REVIEW

Australian Energy Market Commission

APPROACH PAPER

Coordination of generation and transmission investment

22 August 2017

Submissions due 19 September 2017. Reference: EPR0052

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 requested that the Australian Energy Market Commission (AEMC or Commission) implement a biennial reporting regime on a set of drivers that could impact on future transmission and generation investment. This work should 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.

This approach paper commences the start of stage 2 for the Review, as laid out in the terms of reference. In order to more accurately reflect the subject matter considered in this stage 2 of the Review the title has been changed from *Reporting on drivers of change that impact transmission frameworks* to *Coordination of generation and transmission investment*.

The stage 1 final report was published in July 2017, and concluded that, based on the conditions identified in the terms of reference for this Review, as well as other developments in the energy market, the reporting should progress to stage 2. The criteria used to decide that the Review should progress to stage 2 were:

- the drivers of change that impact transmission and generation investment have changed since October 2015
- there is likely to be large amounts of transmission and generation investment in the near to medium term
- future expected investment in uncertain in its location or technology.

This paper provides further detail on the issues that will be examined in more detail in the second stage of this Review. Specifically, it provides detail on the current arrangements for transmission and generation investment in the NEM and the potential issues associated with these arrangements. Potential options to address these issues are also identified.

This paper is designed to start the process for stage 2 and to define the issues that will be examined in more detail as the Review progresses. The paper aims to provide greater detail on the main issues that have been identified with respect to the coordination of transmission and generation investment and to provide an overview of some of the options to ameliorate these issues. The options identified in this paper are not an exhaustive list of potential changes that could be made to the regulatory framework and we welcome stakeholder feedback on the analysis and options presented in this approach paper.

We invite stakeholders to provide submissions on this approach paper, which will inform the next stage of this Review. Stakeholders wishing to meet with the AEMC should contact Therese Grace at 02 8296 7842 or therese.grace@aemc.gov.au. Submissions close on 19 September 2017.

An options paper will be published in November 2017, which will narrow down the various options under consideration and provide more detail on each chosen option.

It is intended that quantitative analysis will be conducted at a later stage of the Review. The options paper will provide more details on what quantitative analysis would be appropriate and indicative timing for when this analysis will be conducted.

Contents

1 Introduction

The COAG Energy Council has asked the Australian Energy Market Commission (AEMC or Commission) to report on a set of drivers that could impact on future transmission and generation investment.

The Commission concluded in the final stage 1 report that the Review should progress to stage 2. This approach paper is the first publication in stage 2, which:

- outlines the Commission's findings from stage 1
- outlines our proposed assessment methodology
- outlines issues and options under consideration
- outlines the proposed analysis to be undertaken in stage 2 and
- invite written submissions on the proposed approach.

This approach paper commences the start of stage 2 for the Review, as laid out in the terms of reference. In order to more accurately reflect the subject matter considered in this stage 2 of the Review the title has been changed from *Reporting on drivers of change that impact transmission frameworks* to *Coordination of generation and transmission investment*.

1.1 Terms of reference

The terms of reference for this reporting were received from the COAG Energy Council in February 2016.[1]

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 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

1 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

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, these are:

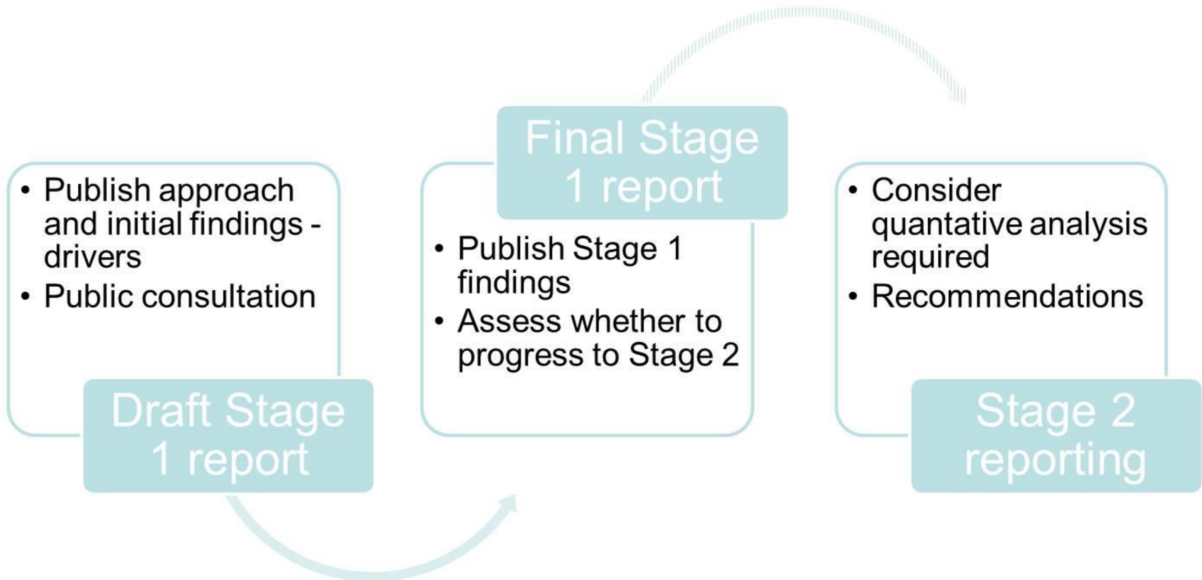
- government policies and international agreements
- technological developments
- the establishment and penetration of new business models
- the level of distributed generation
- the level of variance in forecasts
- national electricity market (NEM) rule and regulation changes.

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.[2]

1.2 Process for this Review

As outlined above the terms of reference require that a two-stage reporting regime be put in place. The structure for the 2017 Review is given in the following figure.

