REVIEW

Australian Energy Market Commission

DRAFT STAGE 1 REPORT

Reporting on drivers of change that impact transmission frameworks

11 April 2017

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Stage 1 Report

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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 Commission has been requested by the COAG Energy Council to report, on a biennial basis, on a set of drivers that could impact on future transmission and generation investment. The process for the reporting regime was laid out in a terms of reference received by the Commission in February 2016.

The reporting regime is a two stage process. The first stage outlines the drivers of transmission and generation investment specified in the terms of reference and provides the Commission's analysis of these drivers. If it is deemed necessary the reporting will progress to a second stage, where an assessment of whether implementing a model that would introduce more commercial drivers of transmission and generation development would meet the National Electricity Objective will be made.

This report is the first of two publications in stage 1 of the reporting. It presents the Commission's draft analysis on the drivers of transmission and generation investment. There appears to be a large degree of uncertainty regarding future patterns and drivers of generation and transmission investment.

The uncertainty surrounding future government environmental policies means that it is difficult to predict the technology of new generation investment and therefore the future generation mix. This, in turn, leads to uncertainty regarding future transmission investment, as the technology of generation can have an impact on its location and therefore on the potential future needs of the transmission network.

Technological developments also create uncertainty for future generation and transmission investment. The current pace of technological change implies that the generation mix in Australia will change over the coming years, with the exit of emissions-intensive thermal generation and the entry of lower-emissions gas and renewable generation. Further, with a reduction in the cost of new technologies, there has been a trend toward increased penetration of distributed energy resources. With this increased uptake of distributed energy, there is potential for new business models to provide value to energy consumers. The effect of these developments on electricity demand, and therefore on generation and transmission investment, are difficult to assess at this stage.

There are many other developments currently impacting on the energy market at this time. Developments in the wholesale markets; including spot markets, contract markets and interconnector flows; have changed in the past two years, as a result of a number of changes to market conditions. Numerous rule changes and reviews are currently being undertaken by the Commission and other parties. Governments have announced interventions into the energy market. These are all likely to influence the coordination of transmission and generation investment.

The Commission is conscious that, in light of the changes on foot and processes in train and policy uncertainty, a pragmatic approach to evaluating the need for further reform in the market is needed.

This paper is subject to public consultation and we welcome stakeholder feedback on the analysis presented and on additional areas of focus. Stakeholder feedback will be an important input into the final stage 1 report, which will be published later this year.

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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.

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).

This 2017 review is the first time this reporting regime is to be undertaken by the AEMC.

The reporting regime, 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 are outlined below:

- 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 introduce more commercial drivers into transmission and generation development would meet the National Electricity Objective (NEO).

The drivers that the reporting is to consider in terms of influencing the amount of transmission and generation investment, as well as its location and technology, 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;

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-reference.aspx

- the level of variance in forecasts; and
- national electricity market (NEM) rule and regulation changes.

All of the above drivers will be examined by the Commission as part of this review.

1.2 Statement of approach

In July 2016 the Commission published a statement of approach on reporting on drivers of change that impact on transmission frameworks.[2]

The statement of approach was published in response to the terms of reference and provides further detail on the Commission's proposed methodology and approach to consultation that we will adopt in conducting this biennial reporting on an ongoing basis.

In particular, the statement of approach provides background to the request for advice from the COAG Energy Council and detail on how the Commission proposes to approach each stage of the two-stage reporting regime. The statement of approach should be read as background to this report.

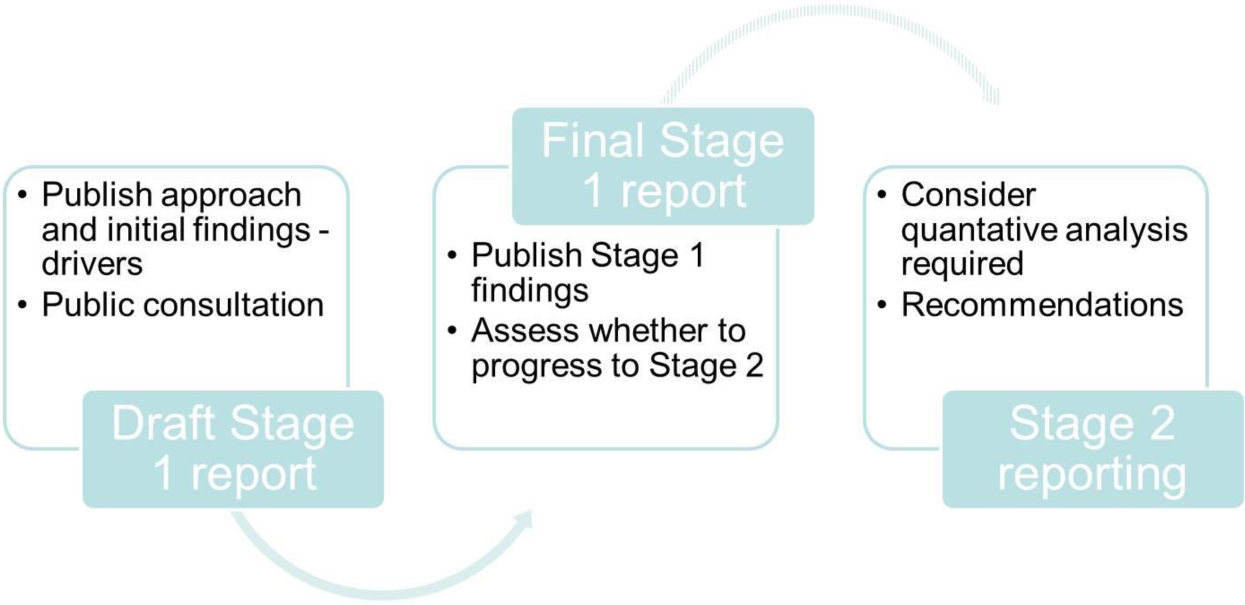
1.3 The 2017 Review process

As outlined above the terms of reference require that a two-stage reporting regime be put in place.

This report is the first of two reports that will make up stage 1 of the 2017 review process. The structure for the 2017 review is given in the figure below.

2 The statement of approach is available on the AEMC website at http://www.aemc.gov.au/getattachment/4c3b2239-9f6d-44d3-afe5-b4dd3cbbd685/Statement-of-Approach.aspx

Figure 1.1 Structure of the 2017 Review



This interim stage 1 report presents the Commission's initial analysis on the drivers identified in the terms of reference. This can be considered the 'draft report' referred to in the statement of approach. This report will be subject to public consultation and is therefore an opportunity for stakeholders to provide comments and feedback to the Commission on our analysis. Stakeholder submissions will be a key input into the final stage 1 report. The Commission is also interested in hearing suggestions from stakeholders on additional areas of focus that could be included in the final stage 1 report.

The final stage 1 report will comprise the Commission's final analysis of the drivers of change in transmission and generation investment. Specifically, it will report on developments in these drivers over the past two years and identify expected future trends. The focus of the analysis will be 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.

A decision on whether stage 2 reporting is required will be made in the final stage 1 report.

1.4 Strategic Priorities

The Commission will also be conducting a review of its energy sector strategic priorities this year, as requested by the COAG Energy Council. An approach paper on the scope of the work and the advice that will be developed has been published by the Commission.[3]

3 The approach paper is available on the AEMC website.

The subject matter of this review is also relevant to the strategic priorities process, which will provide strategic advice on the wholesale energy sector to inform the COAG Energy Council's own priority setting.

Stakeholders are welcome to, through the consultation process for this review, provide comments and feedback that they think is relevant for the Strategic Priorities work. The Commission recognises that market participants are involved in many public consultation processes and so welcome any opportunities to reduce the burden on participants.

It is also possible that any further stakeholder engagement undertaken for this Review, for example public forums, workshops or meetings, may also be used as an input into the Strategic Priorities work.

1.5 Consultation

The Commission invites written submissions on this report by **16 May 2017**. The Commission also welcomes one-on-one meetings with interested stakeholders. Please contact Therese Grace on (02) 8296 7842 if you would like to arrange a meeting.

In particular, the Commission would welcome feedback on the below three questions. As noted above, the focus at this stage of the reporting is on the analysis of the drivers identified in the terms of reference.

Question 1	**Do you agree with the Commission's analysis of the drivers of change in transmission and generation investment?**

Question 2	**How do these drivers impact on transmission and/or generation investment?**

Question 3	**Are there any additional areas that should be considered in this Review?**

1.6 Structure of this report

The rest of the report is structured as follows:

- Chapter 2 outlines the assessment framework to be used in this Review.
- Chapter 3 describes the background to the drivers of change that impact transmission and generation investment in general terms.
- Chapters 4 - 6 examine specific drivers in more detail, these are:

- government policies, regulations and international agreements;
- technological developments and new business models; and
- other trends in the energy market that impact on transmission and generation investment respectively.

- Appendix A provides information on the number of regulatory investment tests for transmission that have been undertaken in the NEM.

2 Assessment framework

This chapter sets out the assessment framework for how the AEMC will conduct the 2017 review, building on the approach that was set out in the statement of approach for this reporting.

2.1 Requirements under the National Electricity Law

The NEO provides overall direction for this reporting. The NEO is set out under section 7 of the National Electricity Law (NEL), and states that:

> "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."

2.2 Approach to stage 1 analysis

The drivers for change identified in the terms of reference form the basis for what will be assessed in this reporting. These are listed in chapter 1, and discussed in more detail in the following chapters.

It is important to note that in undertaking stage 1 of the 2017 review, we will provide a *qualitative* assessment of the magnitude of the change in drivers since July 2015 and therefore whether there are grounds for undertaking the stage two analysis involving a more comprehensive (including quantitative) assessment of the drivers.

The qualitative analysis will seek to determine whether there may be a substantial change in the set of drivers to suggest that there may be indicators of an environment of major investment, where this investment is uncertain in its location and type.

In order to assess the magnitude of the change in a particular driver, we will undertake the following approach:[4]

- the historic status of the drivers-for-change at the time of the last review (this will become the base case); and
- the current status of the drivers-for-change and possible future status over the next five to ten years (this will become the counterfactual against which we will assess the justification for proceeding to a stage 2 review process).[5]

These two steps are discussed further below.

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4 This is consistent with the statement of approach for this reporting.

5 As noted in the statement of approach any change to the current framework will require a lead time for implementation and as such, assessment should consider how conditions may change over the next five to ten years.

2.2.1 Establishing the base case

In establishing the base-case we first set out what we consider the market conditions were for each driver in the relevant comparison period, that is, July 2015. These conditions are documented in each of the following chapters, for each of the respective drivers.

2.2.2 Establishing the counterfactual

In establishing the counterfactual we:

- set out what the current market conditions are for each driver. Assessment of the current market conditions are based on, amongst other things, the legislation and regulations existing at the current time, that is, when we are undertaking the stage 1 work; and
- given the lead time for any changes, we also assess how these conditions might change in the future (over the subsequent 5-10 years), based on a literature review of relevant, publicly available, reports on these matters.

