 275 kV power line between Cultana and Yadnarie and a new 132 kV double-circuit power line between Yadnarie and Port Lincoln. ElectraNet stated that this option will provide the Eyre Peninsula with a reliable power supply and the ability to meet *future electricity demands and generation capacity* from proposed mining ventures and wind farms respectively.

A final ruling by the AER on the outcome of the RIT-T process is expected by mid-2018. If the option is approved, ElectraNet states that it is expected to cost approximately $300 million and would be operational by the end of 2020.

98 ElectraNet, Eyre Peninsula electricity supply options. See:https://www.electranet.com.au/projects/eyre-peninsula-electricity-supply-options/

5.4.2 Option 2

Option 2 builds on option 1, i.e. we expect that the increased information provision under option 1 would also occur under option 2.

This option is similar to the existing Scale Efficient Network Extension (SENE) framework. The SENE Rule made by the AEMC in 2011 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. 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.

In addition, the new connections framework may also better facilitate the creation of REZs by generators themselves (e.g. similar to the existing SENE framework). To support this, the new arrangements explicitly allow for the adjustment of the price for negotiated transmission services over time to the extent that assets used to provide the service are subsequently used to provide services to another person. As such, the provision of cost sharing arrangements between parties and clarity about how costs can be shared between multiple parties connecting at the same identified user shared asset or dedicated connection asset may help facilitate the development of REZs within this framework.

However, further (minor) changes to the regulatory framework may be required under option 2 since generators may not wish to "team up" with competitors to develop a REZ - even knowing that they could receive cheaper connection costs by virtue of doing this. Further, TNSPs are required to keep connection applications confidential and so prospective generators may not know about other generators wanting to connect in the same area.

Generators also may not want to take on the risk associated with funding infrastructure for other generators. This may be exacerbated due to the current open access regime, which is discussed in further detail below. However, it is also worth noting that the new arrangements under the TCAPA Rule provide for persons owning, operating or controlling large dedicated connection assets to have access policies, approved by the AER, which provide a framework for applicants to obtain access to services provided by means of those assets, therefore, enabling generators to better coordinate connections and fully utilise existing assets.

The AEMC notes that the SENE framework has not been used to date. Stakeholders have identified similar concerns to above as to why they have not been used. For example, key implementation issues include reluctance on the part of investors to take on the risk of asset stranding that could occur if projected generator connections did not happen, and generators being unwilling to share commercially sensitive information with each other in order to facilitate coordinated connections.

An alternative would be to make it easier for generators to bear the risks associated with the REZ. As noted above, generators could bear the risks of this under the current framework but are unwilling too. Given this it is important to realise that regulation cannot fix all challenges that may arise through the implementation of REZs. For example, the incentive for generators to commit to a cooperative framework that will lead to a better financial project outcome for themselves may be clouded by larger strategic commercial considerations, such as being involved in a process that provides competitors with lower connection costs than they would otherwise pay. Alternatively, they simply may not want to accept the risks.[99]

5.5 Options 3 and 4: Changes to the current framework

If the above arrangements for REZs are not considered appropriate, then in order to facilitate more REZs, more substantial changes to the existing frameworks would be required. For example, the REZ model being explored through the ISP suggests that oversizing of transmission infrastructure and the associated anticipatory investment is required to achieve economies of scale. The planning and risk allocation implications of this approach differ significantly from the current framework.[100]

Both of these options would require more significant changes to the current regulatory framework and are discussed in this section.

Under both these approaches the definition of prescribed transmission services, would need to change, as well as a number of other definitions in the NER.

5.5.1 Option 3

Option 3 involves TNSPs making speculative investments using their own profits, not regulated revenue, to facilitate a REZ i.e. shareholders of TNSPs bear the risks associated with a REZ. However, if generators do ending up connecting to the REZ, then the assets would be rolled into the TNSP’s asset base and they would receive a regulatory allowance for these assets.[101]

This option can be considered similar to the mechanism for speculative investment set out in the National Gas Rules (NGR). In the NGR, there is a mechanism that allows full regulation pipelines to undertake speculative investments and to include this expenditure in the capital base when circumstances change. The rate of return to be applied to such a speculative investment has recently been considered by the Commission to ensure it appropriately aligns with the particular circumstances of the project. This is discussed in more detail in Box 5.4.

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99 This challenge is highlighted by TransGrid as a commercial hurdle to be overcome in the development of coordinated renewable energy investment. See: Renewable Energy Hub Knowledge Sharing Report, 2 June 2016, Version 23.0, p.7.

100 The AEC submission to the ISP stated that AEMO's approach to the ISP needs to be guided by the framework in the current NER and National Electricity Objective, noting that the regulatory framework's "stability provides confidence for investors in the competitive sector to anticipate in what circumstances monopoly network assets will be developed." AEC, Submission to the ISP, 9 February 2018, p.1.