Figure 1.1 Structure of the 2017 Review



This final stage 1 report concluded that, based on the conditions identified in the terms of reference for this Review, as well as other developments in the energy market, the

2 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-impact-transmi/Final-Stage-1-report/AEMC-Documents/Final-Stage-1-report.aspx

reporting should progress to stage 2. The findings of stage 1, and the decision to progress to stage 2 are discussed in more detail in Chapter 2.

This publication is the first in stage 2 of this Review.

1.3 Purpose of this paper

This paper provides further detail on the issues that will be examined in more detail in the second stage of this Review. Specifically, it provides detail on the current arrangements for transmission and generation investment in the NEM and the potential issues associated with these arrangements. Potential options to address these issues are also identified.

This paper is designed to start the process for stage 2 and to define the issues that will be examined in more detail as the Review progresses. The paper aims to provide greater detail on the main issues that have been identified with respect to the coordination of transmission and generation investment and to provide an overview of some of the options to ameliorate these issues. The options identified in this paper are not an exhaustive list of potential changes that could be made to the regulatory framework and we welcome stakeholder feedback on the analysis and options presented in this approach paper.

1.4 Consultation process

This paper will be open for stakeholder consultation. The Commission invites comments from interested parties in response to this approach paper by **19 September 2017.** 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.

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". In particular, we welcome feedback on the various questions listed throughout this paper.

1.5 Next steps

Stakeholder submissions will inform the next stage of this Review. An options paper will be published in November 2017, which will narrow down the various options under consideration and provide more detail on each chosen option.

It is intended that quantitative analysis will be conducted later in this Review. The options paper will provide more details on what quantitative analysis would be appropriate and indicative timing for when this analysis will be conducted.

1.6 Structure of this paper

The rest of the paper is structured as follows:

- Chapter 2 summarises the finding from stage 1 of the Review
- Chapter 3 outlines the assessment framework to be used in stage 2

- Chapter 4 outlines the issues to be examined in more detail in stage 2 and the potential options to address these issues. The issues identified are:
  - transmission charging
  - transmission planning arrangements
  - access arrangements.

2 Findings from stage 1

Stage 1 of this Review analysed a number of drivers of transmission and generation investment. The analysis in stage 1 informed the decision to progress to the second stage. This chapter summarises the work conducted by the Commission in stage 1.

2.1 Overview of stage 1

The draft stage 1 report was published in April 2017 and presented the Commission's initial analysis on the drivers identified in the terms of reference. The draft stage 1 report was open to public consultation. This consultation period was an opportunity for stakeholders to provide comments and feedback to the Commission on the analysis presented in the draft stage 1 Report. Submissions were due on 16 May 2016 and five submissions were received.

This final stage 1 report was published on 18 July 2017 and presented the Commission's final analysis of the drivers of change in transmission and generation investment. Specifically, it provided a final analysis on developments in the drivers identified in the terms of reference over the past two years and identified expected future trends. The focus of the stage 1 analysis was on how any identified changes in the drivers of transmission and generation investment would impact on the level, location and technology of any new generation or transmission investment.

The terms of reference for this Review outlines the criteria that should be met for the Review to progress to the second stage. Specifically, the terms of reference states that:

> "At the first stage, analysis is undertaken on the set of drivers. This will 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, where this investment is uncertain in its technology and location.
>
> If there is, this is a trigger to move to the second stage of the process.[3]"

From this, the Commission considered three decision criteria, in particular whether:

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

This final stage 1 report concluded that, based on the conditions identified in the terms of reference for this Review as well as other developments in the energy market, the reporting should progress to stage 2.

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

2.2 Findings of stage 1

2.2.1 Changes to the drivers of transmission and generation investment

The analysis conducted by the Commission as part of stage 1 of this Review has concluded that the identified drivers of transmission and generation investment have changed considerably since July 2015.

Government policy and international agreements

Since July 2015, Australia has committed, under the Paris Agreement, to reduce carbon emissions by 26-28 per cent below 2005 levels by 2030. Despite the new emissions reduction target described above, the policy settings around emissions reduction have not changed since July 2015.

There has been recognition by a wide range of stakeholders that further action will be needed in order to reduce emissions from the electricity sector to meet Australia's agreed international commitments. Lack of sustainable policy in this area is creating uncertainty, which in turn is having a negative effect on investor confidence.

An important determinant of future generation technologies is emissions reduction policy. Therefore, until a stable emissions reduction policy is in place in the energy sector it is difficult to predict what the impact on generation, and in turn, transmission, investment will be.

Since the conclusion of stage 1 of this Review, the AEMC has been asked to develop design options for a Clean Energy Target by the governments of South Australia, Queensland, Victoria and the Australian Capital Territory, as recommended in the *Independent Review into the Future Security of the National Electricity Market*.[4] A final report on this advice is due in October 2017.

Technological developments

Since October 2015, there has been the retirement of two major coal-fired generators in the NEM, Northern power station in South Australia and Hazelwood power station in Victoria. AGL has also announced that Liddell power station will not operate post 2022. Given the age of the fleet of generation in the NEM, it is expected that retirements of thermal generation will continue.

At the same time as the retirement of thermal generation, there has been an increase in the penetration of renewable generation in the NEM. This has been supported by the incentives offered under the RET, in the form of an additional revenue stream of LGCs. The trend of renewable generation entering the NEM is expected to continue, especially given eligibility for the current RET scheme is due to end in 2020.[5]

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4 See: http://www.aemc.gov.au/News-Center/What-s-New/Announcements/Modelling-of-a-Clean-Energy-Target-mechanism

5 AEMO is currently tracking 19,102 MW of proposed new generation capacity. The technology mix of this new generation is 65 per cent wind, 25 per cent gas, 9 per cent solar and 1 per cent other generation.

As the most economic renewable generation technologies, wind and solar, are non-synchronous, system security considerations, such as system strength, may also determine future investment in generation and transmission.