Energy market arrangements need to be flexible and resilient enough to respond to change. Energy policy and the associated regulatory framework must be able to adapt to these changes to allow a dynamic market response. In undertaking this review, we will therefore consider market participants' views and work on these matters, and consideration of different scenarios. Submissions will be an important input in this regard.

2.3 Out of scope

In stage 1 of this review, we are solely focussing on the drivers and whether they have changed in a substantial manner. We will not be considering what changes to the transmission frameworks, if any, would be considered if the drivers were found to have changed materially. That would be considered in stage 2, if the Commission decides to progress to that stage.

3 Drivers of change that impact transmission and generation investment

This chapter sets out background to the drivers of change that impact on transmission and generation investment that we will be considering as part of this 2017 review.

3.1 Coordination between transmission and generation

3.1.1 Development of the NEM

The NEM was established to introduce competition in the wholesale electricity sector with the objective of decentralising the operational and investment decisions to commercial parties who are better placed to bear the costs and manage the risks of those decisions. The focus of the developers of the NEM was to facilitate competition between electricity generators across the interconnected system and trade with retailers. Importantly, this allowed future investment in generation to be determined by market participants on the basis of signals from the market: expectations of future spot prices and retailers' willingness to enter into contracts to hedge against future price risk. Therefore, investment in generation assets in the NEM is intended to be market-driven taking into account - amongst other things - expectations of future demand, the location of the energy source, access to land and water and proximity to transmission.

A related, but distinct issue to how investment decisions in generation are made, is how scarcity of transmission capacity is managed and how transmission investment decisions are made. The provision of transmission infrastructure is very costly, and the costs of the additional investment could exceed the costs that result from the congestion (i.e., scarce transmission infrastructure). In other words, the most efficient level of congestion is not zero. This need to efficiently balance transmission investment against the costs of congestion has long been recognised in the NEM. The current processes for doing this have relied upon regulatory and institutional arrangements, such as, various forms of central planning.

Transmission network service providers (TNSPs) have statutory obligations to maintain reliability of supply to end-users. They are subject to ex ante incentive-based regulation and undertake an economic cost-benefit test to help decide what investments to make. These measures encourage the TNSPs to plan and operate their networks to meet their reliability obligations at least cost. 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 a cost-benefit test. See Box 3.1 for further discussion of the TNSPs' planning and investment decision making frameworks.

Box 3.1 TNSPs' planning and investment decision making frameworks

TNSPs are required to plan to meet jurisdictional reliability standards. In particular, Part B of Chapter 5 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 ten-year planning horizons. 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 the regulatory test for transmission (RIT-T). The RIT-T considers the benefits to generators, consumers and network businesses of a particular investment.

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; and
- providing transparency on network planning activities to enable stakeholder engagement with those activities in order to support the efficient investment in the network.

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 a cost-benefit test. Any investments are funded from revenue received from consumers.

The planning and investment framework supports an 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 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 revenue allowance is set by the AER on an ex ante basis. In determining the revenue allowance, the AER projects the revenue requirement of a business to:

- cover its efficient costs of reliably supplying customers (including operating and maintenance expenditure, capital expenditure, asset depreciation costs and tax liabilities); and
- provide an appropriate return on capital.

The TNSP's maximum allowed revenue is recovered through transmission use of system (TUOS) charges to consumers. No generator charges are imposed for using the shared transmission network.

Finally, TNSPs are responsible for assessing all new generator and load connections against the requirements of the NER, and providing the assets that are necessary to connect these parties.[6]

The most recent version of this cost-benefit test, the Regulatory Investment Test for Transmission (RIT-T), was implemented in August 2010.[7] Under the RIT-T, TNSPs are required to assess the efficiency of proposed augmentation investment options (that exceed $6 million) by estimating the benefits that would result for market participants and consumers, and comparing these to the associated costs. If a proposed investment passes the criteria governing the RIT-T, the TNSP will proceed with the investment, and this will be funded by market customers through transmission use of system (TUOS) charges.

While there are processes to review TNSPs' application of the RIT-T, to the extent that costs and benefits are forecast inaccurately, then these risks are born in full by consumers: the risks between owners of TNSPs and consumers may not be aligned in these processes.

The benefits assessed under the RIT-T relate to considering those benefits accruing to all those who produce, consume and transport electricity in the NEM. Accordingly, some of the benefits include those accruing to generators, such as differences between: capital costs; fuel consumption; and operational and maintenance costs. TNSPs consult publicly under the RIT-T process, partly in order to test their identification of the likely costs and benefits, providing the opportunity for generators to input information. Historically, such assumptions about benefits were relatively easy to predict (e.g., there were few non-network options, and typically generation located close to its fuel source), and so the process by which TNSPs assessed the benefits was not tested to any great degree.

3.1.2 Effects on transmission and generation investment

Historically, the consequences of whether or not transmission and generation investment was coordinated were less material. Significant investment in generation and transmission occurred prior to the NEM start and was driven by governments or government utilities making investment decisions (i.e., before the above arrangements were put in place).

6 Aside from in Victoria, where AEMO is responsible for assessing all new generator and load connections against the Rules requirements, but is not responsible for providing the assets associated with connection. The assets associated with connection are provided by a supplier of the asset owners' choice.

7 The COAG Energy Council has recently completed a review of the RIT-T. Broadly, the review found that the RIT-T in its current form remains the appropriate mechanism to ensure that new transmission infrastructure in the NEM is built in the long-term interests of consumers. See: http://www.coagenergycouncil.gov.au/publications/review-regulatory-investment-test-transmission-rit-t

As noted above, since NEM start, investment in transmission is typically undertaken by TNSPs in order to make sure that consumers have a reliable supply of electricity, and so historically transmission investment occurred to meet changes in consumers load i.e., increases in consumer demand. In July 2015, uncertainty around carbon policy and declining demand had reduced the number of RIT-Ts and investments that TNSPs were undertaking. Indeed, a number of RIT-Ts were actually halted due to forecasts that projected lower demand, not higher.[8]

However, going forward, we are starting to see an upwards trend in the number of RIT-Ts being undertaken, and a need for TNSPs to assess greater changes in the potential pattern of generation in the NEM.[9]Four RIT-Ts have been announced in the last year or so, compared with none in the previous years.[10] Technological developments, along with various state-based renewable energy policies, mean that predicting what (if any), and where, transmission infrastructure should be built is becoming more challenging for example, assumptions about relative generation costs become harder as the amount of technologies multiply. It is worth noting that we are also starting to see a trend of TNSPs seeking more information to assist them in the RIT-T process from interested parties (e.g. generators, non-network providers, demand management providers etc) on an informal basis prior to starting the formal RIT-T process that is set out in the NER.[11]

3.1.3 Impacts on coordination

As uncertainty regarding transmission and generation investments increases, in order to have efficient outcomes for consumers, transmission and generation investment needs to be coordinated. Any difference in the process by which generation and transmission investment occurs has the potential to result in development paths that do not minimise the total system cost faced by consumers. The question is how best to achieve this coordination. A key issue is the degree to which the allocation of risks between owners of the TNSPs and consumers are aligned in these processes. Efficient coordination of transmission and generation investment typically requires:

- information being exchanged between the generation and transmission sectors;
- that information being accurate and meaningful to the recipients; and
- investment decisions by each generator and TNSP incorporating this information and being efficient in light of that information.

8 See appendix A, which details that between 2011 and 2015, eight RIT-Ts were halted due to revisions in load forecasts being lower than anticipated.

9 The Commission is also considering a rule change request that would, amongst other things, amend the NER to extend the application of the RIT-T to replacement projects. See: http://www.aemc.gov.au/getattachment/7cedb6a4-5e55-442c-9718-73528703f062/Consultation-paper.aspx

10 See appendix A for further details.

11 See AEMO's request for information for the Western Victoria Thermal Capacity RIT-T; and the additional papers that have been published as part of ElectraNet's RIT-T on South Australian Energy Transformation. See also the analysis contained in appendix A.

Efficient coordination between the sectors contributes 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; and
- parties that make investment decisions have a direct financial stake in the efficiency of outcomes resulting from these decisions.

This is consistent with a fundamental principle underpinning the development of the NEM, about decentralising the operational and investment decisions to commercial parties who are best placed to bear the costs, and manage the risks of those decisions. The risks associated with transmission investment include the risk associated with demand projections resulting in a different level of investment than is required, and the risk of supply-side changes resulting in higher costs of some generation types and obsolete investments. Currently, since consumers pay for all of the TNSP's maximum allowed revenue, consumers also directly bear most of the costs associated with transmission. This allocation of risk becomes more important in an uncertain or changing environment, as the risks associated with transmission investment increase.

For example, if a regulated planning approach delivers a transmission path that is significantly different from that required by competitive investment in generation, then a different generation pattern could emerge, despite the TNSP's investment. There is a risk that the transmission assets that the TNSP has invested in would be underutilised, and that alternative transmission assets would need to be built (and paid for by consumers). Consumers, who bear most of the risk of the higher system cost, have only limited ability to influence future decisions, and not much information or expertise regarding relative costs of different combinations of generation and transmission. Currently, TNSPs rely on the transparent nature of the RIT-T process, including information received from generators and demand side participants, in this process to inform their planning and investment decisions.

The absence of a direct price signal for generators related to transmission may result in locational decisions that increase the overall costs of transmission and generation. For example, proximity to a gas pipeline is likely to be important to a gas-fired generator, but currently that generator would not be exposed to the full cost of electricity transmission investment that may be required to support its locational decision. This could mean that generation and transmission is not co-ordinated as well as it could be.[12]

12 As discussed in section 3.1.1, TNSPs have statutory obligations to maintain reliability of supply to end-users. If a reliability standard is not met, then the TNSP must undertake a cost-benefit test (including assessing the costs and benefits accruing to all those who produce, consume and transport electricity in the NEM) to assess what can be done to meet the standard. Therefore, based on the TNSP’s cost-benefit test and associated assumptions, a TNSP may build new network capacity between an existing generator’s location and the demand. However, as explained further in section 3.1.1, this is done through a separate process to generation investment.

3.1.4 Implications for the future

Transmission and generation investment in the future may look quite different from the past. Therefore, improvements to current arrangements become more critical in the future if:

- the diversity of location and operating type of generators change. For example, this could occur if there are more types of renewable generation, entering the NEM or more generation is integrated with storage or other new technologies;
- demand patterns change, or change in a way that is not easy to predict; or
- relative network costs become less predictable, for example, as the cost of gas changes, what the relative cost of gas transmission is compared to electricity.

The potential for such changes would make it harder for the TNSP to make assumptions that underpin a 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. Such trends are considered in more detail in the following chapters.

Given that this assessment would become more difficult for the TNSP, it would be preferable to have commercial entities making decisions on the best combination of generation and transmission to meet demand, especially given their own knowledge of their own costs, and the incentives.

The philosophy that generation decisions should drive transmission investment is a fundamental philosophy underpinning the discussion in the rest of the paper. The Commission welcomes feedback from stakeholders in relation to this conclusion.