101 Consideration would need to be given to how this process for including these assets in the RAB would work in practice.

Box 5.4 Speculative capital expenditure in gas

The National Gas Rules (NGR) allow full regulation gas pipelines to create speculative capital expenditure accounts.[102]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 due to changes in volumes or service charges.

As part of the assessment of an access arrangement, this non-conforming speculative capital investment can be allocated to a speculative capital expenditure account. If, as a result of changes to volumes or service charges, the expenditure would become approved, the relevant portion of the speculative capital expenditure account (including a return that is approved by the regulator) can be rolled into the capital base at the commencement of the next access arrangement period. This would then allow the capital cost to be recovered through reference tariffs in the future.

This rule has not been utilised since the NGR commenced due to the uncertainty of the rate of return that would apply in this situation. The Commission has examined the issue of speculative investments as part of the *Review into the scope of economic regulation applied to covered pipelines*.[103] In the draft report of this review, the Commission recommended clarifying "the rate of return to be applied to a speculative capital investment under rule 84 of the NGR is, at a minimum, the return implicit in the reference tariff but that this could be adjusted upwards if the regulator deemed it was appropriate having regard to the circumstances of the particular investment."[104]

5.5.2 Option 4

Option 4 involves TNSPs making speculative investments on the behalf of consumers to facilitate a REZ, and then consumers paying the costs for these. Regardless of whether generators do or do not end up connecting, the assets would be rolled into the TNSP’s asset base, and they would receive a regulatory allowance for these assets paid for by consumers. One question that would need to be considered under this option is whether the capital expenditure would be subject to assessment by the AER or all assumed to be efficient and allowed to be rolled in to the regulatory asset base.

Under option 4 amendments to the NER would need to be made to make it clear that certain assets built for the REZ provide prescribed transmission services, and so would form part of the shared transmission network and be paid for by consumers. The consequences of this are set out below.

102 Rule 84 of the NGR.

103 See: https://www.aemc.gov.au/markets-reviews-advice/review-into-the-scope-of-economic-regulation-appli

104 Draft report of the *Review into the scope of economic regulation applied to covered pipelines*, 27 February 2018, p.106.

Similar to option 3, it will be important to gain greater clarity about what assets are “connection” assets to be paid for by generators and what assets form part of the “shared transmission network" to be paid for by TNSPs (consumers).

The argument in favour of REZs from an efficiency point of view is that it creates economies of scale, noting however, that if the full scale is never utilised, the economies will not be achieved. The REZ model requires a planning process to identify areas with sufficient energy resources to justify transmission system expansion and reinforcement to these zones before generation has committed to locate in the area.

Deviating from the ad-hoc connection of renewable generators that currently occurs, a REZ model suggests a shift to a more coordinated planning process ("build it and they will come") to determine the zones and decide under what circumstances the investment in generation and transmission infrastructure to those zones can take place. Planning for transmission infrastructure to the zones, or shared connection assets within a zone, would be conducted with reference to a large number of potential or actual generation projects considered simultaneously, rather than on a sequential, individual basis as is the current process. While not a necessary feature of all REZs, planning may at times need to occur in advance of some generator commitments. This is a change to the way transmission planning is currently undertaken since it involves planning decisions being undertaken on a forecast of the future, that may or may not turn out to be true.

A key objective of the planning process is to bridge the gap between the lead time for substantial transmission investments and shorter development times for technologies such as wind and solar generation. While REZ-type approaches are typically focussed on the timely and efficient connection of renewable generation sources, the new zones do not necessarily need to be restricted to these forms of supply. Usage of the new infrastructure by non-renewable forms of generation and load could also be considered in the planning process. Both the planning to identify the zones and the transmission requirements need to be undertaken at the same time to identify the best locations for the zones to be established, for example, taking factors such as proximity to the existing transmission system into account.

A REZ approach that involves the development of the transmission network to influence where new generators should locate is significantly different to the current practice where a new generator connection request drives incremental augmentation of the transmission network. If a transmission investment that will deliver a prescribed transmission service is made on the basis of an expectation that new generation will locate in a particular area of the NEM, consumers will bear the risk that this expectation is wrong and the asset becomes stranded. To facilitate this would require changes to the existing regulatory framework.

The purpose of the RIT-T is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the NEM.[105] Making a case for the value of strategic long-term investments that coordinate both generation and transmission investment through a rigorous planning and review process presents a significant change to the way TNSPs

105 Rule 5.16.1 of the NER.

have approached justifying network augmentation. The existing RIT-T process does not exclude REZs if the criteria for investment can be met through demonstrating the benefits that would be provided to consumers through a coordinated investment process. An assessment of such an investment should balance both the potential for efficiency to be maximised against the appropriate allocation of the costs and risks of network investments.