Proliferation of new business models

New and innovative business models are entering the energy market, although at this stage many are at trial stage and their scale is small. The focus of these new business models has been, to date, on the consumer end of the market and maximising the benefits to consumers of one of the multiple value streams provided by distributed energy resources.

No clear "winner" has emerged at this time so the impact of innovative business models on transmission and generation investment is hard to gauge. In order to allow the continued development of new business models to provide a range of new energy service to consumers and networks, regulatory frameworks should remain flexible and retail market competition should be allowed to continue to evolve.

The level of distributed generation

The most significant distributed energy technology currently in the NEM is rooftop PV. From 2010 to March 2017, the installed capacity of small-scale PV systems has risen significantly, from around 100 MW to 4,600 MW. The trend in increased uptake of rooftop PV is expected to continue. The growth of rooftop PV is expected to come in the future from commercial and industrial sectors, rather than solely residential, which has been the main source of growth up to this point.

Given, high penetration rates of rooftop PV and its intermittent nature, it is expected that behind the meter battery storage will become more prevalent in the future. Battery storage would allow customers with rooftop PV to store the energy created in the middle of the day, when electricity demand is lower, and use this energy during peak times in the evening. By 2030 forecasts indicate that the number of storage systems in Australia will reach one million.[6]

The level of variance in forecasts

With increased penetration of distributed energy resources and improvements in energy efficiency, forecasting grid demand, and managing variances in supply may become more challenging. It is likely that given the nature of changes in the energy market that more granular and "bottom-up" data will be needed in order to accurately forecast future grid demand. The Commission understands that processes are underway to improve AEMO's forecasting methodologies.

NEM rule and regulation changes

Since 2015 there have been significant developments in the wholesale energy market, with outcomes now increasingly connected with environmental policy, the wholesale gas market and system security considerations.

6 Bloomberg New Energy Finance, Australia Behind-the-meter PV and storage forecast, 22 February 2017.

There are also a number of important reviews and rule changes that have recently concluded or are still under consideration by the Commission. These include the *System security frameworks* and the Reliability Panel's *Reliability standards and settings* reviews. In addition the AEMC is currently considering a number of rule changes including *Five minute settlement*, *Transmission connections and planning arrangements* and *Replacement expenditure planning arrangements*.[7]

In addition to the work of the Commission, other reviews of the energy sector are in process or have recently concluded. These include the *Independent review into the future security of the NEM* (the Finkel Panel Review) and the Department of Environment and Energy's 2017 *Review of Australia's climate change policies*.

Finally, since July 2015 there has been a trend toward government intervention in the energy market, with numerous projects announced. Government intervention may result in less coordination of generation and transmission investment than has previously occurred, which potentially increases risks for consumers.

2.2.2 Future outlook for transmission and generation investment

There were a number of offsetting factors that will impact on the need for transmission and generation investment identified in the stage 1 analysis.

Two factors were identified that may reduce the need for transmission and generation investment. First, the increased proliferation of distributed energy resources may reduce the need for large-scale grid-connected generation, but the impact of this is unlikely to be significant in the medium term. Second, the current uncertainty regarding emissions policy is having a negative impact on investor confidence and willingness to invest in new generation.

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 shape of the transmission network may need to change to deliver a reliable supply to consumers from the changing generation mix. This is because new renewable generation may wish to locate, and therefore connect to the transmission network, in areas that are far away from existing transmission infrastructure. Transmission investment may therefore be required, to the extent that it is needed to reliably supply consumers with electricity from these new generation sources. Two case studies, one from Western Victoria and one from Queensland were provided in the final stage 1 report to illustrate this issue.

The final stage 1 report found that, on balance the factors that will require further investment in transmission and generation are more significant. Therefore, there is likely to be a need for transmission and generation investment in the medium term.

7 See: www.aemc.gov.au

2.2.3 Location and technology of future investment

The final stage 1 report found that there are a number of factors that mean that the location and technology of future transmission and generation technology is uncertain.

Factors that will impact on the technology of future investment include:

- The observed trend of the exit of thermal generation and the entry of renewable generation is expected to continue.
- The future generation mix will depend on any future emissions reduction policies introduced in the generation sector.
- Technology costs are changing and new technologies, such as battery storage, will increasingly become economic in the future.
- The increased penetration of intermittent renewable generation may require new investment to maintain system security.

The location of future investment in transmission and generation is also uncertain. The following factors inform this finding:

- The changing generation mix has implications for the transmission network, as new renewable generation may locate in areas that are not well serviced by the current transmission infrastructure.
- Emissions reduction policy also has implications for the transmission framework if the policy is not geographically neutral.

3 Assessment framework

This chapter sets out the assessment framework for how the AEMC will conduct Stage 2 of this Review.

3.1 Requirements under the National Electricity Law

The overarching objective guiding the Commission's approach to this Review is the National Electricity Objective (NEO). The Commission's assessment of any related rule change requests must consider whether the proposed rules promote the NEO. The NEO is set out in section 7 of the National Electricity Law (NEL), which states:

> "the objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (A) price, quality, safety, reliability, and security of supply of electricity; and
>
> (B) the reliability, safety and security of the national electricity system"

3.2 Coordination of transmission and generation investment

In order to assess options that may improve the coordination of transmission and generation investment it is important to articulate what coordination means.

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. Transmission network service providers (TNSPs) need sufficient generation to reliably supply their customers and to meet their individual reliability standards.

Box 3.1 Access in the NEM

The NEM operates under what is called an open access regime. 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 networks undertake. These standards are set by state and territory governments. These standards generally ensure a level of redundancy on 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.

Load as a whole is therefore considered to receive some level of implied access 'right' or firm access to the network. Given this, consumers pay transmission use of system (TUOS) charges, either directly or indirectly via their retailers, in return for this access provided to them: the costs of the assets necessary to provide them with a reliable supply that comprise the shared transmission network together with operational expenses are recovered solely from load (i.e., customers).