3.1.5 Timing impacts

While there may be temporal differences between the time taken to build transmission investment, versus generation investment and so which type should 'drive' the other, it is difficult to draw strong conclusions about this, based on the timing of construction. Solar and wind farms can be constructed much more quickly than gas or coal fired power stations. However, the actual timing of various investments depend on a range of matters including how projects are financed, how easy it is to obtain environmental approvals, and the connections process undertaken by the TNSP. For example, in January 2012 the ACT government held Australia's first solar auction, and awarded feed in tariffs to three solar farm projects to be located in the ACT. These solar farms have progressed on different time scales, reflecting the difficulty in estimating timeframes for the build of such assets:

- the Royalla Solar Farm was commissioned in late August 2014, and officially opened in September 2014;[13]
- the Mugga Lane solar farm, who had its project awarded in August 2013, and officially opened in March 2017; and

13 See: http://www.environment.act.gov.au/energy/cleaner-energy/large-scale-solar

- the One Sun solar farm, had to move its location after plants to build it in a previous location met fierce local community opposition and so did not receive the necessary approvals at that site, and is currently under construction at the new location.[14]

3.2 Why are we considering drivers of change?

Given the above, in the face of current significant change and uncertainty in our energy markets, introducing more commercial drivers on TNSPs, and more commercial financing of transmission investment, should, in theory, help in better allocation of risks and a closer alignment of generation and transmission investment.

Australia's energy system is currently undergoing a revolution. Changes are increasingly driven by new technologies, business models and consumer preferences, but also by various sector specific government schemes that operate outside the governance frameworks of the NEM, and that are usually designed to support renewable technologies or reductions in emissions. Recent years have seen a much more rapid transformation of the sector. New ways of generating electricity are challenging the physical security of the electricity system, and consumers are demanding more choice in the way they source and use electricity. This means that the sector and the regulatory framework underpinning it must be more flexible. It also means that policy objectives must be clear and the mechanisms used to achieve them aligned and integrated.

Given the current level of policy uncertainty and significant changes currently occurring in the energy markets, the Commission considers it is important to be prepared for the future, and introduce significant changes when they are needed and can be most effective. Investments in technologies to maintain a reliable and secure system are crucial, and regulatory frameworks should set the pre-conditions, but not target specific technologies, so the market can coordinate and deliver outcomes in the most efficient way possible. Market and technological risks should be allocated to the parties with the strongest incentives and abilities to manage or mitigate those risks. This protects consumers from bearing the costs of mistakes.

Therefore, in assessing whether or not there warrants investigation to change existing transmission frameworks, we need to consider whether the underlying drivers of transmission and generation investment have changed from those that existed at the time the NEM was developed. Examining the *drivers* of various projections to the future of generation and transmission investment is beneficial, since it avoids the need to examine projections or forecasts themselves, which are, by definition, always wrong.

Therefore, the drivers that are set out in the following chapters, and which the Commission has been requested to consider under the terms of reference, can be characterised in the following way:

- **Government policies and regulations and international agreements**, for example, environmental, carbon pricing or other carbon emissions reduction policies, as well as other influences that result in major load retirements are

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14 See: http://reneweconomy.com.au/69780/; http://citynews.com.au/2015/corbell-gives-up-on-uriarra-solar-farm-aims-for-williamsdale/

considered since such drivers have the potential to fundamentally alter the incentives around generation and transmission investment, potentially shifting the typical technology and location of generation infrastructure that is installed. These are discussed in more detail in chapter 4;

- **Technological developments**, **the establishment and penetration of new business models**, the **level of distributed generation** and the **level of variance in forecasts** since such drivers could potentially change the use of the transmission network. The future could involve high levels of distributed energy resources; or, conversely, there may be more use of new technologies for grid-scale renewable generation, storage and transmission network investment. These are discussed in more detail in chapter 5; and
- Other drives, such as developments in the **wholesale market** and **NEM rule and regulation changes**, which can also impact on transmission and generation investment are discussed in more detail in chapter 6.

4 Government policies, regulations and international agreements

This chapter discusses the driver of government policies, regulations and international agreements in more detail. Specifically this chapter will focus on how government policies can impact on transmission and generation frameworks, developments in government policy more generally and also prospects for the future.

4.1 Introduction

This chapter will focus mainly on environment and emissions reduction policies as these directly impact on investment in generation. We welcome feedback on whether there are any other government policies, regulations or international agreements that should be considered.

In discussing this driver it is important to understand how government policies, such as emissions reduction policies, impact on generation and transmission investment. The specific design of an emission reduction policy mechanism will determine how it interacts with the energy market and, in turn, will determine how generation and transmission investment will be impacted by the policy.

This chapter will also discuss the current policy environment and describes expected developments in the future.

4.2 Base case policy environment

This section outlines the government environmental policies that were in place in July 2015. This is the "base case" for the purposes of this reporting and any developments in recent years will be assessed against these base case policies.

Since July 2014 the 'Direct Action Plan' has been the principal component of the Australian Government's climate policy. Direct Action comprises the $2.55 billion Emissions Reduction Fund and the Safeguard Mechanism.[15] This plan was brought in to replace the Carbon Pricing Mechanism introduced by the previous government. The aim of these new policies was to meet Australia's commitment under the Copenhagen Accord of reducing carbon emissions by 5 per cent from 2000 levels by 2020.

Direct Action is made up of two pillars, the Emissions Reduction Fund (ERF) and the Safeguard Mechanism:

- The ERF is an abatement procurement mechanism designed to promote least-cost abatement from the private sector. This is achieved through a reverse-auction mechanism through which project proponents submit bids to supply a quantity of abatement for a nominated price.
- The Safeguard Mechanism is the second pillar of the Direct Action Plan. While it had been announced in July 2015, it only came into effect on 1 July 2016. This

15 See http://www.environment.gov.au/system/files/resources/c42c11a8-4df7-4d4f-bf92-4f14735c9baa/files/factsheet-australias-2030-climate-change-target.pdf

policy sets baselines for large emitters to make sure that emissions do not increase beyond these baseline levels.

The Large-scale Renewable Energy Target (LRET) is another government environmental policy that was in place in July 2015. The LRET is a traded certificate system that provides an incentive for additional electricity generation by 2020 from large-scale renewable energy sources.

In June 2015, after a period of uncertainty regarding the level of the target, the LRET was reduced to 33,000 GWh, down from the previously legislated 41,000 GWh. The agreement on the new level of the target was a result of a period of extended negotiations between Australia's two main political parties. It was agreed at this time not to review the target again until 2020.

4.3 Current environment

Under the Paris Agreement,[16] Australia has committed to reduce emissions by 26-28 per cent of 2005 levels by 2030. Policies that are currently in place to meet these government-set targets include the Renewable Energy Target and Direct Action, as described above.

In recent years, numerous changes to government environmental policies have led to uncertainty, which is turn is having a detrimental impact on potential investment in new generation. In order for any environmental policy to be sustainable, investors must have confidence that the policy can meet its objectives and that it is sufficiently robust to deal with changes in the market.

Submissions by energy market participants to the Chief Scientist's Independent Review into the Future Security of the NEM emphasise the need for policy certainty.[17] AGL's submission outlines three actions that need to be taken to support an orderly energy market transition. One of these key actions is, according to AGL, "supporting investment certainty in a carbon constrained future".[18] Origin Energy's submission notes that the current lack of a long term approach to setting sustainable emissions reduction policies in the energy sector is "threatening to undermine future investment and potentially market efficiency".[19]

In December 2016, the Commission published advice on the integration of energy and emissions reduction policy. This advice discusses characteristics that emissions reduction policies should have in order that both the emissions reduction and energy market objectives can be met. One of the criteria used to assess different policies was the "adaptability and sustainability of scheme design". This criteria relates to the need for

16 The Paris Agreement seeks to build on previous international agreements on climate change. Its central aim is to strengthen the global response to climate change. Under the Paris Agreement, all parties put forward "nationally determined contributions" to emissions reduction and a commitment to strengthen these efforts in the years ahead.

17 Submissions are available at http://www.environment.gov.au/energy/national-electricity-market-review/submissions

18 AGL, Submission to the Independent Review into the Future Security of the NEM,p.2.

19 Origin Energy, Submission to the Independent Review into the Future Security of the NEM,p.9.

investors to have certainty and confidence regarding environmental policy in order to invest.

Investors need to be confident that any emissions reduction mechanism can yield predictable outcomes given different market conditions and policy objectives. Without confidence that a policy mechanism is resilient investment will not be forthcoming and it is likely that neither the emission reduction nor wider energy market objectives will be met.[20]

4.3.1 How government policies can impact on generation investment

The type and design of the specific emissions reduction policy mechanism chosen will have a different impact on wholesale prices, costs of generation and therefore investment in generation and the resulting generation mix.

Therefore, clarity on what emissions reduction policy mechanism is going to be in place over the medium to long term is needed to accurately predict the effect of government's environmental policies on the generation sector. It is also important to recognise that certainty of a policy is important; it is only when a policy is regarded as 'adaptable and sustainable' that investment certainty will be promoted.

The box below provides detail on how different types of emissions reduction policies can impact on generation investment.

Box 4.1 How different emissions reduction policy mechanisms impact on generation investment

In December 2016, the Commission published advice on the integration of climate and energy policy. In this advice, the characteristics of three different types of emissions reduction policies were discussed. The types of policies reflect the policy levers available to governments to achieve emissions reductions in the energy sector. Broadly, these policies can be classed as: market based; technology subsidy; and government intervention.

For each of these types of policies there are numerous policy instruments that could be chosen. For the purposes of this discussion, we are not focusing on any particular policy mechanism but rather how different types of policies interact with the wholesale market and therefore have differential impacts on generation investment.

Market-based emission reduction policy mechanisms

This category of emissions reduction policies works by changing the relative cost of different generation technologies. That is to say that the most emissions-intensive generation types face an increase in costs and this makes them relatively more expensive than low or zero emissions generation. The change in relative costs in generation technologies results in a shift in the generation merit-order. In other words the market-based policy would shift the relative cost of generation, by pricing carbon at a level to meet the emissions reduction target.

20 AEMC, Integration of energy and emissions reduction policy, Final Report, p v.

A market-based policy is technologically-neutral as only the emissions intensity of the generator, rather than a specific technology, determines a generator's obligation. A technologically-neutral policy allows for fuel switching from emissions-intensive brown and black coal to gas and renewables. This has implications for generation investment because less new capacity may be needed under a market-based policy, relative to other emissions reduction policies, as the emissions reduction target can be met by increasing output from existing gas plant as well as new gas and renewable investment.

Technology subsidy emission reduction policy mechanisms

These policies achieve emissions reductions by providing a financial subsidy to certain low emissions generation technologies. The current Large-scale Renewable Energy Target (LRET) is an example of one such technology subsidy emission reduction mechanism. Under this mechanism, eligible renewable generators create certificates based on their generation output which they can sell to retailers. Retailers are obliged to purchase and surrender a certain number of renewable energy certificates. The current target is 33,000 MWh.

A technology subsidy type policy is, by definition, not technologically-neutral. The design of the policy may vary in terms of which technology types are eligible to receive the subsidy. The availability of the subsidy may be an important factor in determining what types of new generation are built.