The AER is currently considering how the ISP could be aligned with the existing RIT-T process. In particular, the RIT-T application guidelines are likely to consider how the RIT-T can be used to deliver strategic transmission projects. These issues are also being considered by industry, for example, in TransGrid's submission to the ISP, it proposed some suggestions for how the RIT-T could be supplemented to better accommodate REZs.[106]

If it was considered appropriate that consumers should bear the risks, to mitigate risks of consumer exposure to the potential costs of stranded assets, and thus make a case for transmission augmentation in renewable energy rich regions, a number of requirements could be built in to the planning and decision-making processes for REZs. However, it may also not be appropriate for consumers to bear the risks. For example, consider geothermal capacity: in 2008 an Australian Geothermal Energy Association report predicted that geothermal could potentially produce 2,200 MW of thermal baseload by 2020.[107] Obviously none of this eventuated. If REZs could be built as prescribed services in 2008 (requiring substantial transmission upgrades out into the middle of Australia where these resources are found) there would now likely be stranded assets, being paid for by consumers.

A staged planning process with extensive stakeholder engagement would create opportunities for input from key parties. For example, multiple potential zones could be identified, then narrowed down to a final selection taking into account factors such as the level of generator commitment. Effective stakeholder engagement and feedback throughout the planning process is likely to be a critical factor in successful REZ development.

Addressing the risk of stranded assets through a requirement for generator commitment would enhance confidence that the transmission network being built would be used. Commitments could include some form of financial commitment, or evidence of substantial development progress, such as a signed connection agreement. A defined threshold of generator commitment could be required before investment in a zone could take place (for example, 50 per cent of the planned REZ capacity).

A further option for managing risk could be the implementation of staged investment in the zones, with the release of additional zones or portions of zones after uptake of existing zones has reached a certain level. Thought would also need to be given to the sequencing of the zones, for example, whether a particular sequence is more or less

106 TransGrid, Integrated System Plan Submission, February 2018.

107 See: https://www.reuters.com/article/us-australia-power-geothermal/australian-hot-rocks-offer-26000-yrs-of-power-idUSSYD30694020080820

robust to changes in circumstances or a required course correction due to incorrect initial assumptions.

5.6 REZs and access

It is also worth considering whether the existing open access regime may need to change in the context of REZs. As discussed above, the building of a REZ would involve transmission infrastructure (either connection or prescribed transmission services) being built. Under an open access framework, other generators that were not part of the REZ could subsequently connect in or near the REZ, with this resulting in the generation that is part of the REZ being constrained off and effectively "stranded," with consumers bearing the costs associated with that.

The Commission is interested in stakeholder views on this point. That is, whether this is a concern - that renewable energy hubs can be considered as providing "local" supply (i.e. to a local load), and so this issue may not be material since the generation would not have to access the market deeper in the network. If such an issue is considered material, then options to facilitate access (such as optional firm access) may also need to be considered, with such options representing a more substantial change to current regulatory framework.

TransGrid noted in its submission to the ISP that the open access regime for generator connections in the NEM could be a barrier to developing large scale energy zones, since over time this could diminish the consumer benefits of connecting the high quality resources.[108]

It is also worth thinking through the risks for generators within the REZ that if a REZ of relatively large size is connected to the rest of the shared network via limited transmission infrastructure (e.g. a single or one double circuit transmission line), even if only initially, that not only is there a finite amount of capacity until additional infrastructure is built, but there is also an appreciable risk of limited redundancy or route diversity which may create outage or dispatch risks for the generator(s).

5.7 Conclusion

As discussed above there a range of potential definitions of REZs. The Commission is interested in stakeholder feedback on these different options.

A key consideration that should be taken into account when determining arrangements for REZs is who is best placed to manage the risk - the above section sets out some considerations on this point. If the risk is allocated accordingly, outcomes should be least cost. The Commission does not necessarily think it is appropriate for consumers to bear the costs associated with centralised resources (e.g. large-scale generation and transmission). This risk is likely to be better placed with the generation and transmission businesses themselves.[109]

108 TransGrid, submission to the Integrated System Plan consultation paper, February 2018, p.11.

109 The risk is better places with the TNSP as a negotiated service rather than as part of its prescribed service revenue.

Under the current regulatory framework, if the connection of new generators in a REZ requires investment in transmission infrastructure that will provide a prescribed transmission service, the benefit that this will provide to consumers must be demonstrated. The AEMC would welcome stakeholder comment on options for reducing risks to protect consumers in the development of REZs.