When networks have reached their limit of how much energy it can transport, this ‘congestion’ can usually be relieved by augmenting the capacity of the network. Congestion occurs when the flow of electricity reaches the physical limit of the affecting part of the transmission network. Whenever a particular element on the network, for example a line or transformer, reaches its transfer limit and cannot carry any more electricity already, it is 'congested'. TNSPs are also permitted, but not obliged, to undertake capital expenditure to reduce congestion – within their own region, or between two regions – when any such options for augmentation passes a cost-benefit test, the regulatory investment test for transmission (RIT-T).

Generators have the right to negotiate a connection to the transmission network and pay a shallow connection charge relating to the cost of their immediate connection to the shared transmission network. But there is no firm access in that generators have no guarantee that they can export all of their output to the system. Therefore, generators do not pay any form of TUOS charge.

In the NEM, generators earn money by being dispatched. Generators do not have a firm inherent right to be dispatched,[8] nor do they have a right to be compensated when not dispatched.

Physical dispatch of electricity for generators is determined through AEMO's NEM dispatch engine (NEMDE) system, based on the dispatch offers of generators and the physical limits of the transmission system. In other words, if the network is congested, generators face a risk of not being dispatched - being constrained-off the system - or, in some cases, being constrained on. NEMDE also determines the physical dispatch of load.

The focus of transmission businesses, and so their investment and operation decisions, is to deliver a reliable supply to consumers and to make offers to connect generators and load to their network. The development of transmission infrastructure to enable the export from generators will only occur to the extent that is necessary to ensure consumers receive a reliable supply of electricity.

For TNSPs, the cost of the transmission system includes building the required infrastructure to reliably supply their customers. This includes augmenting the network to meet increasing demand, replacing existing assets when they reach the end of their life and maintaining the network as required.

Included in the total cost of the transmission network to consumers is the cost of congestion (see Box 3.1 for a description of congestion). There is a trade-off between the cost of augmenting the network to alleviate a constraint and the benefit that accrues to generators and consumers as a result of this investment. The benefit of alleviating a network constraint can be thought of as the difference in generation costs that could be achieved when easing constraints allows more or cheaper sources of energy to deliver supply. An efficient level of congestion occurs when the cost of undertaking any more investment would be greater than the benefit provided, in terms of reducing the productive cost of reliably servicing demand.

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

The objective for TNSPs is to meet the demands of their customers by the least-cost combination of transmission and generation, so consumers do not pay more than they need to. In order to achieve this TNSPs conduct planning[9] to determine network replacement and augmentation investment decisions. TNSPs are also subject to incentive regulation and must follow a regulatory process to determine significant investment decisions. These planning and investment processes determine the location and capacity of the network.

For generators, the decision of when and where to locate is driven by a number of factors. These include information and price signals from the wholesale and contract markets, as well as information from TNSPs. These factors provide financial incentives to make efficient decisions by trading off the potential costs of transmission network congestion they may face with other relevant factors, such as proximity to fuel source or renewable energy resources.

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. Generation 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 meet TNSPs' statutory and regulatory obligations to reliably supply consumers, at least cost.

These differences have the potential to result in a development path that does not minimise the total system costs to 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 they impose on the transmission network
- investment decisions by each generator and TNSP incorporating this information and being 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 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

9 Transmission planning is discussed in more detail in Chapter 4.

- 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 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 innovative, 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.

3.3 Assessment criteria

In order to articulate how the Commission will consider balancing the criteria outlined above, the Commission has set out a number of principles to guide the development of options, and assessment of these options, with the focus on improving the coordination of generation and transmission investment. These principles are:

- **Efficient investment in transmission and generation investment:** TNPSs should be able to trade-off the cost of augmenting the network with the costs of managing congestion, noting that building out all constraints is unlikely to be efficient (i.e. the optimal level of congestion is not zero). Similarly, generators should have incentives to invest in new plant where and when it is efficient to do so. Information and price signals should provide financial incentives for generators and load to make efficient location decisions by trading off the costs they impose on the shared transmission network with other relevant decision factors such as proximity to fuel source. However, there are costs associated with the provision of transmission and generation investment, which should be assessed against the value to consumers.
- **Efficient operation of the network and market dispatch**: TNSPs should face incentives to operate the network to provide an efficient level of capacity, maximising availability when the value of network capacity is at its highest (such times may occur when congestion occurs). Efficient operation decisions occur when parties have clear responsibility and accountability for operation. Similarly, generators should have incentives to offer their energy into the wholesale market at an efficient price, resulting in wholesale market outcomes being explained in terms of the underlying supply and demand conditions.
- **Appropriate allocation of risks to parties best placed to bear them:** Regulatory and market arrangements should be designed to explicitly take into consideration the trade-off between the risks and costs of providing a reliable supply of electricity. Risk allocation and the accountability for investment and operational decisions should rest with those parties best placed to manage them. Under a centralised planning arrangement, risks are more likely to be borne by consumers.

Solutions that are better able to allocate risks to market participants such as commercial businesses, who are better able to manage them are preferred, where practicable.

- **Maintaining a secure and reliable power system:** Regulatory and market design arrangements must take into account the need to support the safe, secure and reliable supply of electricity to consumers. Such outcomes are particularly important in the context of transmission and generation since the consequences potentially have greater effect. Regulation may be required to safeguard these outcomes.
- **Transparency through the provision of timely and accurate information:** Market and regulatory arrangements should promote transparency as well as being predictable, so that market participants are informed about aspects that affect reliability, and so can make efficient investment and operational decisions. Simple frameworks tend to result in more predictable outcomes and are lower cost to implement, administer and participate in.

More fundamental changes to the existing NEM would clearly come with significant costs. These costs would include requirements for changed and additional systems, and the introduction of complex methodologies. Such costs will also be considered by the Commission through this Review.

The Commission welcomes stakeholder feedback on these principles.