Also, the amount of new generation needed to meet demand may be higher under a technology subsidy policy. This is because the policy incentivises the entry of low-emissions generation to the wholesale market. This new generation is not responding to the traditional investment signals provided by the market but rather the availability of the subsidy. The entry of new generation therefore may not be necessary to meet demand in the short term. Over the longer-term the fall in wholesale prices is expected to cause the exit of emissions-intensive thermal generation but this may take time to occur.

Government intervention to achieve emissions reduction

Finally, governments can intervene in energy markets to bring about a reduction in emissions. An example of such a policy is governments directing an emissions-intensive power station to close or enforcing the closure of power stations through regulations.

These policies directly close power stations and therefore require that new generation enters the market to replace the capacity that has exited. Government intervention to close power stations allows for fuel switching between coal and gas. This means that under such policies new generation may be in gas or renewables.

These policies may also affect generation investment by embedding a barrier to exit in the market. If generators expect payment or other compensation for closure they may delay their decision to close and remain in the market for longer than they would have in the absence of the government policy. This may delay the entry of new generation in the market.

The discussion in Box 4.1 above shows that emissions reduction policy mechanisms impact on the technology and amount of new generation investment. The location of generation investment can also be impacted by government emissions reduction policy.

Three Australian jurisdictions, ACT, Victoria and Queensland, have implemented or proposed state-level renewable energy targets. These state-based schemes can also impact on the location of generation investment. These policies can impact on the location of investment in two ways. First, as discussed below, renewable generation have an incentive to locate near renewable resources, that is, in 'sunny' or 'windy' locations. Second, the design of these schemes can impact on the location of investment. Some state-based renewable energy targets may require or encourage projects to be located within the state in question, or even in particular parts of the state.[21] This means that the decision of where to locate is not decided by where in the NEM is most efficient but rather by the design or objectives of the state-based renewable energy target. This is discussed in more detail in the next section.

Given the current uncertainty around what additional government policies, if any, will be in place to meet the Government's 2030 emission reduction target, it is not possible to accurately predict how generation investment will be impacted.

4.3.2 How government policies can impact on transmission investment

The above discussion illustrates that, regardless of the emissions reduction policy chosen, government environmental policy will impact on investment in electricity generation. This, in turn, has impacts for transmission investment. Investment in the transmission network will be needed to facilitate and support the transition of the electricity sector to a lower emissions future. This is because there is a difference in where renewable generation needs to locate relative to where incumbent thermal generation is located. New renewable generation has an incentive to locate near renewable resources (typically at the outer edges of the grid), while the current transmission system is built around existing generation, which is often located near resources such as mines or gas pipelines. This locational mismatch may necessitate increased transmission investment to accommodate the changing generation mix.

The above section refers to state-based renewable energy targets. These policies, if they are not geographically-neutral, can directly impact transmission network investment. This is because such policies may require that new renewable investment locate within a state or area, which may cause challenges for the transmission network.

A recent example of a state government policy in Victoria illustrates this point.

21 Proposed evaluation principles for the Victorian Renewable Energy Target included: value for money; ability to contribute to economic development; electricity transmission network interactions; wholesale market participation; timely construction and operation; contribution toward Victoria's target; and community engagement. See Victorian Renewable Energy Auction Scheme, Consultation Paper, p.13.

Box 4.2 The Victorian Renewable Energy Target

The Victorian Government has set a renewable energy generation target of 25 per cent by 2020 and 40 per cent by 2040. These targets are to be met through a reverse auction scheme where renewables submit bids to the Victorian Government, who will evaluate them and choose which projects to finance.

One of the aims of the Victorian renewable energy target is to "create up to 11,000 two-year construction jobs over the life of the scheme, particularly in regional Victoria"[22], this implies that in evaluating bids the scheme will give preference to projects that are located, and therefore create jobs, in Victoria.

The design of the Victorian scheme is therefore not geographically-neutral and this creates potential issues for the transmission network in Victoria. AEMO, in its submission to the consultation process on the Victorian renewable energy target, noted that it had, in its role as jurisdictional transmission planning body for Victoria, previously noted that "parts of the Victorian grid face challenges accepting the current rate of connection interest, almost exclusively in the West of the state, and principally from wind generation".[23]

AEMO noted the Victorian transmission system is built around two backbones which are designed to connect areas of traditional generation, such as the Latrobe Valley and the Snowy Hydro scheme, to major urban centres. Other areas of the state are serviced by "a thin and sparse network, built to supply a relatively small demand across a very wide area".[24] The connection of large numbers of renewable generators on this network could lead to congestion which would require a network augmentation to resolve.

The government's evaluation of auction bids includes an evaluation principle of "electricity transmission network interactions". AEMO agree that this is an important factor to be considered when evaluating bids, but note that "estimating grid issues and future economic costs can be technical and complex".[25] This example illustrates how government policies can impact directly on the transmission network and the location of transmission investment.

4.4 Future developments

Given the large proportion of emissions from electricity, any efforts to reduce emissions economy-wide will inevitably involve transformation of the electricity generation sector. This transformation is expected to continue in the future as Australia works to meet its 2030 targets.

This year, the Department of Environment and Energy is undertaking a review of climate change policies. According to the terms of reference "[t]he Review will ensure

22 See http://www.delwp.vic.gov.au/energy/renewable-energy/victorias-renewable-energy-targets

23 AEMO, submission to Victorian Renewable Energy Auction Scheme Consultation, 31 August 2016,p.3.

24 Ibid, p.4

25 Ibid, p. 6

the Government's policies remain effective in achieving Australia's 2030 target and Paris Agreement commitments".[26] The review commenced in February 2017 and will conclude by the end of 2017. The review will take into account parallel processes, such as the Finkel review of the reliability and security of the NEM.

One of the specific items to be looked at as part of the review is "the integration of climate change and energy policy, including the impact of state-based policies on achieving an effective national approach".[27] This suggests that the role of the energy sector in reducing emissions will be a particular focus of the review. However, at this stage it is not known what new policies, if any, will be introduced as a result of the review.

Over the longer term, there is a review mechanism every five years built into the Paris commitments. This may mean that, post-2030, the ambition of emissions reduction policy targets may be increased and this would involve further change to the generation and transmission sector.

4.5 Conclusion

There have been no additional environmental policies introduced at a federal level since July 2015. Similarly, there have been no major revisions to environmental policies since this time.

However, despite the relatively stable policy settings, the amount of uncertainty regarding government environmental policies is only growing.

In order to meet Australia's international commitments under the Paris Agreement action to reduce emissions across the economy will be required.[28] As the largest single source of emissions in Australia[29] any effort to reduce emissions will inevitably involve the electricity generation sector. There is also no clarity on what, if any, policy will replace the LRET when it ends in 2020.

Without clarity on what specific policies will be put in place, the effect of government policies on transmission and generation investment is difficult to assess at this time.

26 Department of Energy and Environment, 2017 Review of Climate Change Policies, Terms of Reference

27 Ibid.

28 Department of Environment and Energy, Review of climate change policies, Discussion Paper, p.4.

29 See National Greenhouse and Energy Reporting at http://www.cleanenergyregulator.gov.au/NGER/National%20greenhouse%20and%20energy%20reporting%20data/Data-highlights/2015-16-published-data-highlights

5 Technological developments and new business models

Four of the drivers of transmission and generation investment that the Commissions has been requested to consider are discussed in this chapter. These are:

- technological developments;
- the development of new business models;
- the level of distributed generation; and
- the level of variance in forecasts of electricity demand.

Each of these four drivers relate to how the market may change and adapt in the future in the face of *technological developments*. These changes to the market may include: a change in the generation mix, as a result of changes in the relative costs of different generation types; the development of new business models to take advantage of new opportunities from technological changes; and increased take-up of distributed generation. The accuracy of forecasts of electricity demand is also discussed as this is also affected by technological developments.

These drivers are closely related and impact on one another so it is appropriate to discuss them together.

5.1 Technological developments

This section will describe technological developments since July 2015, the current environment and expected future trends. The discussion will focus on the fall in costs of different technologies, the expected take-up rates of these technologies and also how the expected technological developments may have an impact on the generation mix going forward.

5.1.1 Base case

According to the 2015 Electricity Statement of Opportunities (ESOO), the installed capacity of the NEM comprised 54 per cent coal, 24 per cent gas, 6 per cent wind, 17 per cent hydro and less than one per cent from other sources.[30] This document also reported that 1,078 MW of capacity was withdrawn and 1,074 MW of new generation was in operation since the 2014 ESOO. All of the capacity withdrawn from the market in 2014-15 was thermal base-load generation, while all of the new entrant generation was either large scale solar (122 MW), large scale wind (946.4 MW) or gas (6 MW).[31]

5.1.2 Current environment

The trend of the entry of intermittent generation and the exit of older, higher-emissions base-load generation has continued since July 2015. In the 2016 ESOO, AEMO report that 705 MW of new intermittent generation had been committed since the 2015 report.[32] AEMO is also tracking 19,102 MW of proposed[33] new generation capacity.

30 AEMO, Electricity Statement of Opportunities 2015, p.11

31 Ibid, p.13

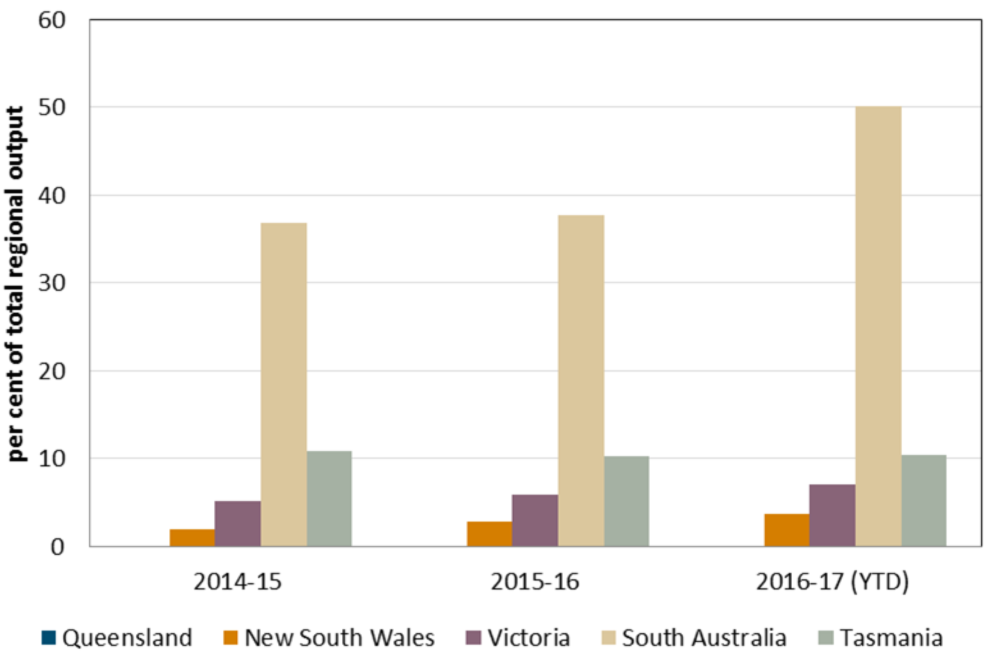
32 AEMO, Electricity Statement of Opportunities 2016, p. 17.