REZs are designed to overcome the "chicken and egg" phenomenon that currently exists in relation to transmission and generation investment. New generation projects typically want to know what level of transmission access they will receive, but firm access or proactive transmission expansion is not supported under the current framework. There may be other ways to overcome this problem in future.[110]

5.8 Potential other options - clustering approach

This section seeks to explore another option to address the challenge of coordinating generation and transmission planning identified at the beginning of this chapter given its similarity to the REZ model, and the fact that it would necessitate limited changes to the current transmission framework. A key issue that has arisen in recent years is the volume of connection applications that have been received for new generation. This is exacerbated by the speed at which some supply-side resources, notably wind, solar and battery storage, can be developed, compared to thermal or hydroelectric generation plants which involve considerably longer lead times. Both TNSPs and AEMO can face challenges in planning to efficiently accommodate new developments with the presence of uncertainty around the proportion of new connection applications that will proceed to completion.

A clustering or group consideration of connections approach would allow TNSPs to coordinate generator connections based on what delivers the most efficient outcome. 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.

Within this broad model are a range of design choices around the length of the season or the size of the geographic area, the circumstances where connections can be excluded from the cluster planning process, mechanisms to manage spurious or speculative connection requests, and other factors. These choices create potential trade-offs around the additional information and discretion available to TNSPs to plan their network efficiently, and risks of delays or uncertainty for generators.

A clustering model could also provide a degree of discretion to TNSPs in terms of being able to delay or refuse a connection if it does not fit within an efficient augmentation

110 For example, the optional firm access model that was discussed in Box 4.3 would have generators fund and guide the development of new transmission.

plan. For example, the plan produced by the TNSP could incorporate a prioritisation of connections. One potential advantage of allowing such discretion could be to provide an additional locational signal to generators of the costs they would place on the system at different points, although the value of this may be questionable if generators are required to go through a long process in order to gain visibility of these costs and the timing of their connection. On the other hand, there may be significant disadvantages, including uncertainty for generators that may create a barrier for new entrants and whether the TNSP has the appropriate information and incentives to make such judgements.

The clustering approach does not deviate from the current design of the transmission framework to the extent that the REZ model does. A greater planning role is afforded to TNSPs under this approach than currently exists, where rather than considering generator connection applications on an ad-hoc basis, TNSPs would coordinate connections to optimise efficient investment in transmission infrastructure.

This clustering model provides a practical way to approach the issues that REZs seek to address. The AEMC would welcome stakeholder comment on the clustering approach as an option for coordinating renewable generation and transmission investment. The AEMC would also welcome stakeholder input on whether there are other options that might achieve this outcome.

6 Conclusion and next steps

A final report for this review is due in mid-2018. The Commission will coordinate this work with that being done by the other market bodies, specifically AEMO through the ISP and the AER through its consideration of the RIT application guidelines. The Commission has set out its preliminary conclusions on three potential issues with the current transmission framework: congestion, the treatment of storage and the model of REZs.

Congestion in the NEM

The issue of congestion management in the NEM has been the subject of ongoing debate since the establishment of the NEM in 1998. As there are no firm access rights for generators in the NEM, there is no guarantee that they can export all of their output to the system at any given time. Since the start of the NEM, there have been twelve major reports and reviews dealing with various aspects of congestion management and generator access.

There is limited congestion in the NEM at the moment – the congestion largely occurs between regions (that is, "inter-regionally"). However, there is now over 45,000 MW of proposed generation across the NEM.[111]While all of this generation may not eventuate, to the extent it does, there could potentially be significant congestion in the future.

The Commission is therefore interested in comments on the analysis about the current state of congestion in the NEM, how this might change as the energy transformation occurs, and the potential ways in which this could be addressed.

Treatment of storage

Some of the proposed new generation entering the market includes large-scale, utility storage. One notable example has already connected – Tesla's battery at Hornsdale Wind Farm – showing that the regulatory framework does not have any barriers to the connection of storage.

However, more storage facilities wish to connect, and the experience of a few storage connections that have occurred to date has revealed some potential areas of the regulatory framework that may need to be adjusted to better facilitate large-scale storage connections. We are interested in stakeholder views on whether there are any additional issues that we should consider.

Renewable Energy Zones

The Finkel Review sought to address the challenge of coordinating transmission network planning and renewable generation investment, specifically focussing on the option of the development of REZs to facilitate the connection of new renewable generators to the transmission network. In progressing to stage 2 of this review, the Commission identified a spectrum of options to coordinate generation and transmission investment in the NEM, however we have focussed on REZs in this interim report given the Finkel Review sought to progress consideration of this model.

111 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

A key question for the Commission is what exactly is a REZ? Under some definitions of REZs, they can easily be accommodated in the existing regulatory framework; while other options for the design of REZs would require changes. We welcome stakeholder views on these matters.