3.4 Assessment approach

The Commission intends to adopt the following approach to progressing Stage 2 of this Review.

1. **Define the issues**

   The first step in our assessment framework is to understand the drivers of change that are impacting transmission and generation investment. Our analysis on this was completed in Stage 1, and is summarised in chapters 2 and 4 of this report. The Commission welcomes comments from stakeholders on the issues that have been identified with respect to the coordination of transmission and generation investment.

2. **Determine the options available**

   The Commission's Review will consider possible changes to the existing market and regulatory arrangements for generation and transmission investment that may address the drivers of change identified above. The Commission's preliminary views on the options are discussed in chapter 4.

3. **Assess the range of options against the NEO and guiding principles**

   Any recommendations for potential changes to market and regulatory frameworks developed by the Commission will need to result in net benefits to the market and promote the long-term interests of consumers, consistent with the

NEO. The Commission's assessment of the options, and the development of recommendations in this Review will also be guided by the framework principles set out above.

An options paper will be published in October 2017, which will narrow down the options under consideration and provide more detail on each chosen option. The options paper will also provide more details on what quantitative analysis would be appropriate to evaluate them and indicative timing for when this analysis will be conducted.

4 Issues under consideration

Based on the Commission's analysis of the drivers of change in Stage 1 of this Review, the Commission considers that there are three issues that should be considered through this Review, in light of the drivers of change affecting the coordination of generation and transmission investment, specifically:

- transmission charging arrangements
- transmission planning arrangements
- access arrangements in the NEM

These are discussed in turn below.

4.1 Transmission charging arrangements

Transmission charging arrangements determines *who* pays for the services provided by the transmission network, and *how* the costs of the transmission network are recovered.

4.1.1 Current arrangements

Box 4.1 Current transmission charging arrangements in the NEM

Who pays for the transmission network?

The focus of TNSPs, including their operation and investment decisions, is to deliver a reliable supply of electricity to consumers, as well as to make offers to connect to generators and loads that wish to connect to the network. Because there is an obligation on TNSPs to reliably supply their customers, it is customers who fund investments in the transmission network that enable export of energy from generators, and relieve congestion where necessary. The costs of the service (i.e. transmission use of system (TUOS) charges) associated with providing this reliable supply is therefore recovered solely from load (i.e. customers, either directly or indirectly through their retailer).

Generators have the right to negotiate a connection to the transmission network and in doing so pay a shallow connection charge relating to the cost of their immediate connection to the shared transmission network. But, because the development of transmission infrastructure to enable the export of energy from generators only occurs to the extent that it is necessary to make sure reliability of electricity supply to consumers, generators do not pay any form of TUOS charge.

How are the costs calculated?

TNSPs are subject to economic regulatory oversight by the AER in relation to their augmentation, replacement, operating and maintenance costs for the provision of prescribed services. TNSPs must apply to the AER, for the AER to assess its revenue requirements. The AER sets a maximum allowed revenue that a network can recover from consumers during a regulatory period. The TNSP's maximum allowed revenue is recovered through TUOS charges to consumers.

Under Chapter 6A of the NER there are a set of pricing provisions, which set out how TUOS charges are to be recovered. These are based on a set of pricing principles and require TNSPs to develop separate prices for each category of prescribed transmission service.[10]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 are 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 (CRNP)), or based on a reasonable estimate of future network utilisation and the likely need for future transmission investment (modified CRNP), which has the objective of providing more efficient locational signals.[11]

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 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.

4.1.2 Issues with current arrangements

The Pricing Principles for prescribed transmission services in Chapter 6A of the Rules require that the costs of the shared transmission network are to be recovered solely from load. As generators charges relate only to the cost of their immediate connection to the shared transmission network, the charging regime for generation can be characterised as a 'shallow' connection charging approach.

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. Generators do not currently receive any guaranteed service or firm access from the transmission network, and so do not pay transmission charges.

However, the consequences of this is that generators, unlike large customers, do not see any signal of the costs they impose on the shared network through their locational decisions. While this may have not been significant in the past, since the current transmission system is built around existing generation located near to fuel resources such as mines or gas pipelines, this may not continue in the future. The increasing penetration of renewable resources, typically locating at the outer edges of the grid, will potentially lead to increased costs of transmission in order to provide a reliable supply of energy to consumers. Therefore, the absence of a price signal to generators of the

10 Clause 3.6.5(a)(5) of the Rules provides for jurisdictions to establish inter-regional charges through inter-governmental agreement. However, in practice, inter-regional transmission service payments have been negotiated only between South Australia and Victoria.

11 NER clause 6A.23.3(d)(1)-(2).

impact of their locational decisions on transmission network costs could result in inefficient overall locational decisions that increase costs for consumers.

One clear example of this is in Western Victoria, where the announcement of the Victorian Renewable Energy Target has resulted in AEMO receiving new connection applications for over 5,000MW of capacity in Western Victoria, with 80 per cent of these applications seeking to connect to the 66 kV and 200 KV network, given the favourable location of this part of the network for wind farms.

AEMO is currently undertaking a RIT-T to assess the technical and economic viability of increasing transmission network capability in Western Victoria. For an option (e.g. augmentation of the network) to pass the RIT-T it will have to be demonstrated that it will create a net benefit for consumers. Preliminary studies show that the cost of removing all constraints in the network would cost in excess of $500 million, which is likely to be uneconomic. Therefore, AEMO's preliminary conclusion is that it may be more efficient to build new transmission lines closer to Moorabool, where constraints are more severe and line lengths are short.[12] Regardless, whatever transmission augmentation occurs, this will be fully funded by consumers, where it may have been more appropriate for the generators choosing to locate out in Western Victoria to face some of these costs.