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. These projects are not included in AEMO's forecasts in 2016 as they are not at a sufficiently advanced stage.[34]

Since July 2015 there have been two significant exits from the generation market. Northern Power Station in South Australia was withdrawn from the market in May 2016. Hazelwood Power station in the Latrobe Valley in Victoria was closed in March 2017. The closure of Northern power station made South Australia more reliant on local wind generation and, in times when the wind is not blowing, on imports from Victoria. It is too early to assess the impact of the closure of Hazelwood on the market, though initial indications are that it will impact transmission flows across the interconnectors between Victoria, New South Wales and Queensland.[35]

Wind is currently the lowest cost large scale renewable technology and so investment in new, large scale, renewable generation has, so far, been concentrated in wind energy.[36] The amount of wind generation capacity as a per cent of regional output has increased in every state in the NEM, except Queensland, since 2014-15. The most dramatic increase has been in South Australia, where wind generation as a percentage of total regional output has increased from 35 per cent in 2014-15 to 50 per cent so far this year. This growth is shown in Figure 5.1.

Figure 5.1 Wind generation output as percentage of total regional output



Source: AER wholesale market statistics

Another factor that will determine new generation investment is the costs of renewable generation technologies relative to each other. The cost of large scale solar is expected to

33 'Proposed' includes publically announced and advanced projects only.

34 Ibid, p.17

35 AEMC, 2016 Residential Electricity Price Trends, final report, 14 December 2016, vii

36 Clean Energy Council, Clean Energy Australia Report 2015, p.8

decrease[37] over the coming years, making it more competitive with wind. This, coupled with the fact that there are many areas with good solar resources that are not yet developed, may mean that investment in large scale solar will increase in the future.[38]

Given the relative costs of renewable technologies, with wind and solar currently the most cost effective renewable technologies, the vast majority of renewable generation currently in the market is intermittent.

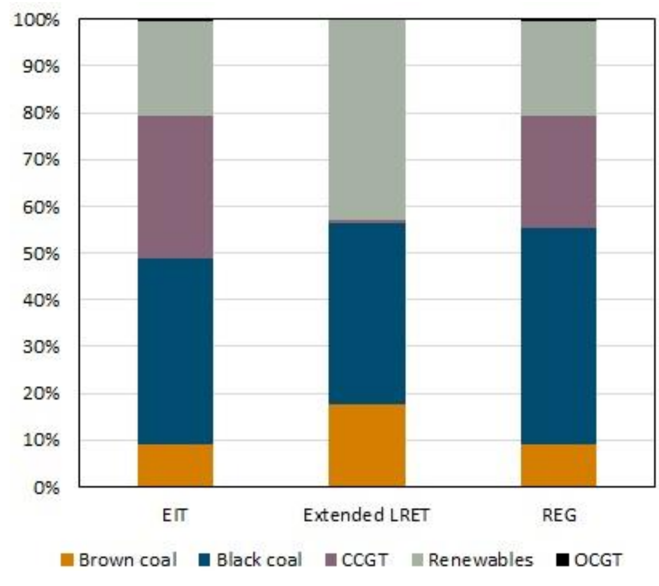
5.1.3 Future developments

There is still a large degree of uncertainty regarding the technology mix and location of future generation investment. This, in turn, creates uncertainty regarding transmission investment.

As noted in chapter 4, there is still a large amount of uncertainty regarding government environmental policy. In December 2016, the Commission published advice on the integration of energy and emissions reduction policy. As part of this advice, three scenarios were modelled representing three policy options for achieving emissions reductions that are available to government. These policy options were: a market-based, emissions intensity target; a technology subsidy in the form of an extension of the current large-scale renewable energy target (LRET); and government regulation in the form of a regulated closure policy for high-emissions power stations.

The output mix modelled under each of the three scenarios described above is shown in Figure 5.2. The output mix results show how much generation, on average, comes from different generation technology types under each emissions reduction policy mechanism. This chart shows that, depending on the emissions reduction policy mechanism in place, the resulting output mix is very different.

Figure 5.2 Average output mix, 2020-2030 as a percentage of total output



Source: Frontier Economics, *Emissions reduction policy options,* A report prepared for the Australian Energy Market Commission, November 2016.

37 ARENA, Advancing solar in Australian through RD&D investment, Final Report, p. 4.

38 Powerlink, Transmission Annual Planning Report 2016, p.130.

It is likely that the share of lower emissions generation, including gas and renewables (the majority of which are expected to be intermittent), will grow as the sector works to reduce emissions if sustainable environmental policies are in place. However, as the above graph demonstrates, the future fuel mix and therefore generation investment, is dependent on the environmental policy in place.

As a consequence of the uncertainty around future generation investment as a result of changes in the relative costs of technologies as well as uncertainty regarding future environmental policies, the effect of technological developments on transmission and generation investment is difficult to quantify at this time.

5.2 Establishment of new business models

Given that new technologies are developing it follows that new and innovative business models will be needed to harness the capabilities and to maximise the value of these technologies for market participants. Given the uncertainties that currently exist as to which technologies will become a feature of the energy market in the future, there is also a large amount of uncertainty regarding changes to business models in the future.

5.2.1 Base case

The uptake of new, distributed technologies in Australia's electricity sector is having an impact on the way consumers have traditionally been supplied with and use electricity. Such technologies enable consumers to generate electricity in the distribution system, providing capabilities such as local generation, load shifting and load reduction. Distributed energy resources and new business models to fully utilise these resources have the potential to bring substantial benefits to consumers in terms of the cost of, and choice in, their energy service offerings.[39]

Given the potential for technological advancement new business models would be expected to have some of the following attributes:

- adapt to the technical challenges associated with integrating new technologies into the energy market;
- develop methods to aggregate energy services provided by households and other smaller, distributed entities;
- develop platforms, that do not currently exist, for trading of new energy services; and
- allow households and other consumers to provide services to the grid and to allow networks to source non-network solutions from a wider range of sources.

In July 2015, new business models were starting to emerge and this trend has only continued to grow in the intervening period.

5.2.2 Current environment

There are currently a number of examples of new and innovative business models in operation in the NEM. These new business models perform different functions for

39 AEMC, Distribution Market Model, Approach Paper, p.7.

customers and try to unlock value from distributed energy resources in different ways. Given that the deployment of distributed energy resources, such as batteries, is still nascent, many of these new business models are still at trial stage or are in receipt of funding or other support to test their business model.

The first example shows how energy services companies are aiming to optimise consumers' energy use. Reposit Power is an energy services company that provides software to optimise the performance of a home battery system. The software uses machine learning to combine information about the household's energy consumption patterns with expected solar generation based on weather forecasts, in order to maximise self-consumption and minimise bills. Secondly, at times of high wholesale prices, the Reposit software will sell surplus energy back to the grid, enabling households to maximise the economic return from owning battery storage.

New business models can also aggregate the functionality of a network of household and business-owned battery storage systems, in order to provide services such as peak demand management and frequency control. An example of such business models is the AGL Virtual Power Plant (VPP) trial, partially funded by ARENA.[40] AGL states that the Adelaide-based trial, which uses cloud-connected software developed by the US company Sunverge, has already successfully linked more than 60 batteries, which together have stored and delivered over 10,000 kWh. Ultimately, the aim is to create a total of 7MWh of storage capacity and 5MW peaking capacity. This trial shows that the aggregation of distributed energy resources may have the potential to provide an alternative to large-scale and medium-scale generation.

Another innovation in business models is to allow households and small businesses to trade their excess generation from rooftop photovoltaic (PV) with other individuals. In order to facilitate this type of trading, a trading platform has to be developed. An example of such innovation is Power Ledger, a West Australian startup.[41] This company is seeking to set up peer-to-peer energy trading for households and businesses with solar panels. Households that generate energy surplus to their own requirements will be able to sell it to other consumers - at a higher rate than the typical feed in tariff, but cheaper than the typical retail electricity price. If more electricity is generated and traded through the distribution network, there may be reduced need for transmission investment.

5.2.3 Future developments

As previously stated, the development of new and sustainable business models is largely dependent on the uptake of distributed energy resources, such as rooftop PV and storage systems. This is discussed in more detail in the next section.

Without further information on what technologies will be adopted and at what rate it is very difficult to predict what new business models will succeed in the energy market and what impact these new business models will have on transmission and generation investment.

40 See https://arena.gov.au/project/virtual-power-plant/

41 See https://powerledger.io/

The AEMC is undertaking a 'Distribution Market Model' project to explore how the operation and regulation of electricity distribution networks may need to change in the future to accommodate an increased uptake of distributed energy resources such as rooftop solar systems, battery storage and electric vehicles. This project forms part of the AEMC's technology work program.[42]

5.3 Level of distributed generation

This section describes the level of distributed energy generation in the NEM in 2015 and currently. The primary type of distributed energy installed in the NEM is rooftop PV and so this will be the focus of the discussion. In the future, there is the potential for battery storage to play a larger role in the energy market and so forecasted take-up of storage is also discussed.

5.3.1 Base case

In July 2015, rooftop PV was predominantly concentrated in the residential sector. In 2014-15 it was estimated that 1.5 million, or 25 per cent of, households in Australia had installed small scale solar systems. The total installed capacity of rooftop PV was 3,700 MW, equivalent to 8 per cent of total installed capacity in the NEM in 2014-15. In the same year, rooftop PV supplied 2.7 per cent of electricity requirements in the NEM.[43]

The rate of installation of rooftop PV differs by region. South Australia has the highest penetration of rooftop PV installations, with 7 per cent of the state's annual energy requirements in 2014-15 coming from rooftop PV.[44]

5.3.2 Current environment

The rates of rooftop PV have continued to increase since 2015. In its 2016 National Electricity Forecasting Report, AEMO predict that rooftop PV generation will continue to increase and will reach 14 per cent of operational consumption in the NEM by 2035.[45]

In the current environment of increasing generation from rooftop PV, AEMO are considering the effect of this development on demand going forward. Rooftop PV output is measured as a reduction in demand by AEMO (as it is generation that is not supplied by the grid) and largely because the increase in distributed generation, it is expected that grid demand will remain relatively flat until 2035-36.[46] In addition to the effect on the level of grid demand, rooftop PV also impacts on the timing of demand. It is forecast that the increased penetration of rooftop PV will shift minimum demand from overnight to midday, when the sun is strongest. This is already the case in South Australia.[47]

42 More information is available from the AEMC website at http://www.aemc.gov.au/Markets-Reviews-Advice/Distribution-Market-Model#

43 AER, State of the Energy Market 2015, p. 30.

44 Ibid, p.30.

45 AEMO, National Energy Forecasting Report 2016,p.28.

46 Ibid, p.17

47 Ibid, p.26.

There is the potential that the combination of batteries with rooftop PV will ameliorate the minimum demand issues discussed above. By combining rooftop PV with a battery, excess solar energy created during the day when demand is lower could be stored and used during evening peak periods. If the penetration of such small scale generation and storage installations is high, it may reduce the need for large scale, transmission-connected generation investment. This is because grid demand may decrease as more of household demand could be met by their own generation. There is also the potential the new business models and energy service providers will provide consumers with the opportunity to optimise how they use their in-home energy generation and storage units.