In addition, this disconnect between load customers paying TUOS charges, and generators not paying TUOS charges 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 weird incentives for proponents of large scale batteries. AEMO recently released its guidance on *Interim arrangements for utility scale battery technology.* Consistent with the Commission's view, as expressed in the *Integration of storage report,* 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.[13]

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/DNSP consistent with principles set out in the NER, since each NSP determines 'use of system' charges according to its own pricing methodology. AEMO and the AEMC are currently working together in order to consider whether future changes to these arrangements in relation to batteries are needed. The Commission will consider this issue as part of this Review.

12 See: AEMO, Victorian Annual Planning Report 2017, p. 36; AEMO, Western Victoria Renewable Integration, Project Specification Consultation Report, April 2017, p. 36. For further discussion see the final report for Stage 1 of this reporting.

13 See: http://aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/New-Participants/Interim-arrangements-for-utility-scale-battery-technology.pdf

It is also worth mentioning that market network service providers (MNSPs) do not currently pay TUOS charges. Depending upon the conclusions relating to whether large scale batteries or not, this could also require some consideration.

Question 1 Transmission charging arrangements - issues

(a) Do you agree with the issues identified with respect to transmission charging, and how this impacts on the coordination of transmission and generation investment?

(b) Are there any other issues that should be examined as part of this Review?

4.1.3 Options for consideration

As noted above, the issues associated with transmission charging are intrinsically tied up with access and planning arrangements, and so these matters will be considered holistically by the Commission. Some options that could be considered in relation to transmission charging arrangements, specifically are:

- requiring generators to pay (at least some form of) TUOS charge - obviously what generators pay is related to the service that they receive and so what access arrangements there are
- in the absence of requiring generators to pay TUOS charges, consideration of whether a separate registration category for storage (either batteries or pumped storage) could be more appropriate, which would allow for specific consideration of TUOS arrangements for these participants
- requiring large scale batteries to be registered as both generators, and market customers, but be treated as generators for the purpose of TUOS services with all generators becoming liable for TUOS charges when they are net importers from the network.

Question 2 Transmission charging arrangements - options

(a) Are any of the above options worth of further consideration, or no further consideration? Why? Why not?

(b) Are there any additional options that should be considered through this Review?

4.2 Transmission planning arrangements

4.2.1 Current arrangements

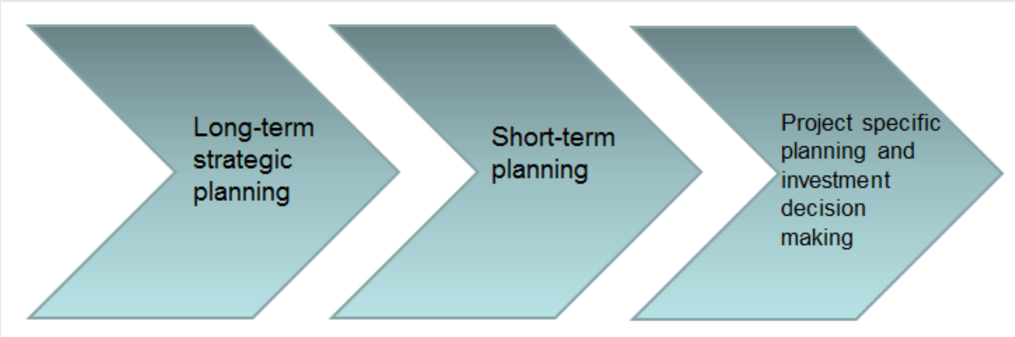
The current transmission planning and investment decision frameworks are described in the box below.

Box 4.2 Current planning arrangements in the NEM

Planning concerns the investment needs of the transmission network in general terms, rather than specific investment decisions. However, specific investment decisions by networks will be made as a result of planning.

Transmission network 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 needs to reliably supply consumers. Short-term planning has a focus on the near term and specific investment needs. Project specific planning relates to a particular investment need and culminates in an investment decision.

Figure 4.1 Planning horizons



As there are numerous planning horizons, each with a different focus, there are a number of outputs produced as part of the transmission network planning process. Responsibility for different elements of the planning process rests with different parties, depending on the form of planning undertaken. Planning also takes place at a national and jurisdictional level with this determining which body undertakes the planning work.

AEMO, as national transmission planner (NTP) and jurisdictional planning bodies therefore share responsibility for transmission network planning. Jurisdictional planning bodies are, in most cases, the local TNSP except in Victoria (see table below). AEMO is the jurisdictional planning body in Victoria as part of its Declared Network Functions under the National Electricity Law.

Table 4.1 Jurisdictional planning bodies in the NEM

Jurisdiction	Jurisdictional planning body
Queensland	Powerlink
New South Wales (and Australian Capital Territory)	TransGrid
Victoria	AEMO
South Australia	ElectraNet
Tasmania	TasNetworks

AEMO is the NTP and conducts long-term strategic planning across the NEM. This planning process results in the publication of the National Transmission Network Development Plan (NTNDP), which provides a holistic, independent and strategic 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.

AEMO is required to consult with stakeholders in advance of the publication of the NTNDP. Therefore, jurisdictional planning bodies do have a role in the preparation of the NTNDP as part of this wider consultation; however, there is nothing in the Rules to require TNSP involvement.

Short-term planning is undertaken by the jurisdictional planning bodies. 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 an annual planning report, which must (amongst other things) set out what the TNSP is doing to meet its reliability standards.

TNSPs also undertake project specific planning through a cost-benefit test, which 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 investment options[14] (that exceed $6 million) 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 option which maximises net economic benefits and, where applicable, meets the relevant reliability standards. If a proposed investment passes the criteria governing the RIT-T, the TNSP may proceed with the investment, and this will be funded by market customers through transmission use of system (TUOS) charges.

The primary purpose of the current framework of annual planning reports and RIT-Ts is to support the planning of, and decisions on investment in, a network by:

- creating incentives for, and a framework within which, TNSPs can consider potential non-network solutions to network constraints or limitations
- establishing clearly defined planning and decision making processes to assist TNSPs in identifying the solutions to network problems in a timely manner
- providing transparency on network planning activities to enable stakeholder engagement with those activities in order to support the efficient investment in the network.