5.3.3 Future developments

As discussed above, Australia is the world leader in rooftop PV penetration. Forecasts from Bloomberg New Energy Finance predict that rooftop PV will continue to grow strongly. The continued growth for rooftop PV is expected to be driven in the near term by the commercial sector, with a surge in adoption by industrial users in the 2020s. In the residential sector, installation is expected to continue at current levels. By 2040, the forecast for behind-the-meter PV capacity in Australia is 44 GW. In 2040, 23 per cent of electricity demand is expected to be met by rooftop PV.[48]

For storage, it is likely that the cost of storage systems will decrease significantly and that uptake will increase. The timing of these developments is still some way off however. Bloomberg New Energy Finance forecast that payback periods for storage systems will exceed 10 years until the early 2020s, with only 106,000 storage systems installed by 2020. By 2030, the number of storage systems installed is expected to reach 1 million.[49] By 2040 there is projected to be 37 GWH of behind-the-meter storage capacity in Australia.

Over the longer-term, distributed energy has the potential to become ubiquitous, and the ongoing uptake is projected to keep grid supplied demand relatively flat to 2040.[50] This has a direct impact on the amount of new generation investment needed in the market. In turn, the need for investment in transmission networks may also be reduced as the level of distributed energy resources increases. The future may involve high levels of distributed energy resources. Or, there could be more use of new technologies for grid-scale renewable generation, storage and transmission network investment.

5.4 Variance in forecasts

This section discusses demand forecasts and in particular the challenges faced in forecasting demand going forward. Given that official forecasts are annual exercises, and the reference period for this reporting is from July 2015, there has only been one update to AEMO's forecasts in the period of review. Therefore this section does not seek

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

49 Ibid, p. 21

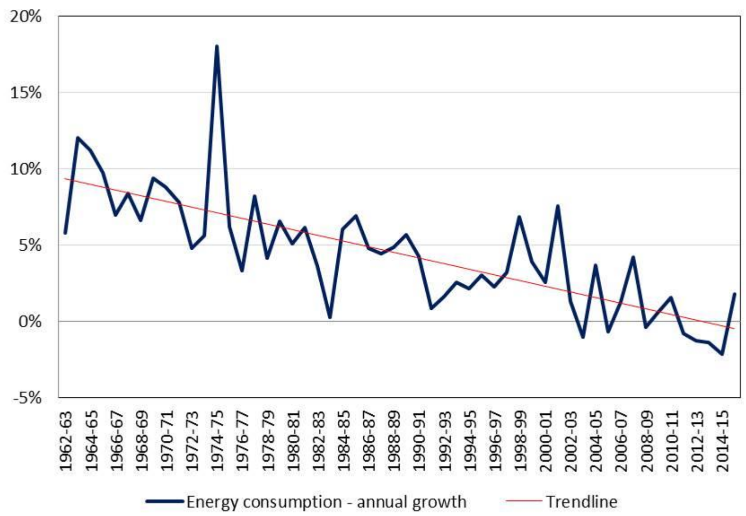
50 Ibid, p.21

to compare the base case to the current environment but rather provides background on demand forecasts and discusses future issues.

5.4.1 Background

The growth of energy consumption in the NEM is falling, as shown in Figure 5.3. There are numerous causes of this decline in consumption growth including the transition of Australia's economy from primary industry and manufacturing to less energy-intensive service industries, the increased uptake of distributed energy such as solar PV and improvements in energy efficiency.

Figure 5.3 NEM-states annual energy consumption growth rate, 1960-61 to 2014-15



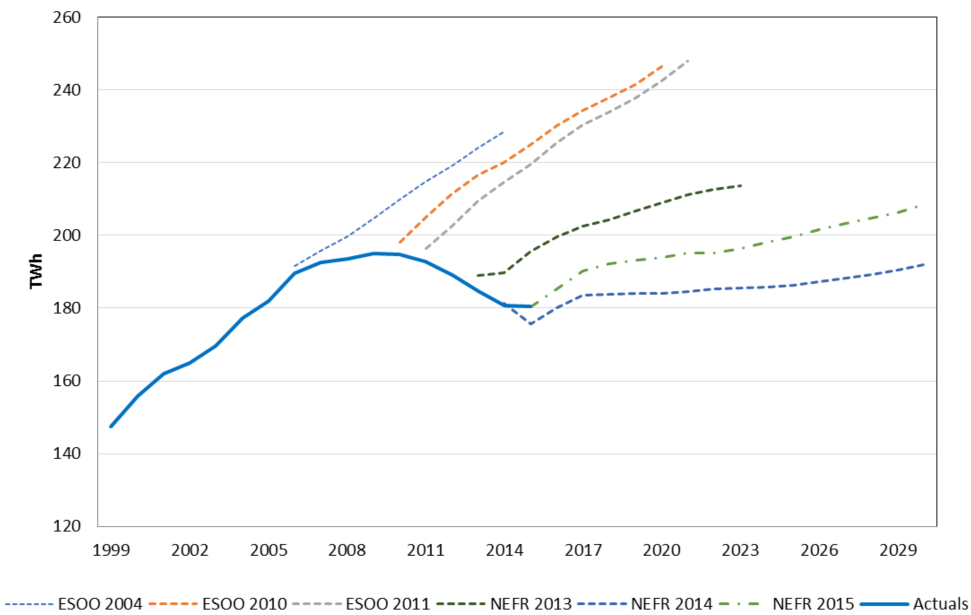
Source: Department of Industry and Science, Australian Energy Statistics, Table L.

Accurate forecasts of demand are an important feature of efficient markets and provide important information for market participants and policy makers. The objective of forecasting demand is to provide information such that there is sufficient generation capacity to meet demand for electricity.

Potential new entrant generation will use demand forecasts to form their expectations of future wholesale prices, which will be a key factor in determining whether to enter the market and the timing of this entry. TNSPs will also use demand forecasts in planning their networks to meet their obligations to reliably supply their customers.

Historically, forecasts of demand have typically over estimated actual demand outcomes, as shown in Figure 5.4.

Figure 5.4 NEM demand forecasts and actual demand



Source: AEMO and AEMC analysis

5.4.2 Future developments

As previously stated, it is too early to say with any certainty that forecast accuracy is changing. However, the Commission considers that it may be more difficult to accurately predict electricity demand for a number of reasons.

Firstly, the proliferation of distributed energy resources means that grid-supplied demand may fall in the future.[51] However, predicting the scale of the decline in demand over the longer term may be difficult as AEMO, distribution networks and other parties that need to conduct demand forecasting may not have visibility on the full amount, technical capability or location of these distributed energy resources.[52]

Future demand will also depend on the take-up rates of new technologies, for example electric vehicles, which are very uncertain at this stage. Further, future demand is also dependent on energy efficiency improvements.

In general, these future developments imply that, in future, forecasting of electricity demand must be much more granular or "bottom-up". For example, improvements in energy efficiency are generally introduced at an appliance-level, which implies that AEMO, distribution networks and other interested parties will have to forecast household demand by making a number of assumptions about how efficiency of household energy use is expected to improve over time.

51 AEMO, 2016 NEFR forecasts that PV penetration in SA will mean negative minimum demand in 2027. See AEMO, National Electricity Forecasting Report 2016, p.26

52 AEMO, Visibility of distributed energy resources, January 2017.

The Commission acknowledges that AEMO is working to improve its forecasting methodology to capture the increasing complexity of the energy market.[53] The Commission is also considering the accuracy of dispatch forecasting in a rule change related to how demand side obligations, and non-scheduled generation and load bid into central dispatch.[54]

5.5 Conclusion

Two things are clear from the above discussion. First, the pace of technological change is rapid and this will impact on the future of the energy market. Second, there is uncertainty regarding what the take-up of new technologies will be, what business models will be successful in capturing the value of these technologies and the impact that all of these developments will have on demand for electricity. Given all this uncertainty the impact of technological change on generation and transmission investment is difficult to accurately predict. The market and regulatory frameworks in place should be flexible and resilient to adapt to these changes.

Whatever the technological developments, the aim should be for arrangements that are flexible and resilient to whatever the future brings. It should allow and incentivise participants to adapt to the extent necessary to respond to consumer-driven changes in the market – while ensuring a reliable, safe and secure supply of energy.[55] But, it must do so in a way that promotes competition and the long-term interests of consumers

However there are some clearly observable trends:

- Emissions-intensive, thermal generation is exiting the market and being replaced by intermittent renewable and other low-emissions generation technology. Clarity on environmental policy is needed to predict what the future generation mix will look like.
- New business models are emerging to provide a wider range of energy services to consumers. However, the proliferation of new business models is still at an early stage and will depend in part on the take-up of distributed energy resources. The implications of these business models for transmission and generation investment will depend on the costs of technologies and potential developments in distribution network regulation.
- There is a trend toward an increase in households and businesses installing distributed energy resources. Current forecasts predict that rooftop PV will be the main type of distributed generation in the market, with increased installation of storage as battery costs decline in the 2020s. The take-up of distributed energy resources could continue as forecast or the cost of large-scale generation could fall, making distributed generation less attractive.

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53 See section 1.41 of AEMO, National Electricity Forecasting Report 2016, pp14-16.

54 More information is available from the AEMC website at hhttp://www.aemc.gov.au/Rule-Changes/Non-scheduled-generation-in-central-dispatch

55 The Commission's system security work program is discussed in section 6.4.2 of this report.

- Forecasting of demand may become more complicated and require more granular data collection and modelling as the energy market becomes more disaggregated and complex. Current processes are in place to address this issue.[56]

56 AEMO is working to improve its forecasting methodology, see section 1.41 of AEMO, National Electricity Forecasting Report 2016, pp14-16. The Commission is also considering the accuracy of dispatch forecasting in a rule change related to how demand side obligations, and non-scheduled generation and load bid into central dispatch.

6 Other trends in the energy market

6.1 Introduction

This chapter discusses other trends in the energy market. Specifically, this chapter will focus on wholesale market changes, contract market changes, interconnectors, NEM rule and regulation changes and recent announcements by governments of interventions into the electricity market.

6.2 Developments in the wholesale market

In order to safeguard reliable and secure energy supply to consumers, the appropriate investment signals must be in place so that sufficient and timely investment in various generation and demand-side technologies takes place. Price signals in the wholesale and contract markets are important drivers of new investment, particularly generation investment, in the NEM.

The NEM operates as a market where generators are paid for the electricity they produce and retailers pay for the electricity their customers consume. All energy traded through the NEM must be settled through the spot market, an arrangement referred to as the "gross pool". Both generators and retailers face risk from being exposed to spot market prices which can, and do, fluctuate significantly on a 30 minute basis. This volatility reflects the complex and dynamic environment in which the market operates.[57]

To manage their exposure to the spot market, participants typically seek to enter into contracts settled by reference to the spot market price for the region in which their production or consumption occurs. Contracts allow generators and retailers to effectively convert uncertain future spot market prices into more certain wholesale prices to better match upstream or downstream obligations that are also relatively stable across time.[58]

Therefore, in order to understand how developments in the wholesale market are affecting generation investment, it is necessary to examine the following trends:

- observed trends in the wholesale spot market price - see section 6.2.1;
- observed trends in the contract market - see section 6.2.2; and
- observed trends in inter-regional trade - see section 6.2.3.