14 The AEMC have, in the *Replacement expenditure planning arrangements* rule change made a rule that will require that a RIT-T for replacement expenditure from 18 September 2017. Projects that are replacement projects and have reached a "committed" stage before 30 January 2018 will not be subject to the RIT-T requirement. For more information see: http://www.aemc.gov.au/Rule-Changes/Replacement-Expenditure-Planning-Arrangements

TNSPs are responsible for making investment decisions, in accordance with their planning activities set out above. TNSPs must make investments in order to meet the jurisdictional reliability standard. TNSPs are also permitted, but not obliged, to undertake capital expenditure to reduce congestion - within their own region or between two regions - when this passes the RIT-T. Any investments are funded from revenue received from consumers.

The planning and investment framework supports the incentive-based economic regulatory framework. TNSPs are also subject to economic regulatory oversight by the AER in relation to their augmentation, replacement, operating and maintenance costs for the provision of prescribed transmission services. TNSPs proposed revenue requirements are subject to assessment by the AER..

4.2.2 Issues with current arrangements

A key part of coordinating transmission and generation investment is having sufficient information flows between the two sectors and so efficient investment decisions being made by both sectors. Drawing on the discussion above, if generators were faced with a price signal about where to locate, this would drive more efficient locational decisions by generators and so more efficient transmission planning by the TNSP since it would be able to factor in these generator decisions into its planning process. At the moment, TNSPs use the RIT-T process to consult and test assumptions with generators, as well as information gained through connection applicants, as inputs into planning their network.

Historically, the consequences of whether or not transmission and generation investment was co-ordinated were less material. Significant investment in generation and transmission occurred prior to the introduction of the NEM, with transmission planning driven by governments or government utilities making investment decisions with respect to both transmission and generation. For the few decades or so of the NEM, generation location decisions were relatively easy to predict and to be factored into RIT-Ts. However, more recently, there are greater changes in the potential pattern of generation in the NEM, which is making it harder for a TNSP to settle on assumptions that underpin a robust RIT-T assessment. The increased potential for the TNSP to invest in a transmission path that does not enable the least-cost combination of generation and transmission could result in inefficiencies both within and between regions.

One way to address this would be to have a more direct price signal for generators about where to locate, such as those discussed above, which would provide generators with better signals about where to locate. This price signal would presumably be based on plans undertaken by the TNSP, and so would result in better coordination.

In the absence of such a price signal, it may be worthwhile considering whether the current arrangements encourage sufficient information flows. Broadly, the Commission considers that the current planning frameworks are fit for purpose in this regard. In particular, the Commission's recent final determination on the *Replacement expenditure rule change request,* will facilitate increased information flows in relation to replacement expenditure.

Coordinating generation and transmission investment through planning, as noted above, could be improved. However, such issues are likely to be exacerbated in the situation of multiple generators. This issue was discussed in detail in the *Independent review into the future security of the National Electricity Market,* which noted that:[15]

> "In the event that a resource that is remote from the existing network is of sufficient quality that a generator is prepared to pay the cost of connection, they have an incentive to build the minimum capacity necessary to support their needs. That is, generators are unlikely to pay for the construction of a transmission line that is of sufficient scale to enable other generators to connect in the same area. If other generators subsequently move into the same area, there is a risk that the network would become congested and would need to be upgraded or duplicated. This would come at a significantly higher cost than if the network had been built to an appropriate scale in the first place.
>
> [...]
>
> The Panel considers that there may be a future role for governments in facilitating considered and targeted investments in network infrastructure to enable the efficient development of renewable energy resources. This would be necessary if it becomes clear that it is not possible to resolve the coordination problem between generators and TNSPs under the current regulatory framework. It would likely require governments to make decisions on particular transmission investments.
>
> [...]
>
> The AEMC should develop a rigorous framework to enable the evaluation of these projects, including guidance for governments regarding the circumstances that would warrant government intervention to facilitate specific transmission investments. This should minimise the risk of consumers bearing the cost of unnecessary transmission infrastructure."

Some TNSPs and DNSPs have started considering 'renewable energy hubs': most notably, TransGrid who received funding from ARENA to investigate feasibility of such hubs[16]; and Powerlink and the Queensland Government's consideration of 'Renewable Energy Zones' through the Economic Development Queensland and Powering North Queensland Plans.[17] The Commission will consider the above framework, what it might look like and other associated issues through this Review.

Question 3 Transmission planning arrangement

(a) Do you agree with the issues identified with respect to transmission planning, and how this impacts on the coordination of transmission and

15 Finkel Panel, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future,* June 2017, p.p. 125-129.

16 See: https://arena.gov.au/assets/2017/05/Renewable-Hub_Knowledge-Report_Final-1.pdf

17 Powerlink, *Transmission Annual Planning Report,* June 2017, pp. 140-142.

generation investment?

(b) Are there any other issues that should be examined as part of this Review?

4.2.3 Options for consideration

As noted above, the issues with transmission planning are intrinsically tied up with access and charging arrangements, and so these matters will be considered holistically by the Commission. Some options that could be considered in relation to transmission charging arrangements, specifically are:

- implement some type of price signal for generators, the reaction of generators to this price signal would then drive planning decisions for TNSPs
- develop a mechanism where generators could group together to jointly fund slightly larger connection assets, resulting in lower overall costs to the network, and better utilisation of assets, reducing costs to connect applicants and so consumers (although, obviously, this would have to be done in a way that did not increase costs or risks to consumers)[18]
- implement Competitive Renewable Energy Zones, similar to those that have been introduced in Texas.[19] Here, the Public Utility Commission of Texas (PUCT) identified areas with potential wind capacity. It then facilitated a competitive process where parties could nominate zones, and propose transmission solutions. The outcome resulted in the transmission infrastructure being built in these areas, which subsequently attracted new wind farms to these locations: a "build it and they will come" approach.[20]

Question 4 Transmission planning arrangements - options

(a) Are any of the above options worth of further consideration, or no further consideration? Why? Why not?

(b) Are there any additional options that should be considered through this Review?

4.3 Access arrangements in the NEM

4.3.1 Current arrangements

The current arrangements for access in the NEM are described in the box below.

18 Under clause 5.19 of the NER it is possible to build Scale Efficient Network Extensions, however feedback from stakeholders indicates that the process for such investments has many practical difficulties and could be improved. The Commission will consider any such feedback on this through this Review.

19 The appropriateness of any scheme introduced in other markets would have to be considered in the context of the market design and conditions in Australia.

20 For more information see: Public Utility Commission of Texas, *Scope of Competition in Electric Markets in Texas*, Report to the 81st Texas Legislature, January 2009, pp23-26. Available at: https://www.puc.texas.gov/industry/electric/reports/scope/2009/2009scope_elec.pdf

Box 4.3 Current access arrangements in the NEM

The NEM operates under what is called an open access regime.

The focus of transmission businesses, including their operation and investment decisions, is to deliver a reliable supply to consumers and to make offers to connect to generators and loads that wish to connect to their network.

The development of transmission infrastructure to enable the export of energy from generators will only occur to the extent that is necessary to ensure consumers receive a reliable supply of electricity.

Under this open access regime, a generator has a right to connect to the transmission network but there is no guarantee they will be able to sell their output.[21] A generator's right to use the transmission network, and so earn revenue, is based solely on whether or not it is dispatched by AEMO in the wholesale market. Dispatch of electricity is determined by dispatch offers of generators and the level of network congestion.

Therefore, because there is an obligation on transmission businesses to reliably supply their customers, it is customers who fund investments in the transmission network that enable export of energy from generators, and relieve congestion where necessary. The costs of the assets necessary to provide a reliable supply are recovered solely from load (that is, customers).[22]

As generators have no access right to the transmission network, that is, there is no guarantee they will be able to sell their output, they only pay charges relating to the cost of their immediate connection to the shared transmission network, the charging regime for generation can be characterised as a "shallow" connection charging approach.

4.3.2 Issues with the current arrangements

Under an open access arrangement generators have limited ability to manage their exposure to dispatch uncertainty or volume risk. Generators could be constrained off at any time.[23] While generators seek to forecast network conditions, and behaviour of other generators, in order to manage these risks, it is likely becoming harder to predict dispatch outcomes due to the increasing amount of intermittent generation into the NEM, adding another factor (weather) that needs to be considered in any analysis.

Over the past few years, congestion in the NEM has reduced, and generators do not seem to have been as concerned about such risks. Dispatch uncertainty may have been tempered due to a number of retirements throughout the transmission network,

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

22 Generators pay for connection assets which are part of the shared transmission network. Consumers only pay for what is needed for a reliable supply of electricity.

23 Generators may choose to fund augmentations to the shared transmission network in order to reduce congestion and the risk of constraints. However, generators receive no exclusive 'right' to the use of such augmentations, and the benefits of the reinforcement may accrue to other generators.

creating spare capacity. However, issues associated with this will likely increase as more renewable generators continue to seek to connect, at the edges of the grid where the network is weaker and less developed, creating congestion or other security concerns such as system strength. For example, Queensland has nearly 2,500 MW of proposed renewable energy projects in the north of the state. If all of these are built, significant congestion will be faced by these generators, unless the network is augmented in order to reliably supply consumers.

A lack of certainty for generators over dispatch outcomes can impact financial markets, in that it may limit whether generators can continue to meet their contractual obligations. As a result, generators may reduce the volume of contracts offered, reducing liquidity in the contract market, or factor in a risk premium, resulting in higher contract prices. This, in turn, could be reflected in higher prices to consumers.

Question 5 Transmission access arrangements

(a) Do you agree with the issues identified with respect to transmission access arrangements, and how this impacts on the coordination of transmission and generation investment?

(b) Are there any other issues that should be examined as part of this Review?

4.3.3 Options for consideration

As noted above, the issues planning with access arrangements are intrinsically tied up with transmission planning and charging arrangements, and so these matters will be considered holistically by the Commission. Some options that could be considered in relation to access arrangements, specifically are:

- building out all congestion (which occurs in Western Australia), which is obviously inefficient since the cost of this, would exceed the value placed on it by consumers
- the status quo of open access
- implementing a transmission reliability standard for generators (i.e. one standard that would be the same for all generators), which the TNSP would be required to meet, and would provide generators with increased certainty about the level of dispatch
- an optional firm access type model, or a simplified version thereof, which gives generators the option of obtaining firm financial access rights for any quantity of their capacity, with this driving planning decisions by the TNSP
- locational marginal pricing, combined with financial transmission rights: generators would be settled at their locational marginal price, but would have the ability to obtain fully firm financial transmission rights in order to manage the price risk that they would then face.

Question 6	Transmission access arrangements - options
(a)	**Are any of the above options worth of further consideration, or no further consideration? Why? Why not?**
(b)	**Are there any additional options that should be considered through this Review?**

4.4 Conclusion and next steps

The above sections provide an overview of the issues associated with transmission charging, planning and access arrangements. It also provides a summary of some of the options that the Commission considers could be considered through this project.

Stakeholder feedback is welcomed on the questions discussed above. The feedback will be incorporated into the Commission's development of an options paper for this Review, which will be published in November 2017. The options paper will provide further analysis on the issues set out above, narrow down the options under consideration and provide more detail on each chosen option.

It is also intended that quantitative analysis will be conducted at a later stage of the Review. The options paper will provide more details on what quantitative analysis would be appropriate and indicative timing for when this analysis will be conducted.