6.2.1 Movements in wholesale spot prices

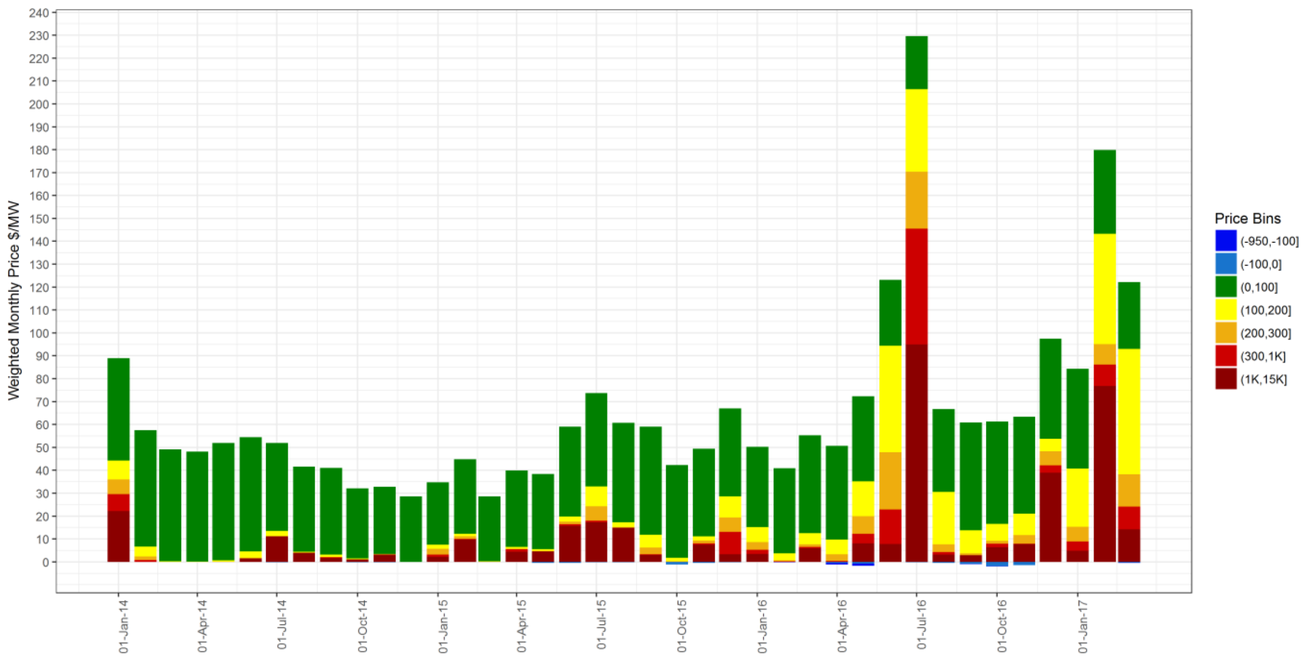
By way of illustrating the following discussion, Figure 6.1 sets out the average settlement price for South Australia from 1 January 2014 until the end of March 2017.

57 Currently, prices in the spot market range from the floor price of -$1,000 to the market price cap of $14,000.

58 Further information on risk management structures can be found in the AEMC's submission to the Independent review into the future security of the NEM. See: http://www.aemc.gov.au/getattachment/6ecd9317-10f8-40b6-b053-bfad507099b6/AEMC-submission-to-the-independent-review-on-the-f.aspx

In July 2015, the average settlement price was around $40-$50/MWh in most jurisdictions, with the outlier being South Australia with an average settlement price of $73.51/MWh, as can be seen below.[59] It can be seen that this is a relatively consistent average monthly price for the surrounding time period, albeit with a slight upward trend over the period. If we compare those prices to prices observed in recent months, it can be seen that the prices are significantly higher - the average price for South Australia in February 2017 was $179.85/MWh. It can also be seen that there is a significant higher proportion of individual dispatch intervals that settle at prices above $300/MWh, in turn, driving the higher average prices.

Figure 6.1 South Australia time weighted dispatch price

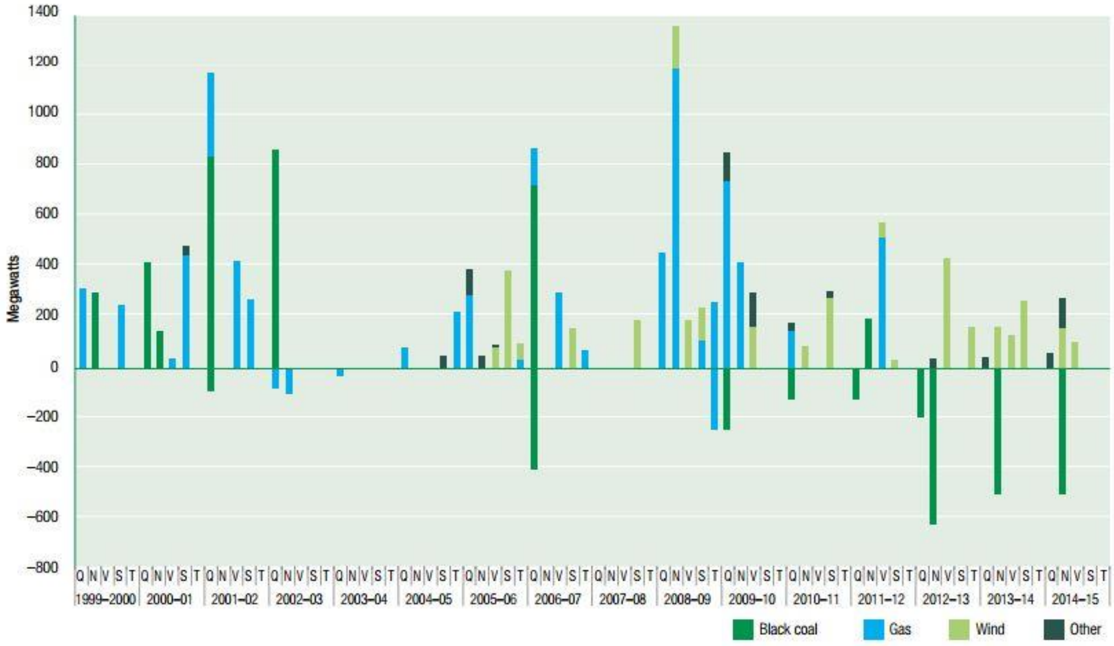


Source: AEMO data; AEMC analysis.

In order to explain some of these trends in observed wholesale market prices, we need to unpack the drivers of these trends. Figure 6.2 shows trends in annual investment and retirement in registered generation capacity in the NEM. This is due to the LRET environmental policy encouraging more new-entrant intermittent generation into them market, particularly wind, at the same time as coal-fired generators are withdrawing. In the past, intermittent generation sources (such as wind and solar) accounted for only a small fraction of total electricity supply. Now, however, they are a key part of the South Australian power system and their contribution is continuing to grow. This is discussed in further detail in chapters 4 and 5.

59 In comparison, the average price for July 2015 for NSW was $39.15; for $46.66 for Queensland; $34.90 for Tasmania; and $34.75 for Victoria.

Figure 6.2 Registered generation capacity - annual investment and retirements



AER, State of the Energy Market 2015, p. 36.

The changing generation mix means that wholesale electricity market outcomes are now increasingly connected with:

- **environmental policy** - the LRET has resulted in substantial investment in renewable (wind and solar) generation - see Box 6.1. Uncertainty regarding government environmental policies also impacts on the generation sector;
- the **wholesale gas market** - the price for gas affects the electricity price through gas-fired power stations, which are expected to increasingly be the price-setting generator. Further, gas generators are one source for the provision of hedge contracts within the electricity market. A well-functioning contract market is a fundamental part of being able to manage price risk and is a prerequisite for competitive industry structure and delivering reliable supply of electricity over time; and
- **system security** - the increased reliance on renewable non-synchronous generation affects the technical characteristics of the system and the ability to supply reliable, secure energy.

A notable example of this was the July 2016 wholesale price outcomes in South Australia - see the chart above - which highlight the level of connectedness in the market. In South Australia, there has been significant investment in renewable intermittent generation driven by the LRET. Limited generation from intermittent sources in July, combined with the withdrawal of a coal-fired generator, a constrained interconnector, higher gas prices, and cold weather conditions, were drivers of a period of volatile and high prices.

Another driver of wholesale outcomes is the retirement of two large generators - Northern and Hazelwood. The closure of these power stations is discussed in more detail in section 5.2.

It is also worth noting that in recent months there has been more discussion around keeping power stations *open* for system security and reliable benefits, rather than closing. This is discussed more in section 6.6.

Box 6.1 Implications of RET policy design on the electricity market

The principal policy to reduce emissions in the electricity sector is the Renewable Energy Target (RET).[60] The RET is a policy designed to encourage investment in renewable energy generation. It comprises the large-scale renewable energy target (LRET) and the small-scale renewable energy scheme (SRES). The LRET is the largest component of the RET policy and directly impacts the NEM.

The LRET provides an incentive for investment in renewable energy technology by requiring liable entities (mostly retailers) to source a proportion of their electricity from renewable sources. Eligible generators create large-scale generation certificates (LGCs) that retailers are required to acquire and surrender. It is the availability of LGC revenue (which can be earned in addition to revenue earned through the wholesale price) that encourages renewable generation to enter the market.

A key problem with the existing LRET is the impact of its design on risk allocation and incentives faced by existing generators, consumers and new entrant renewable generators.

Under the LRET, the wholesale market price is no longer the primary signal for new investment in renewable energy generation. Instead, the price signal is provided by the LGC price and the target amount (or percentage). In effect, renewable generation is compensated through payments from retailers and other large users, in addition to the wholesale market revenue.

These other price signals have meant that renewable energy generators have continued to enter the market, particularly in South Australia, despite lower wholesale market prices. The resulting exit of existing generators has resulted in two significant and, importantly, unintended impacts on wholesale market prices in both the energy and ancillary services markets:

1. An increase in both the level and volatility of wholesale energy prices. This is due to a combination of lower supply, increased reliance on more expensive gas generation (particularly in South Australia), and a greater share of intermittent generation in the generation mix. Higher and more volatile market prices have increased the price of forward contracts, and have also offset the short-term merit-order effect.
2. A lack of liquidity in the forward contract market, which has exacerbated the rise in forward prices. Retailers and generators are typically incentivised to enter into long-term contracts to minimise price risk. However, generators that also receive LGC revenue may have less incentive than other generators to enter into contracts, as the LGC revenues mitigate these

60 See chapter 4 for a discussion of the effect that environment and emissions reduction policies have on investment in generation.

generators' exposure to wholesale energy prices and they may find it hard to provide 'firm' contracts given the intermittent nature of their generation. Furthermore, as traditional generators retire, and more capacity comes from renewables, fewer generators are available to offer contracts, further raising the cost of forward contracts.

The exit of synchronous generators in South Australia has reduced competition amongst suppliers of frequency control and ancillary services (FCAS), raising the market price of FCAS. The exit of synchronous generators has also reduced the system's inertia, making it more susceptible to large changes in frequency from unexpected changes in electricity demand or supply. These impacts on risk management and risk allocation are unintended consequences of the existing subsidy mechanism used to achieve the government's RET policy.

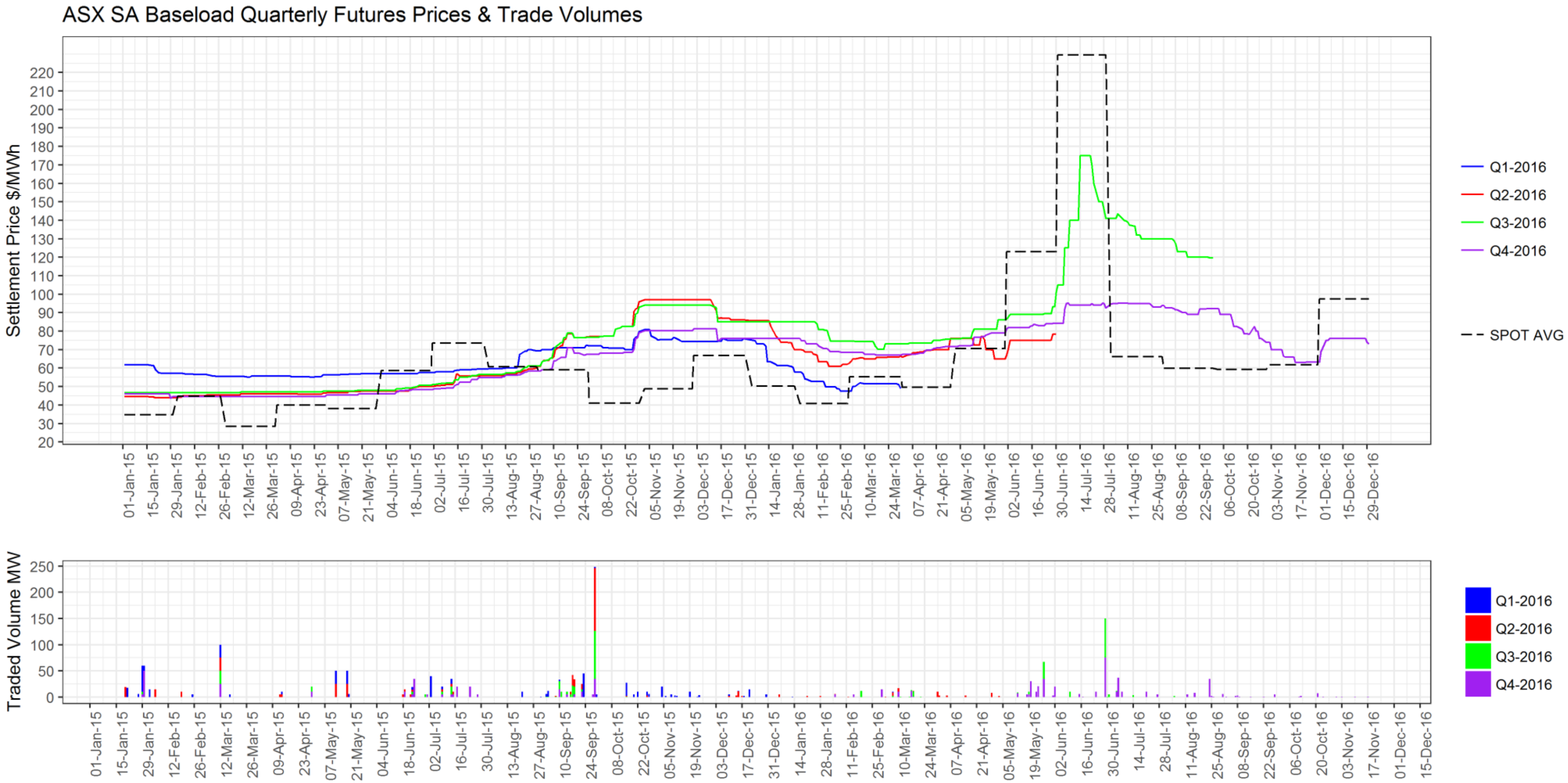
6.2.2 Movements in contract prices

While the contract market is distinct from the spot market, the prices of contracts are based on forecast spot market outcomes. This means that the expectation of high prices in the spot market should result in higher contract prices, which in turn allow potential investors to sell contracts and underwrite new investment in generation. Conversely, the expectation of low prices in the spot market will result in lower contract prices, which in turn reduces the ability of potential investors to sell contracts to underwrite new investment.

Figure 6.3 shows the strike price of ASX traded baseload swap contracts[61] for South Australia, differentiated by when the contract product will conclude, that is, the quarters in 2016 in which the contract will end. It is to be expected that as the contract reaches the end of its life, the price for the contracts should approximate observed wholesale spot prices (represented by the dashed line in the below chart). It can also been seen that as the observed wholesale spot prices in the South Australian market increased, this in turn resulted in higher contract prices.

61 A swap contract trades a fixed volume of energy during a fixed period for a fixed price (the strike price). The wholesale market spot price is, in effect, swapped for a fixed contract price (the strike price). The contract is settled through payment between counterparties based on the difference between the spot price and the fixed price.

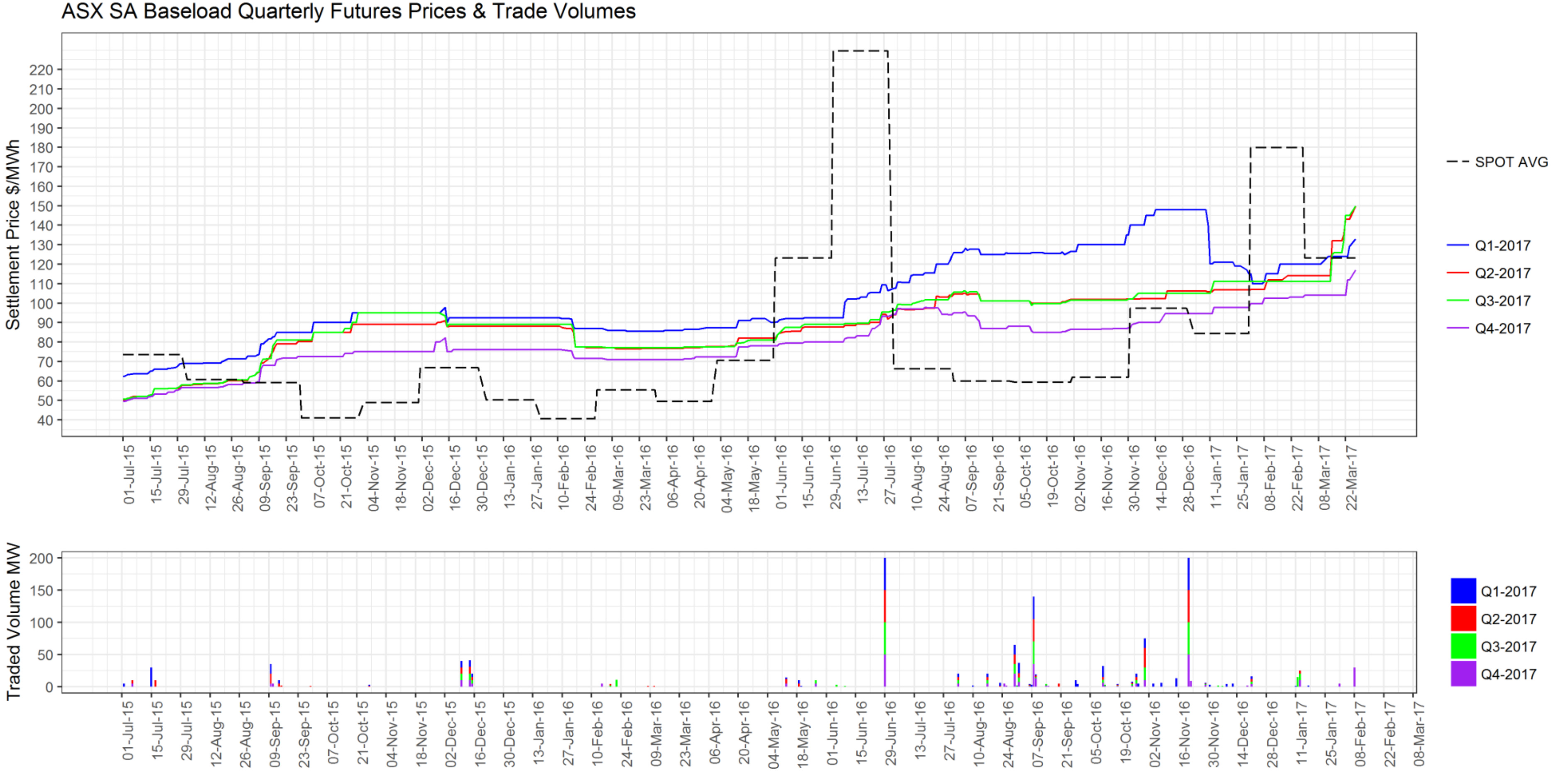
Figure 6.3 ASX SA Baseload Quarterly Futures Prices and Trade Volumes - 2016



Source: AEMO data; ASXEnergy; AEMC analysis.

Figure 6.4 shows the same graph as above, but represents trading for contracts that end in 2017. The upward trend for forward prices in the South Australian market has continued through to contracts in 2017.

Figure 6.4 ASX SA Baseload Quarterly Futures Prices and Trade Volumes - 2017



Source: AEMO data; ASXEnergy; AEMC analysis.

As noted above, contract prices provide information about expected future spot prices, which in turn reflect participants' views of future wholesale market and supply conditions. A liquid contract market is critical in supporting new entry and expansion in the upstream and downstream segments of the market. For example, long-term hedge contracts may be a material prerequisite for a potential new entrant generator to arrange for financing of the upfront costs of project development. The costs of financing may be substantially increased for a new entrant if they cannot obtain such a hedge contract or be confident of being able to access a relatively liquid contract market in the future.

Similar considerations apply to actual and prospective retailers. A potential new entrant retailer (or an existing retailer looking to expand its retail portfolio) will need to be able to obtain hedging contracts to manage its exposure to risk in the spot market or have a balance sheet that enables it to build its own generation plant to internally hedge this risk. A lack of liquidity in the contract market may create a barrier to entry and expansion in the retail market, reducing competitive pressures on existing retailers to charge prices that reflect efficient costs and improve their offers. Further, it could result in greater vertical integration due to energy market risks that are too costly or unmanageable to hedge against.

6.2.3 Movements in inter-regional trade

The NEM is an interconnected system. Power flows between regions from low-priced to high-priced regions. Trading and contracting between regions is generally more complicated than within regions. Inter-regional trade generally refers to:

- a generator in one region selling forward contracts to a retailer in another region of the NEM (or, conversely, a retailer hedging its retail risk in one region through purchased contracts with a generator located in another region); or
- a vertically integrated participant that is attempting to serve its retail customers in one region with generation assets that are located in another region.

Therefore, electricity is sold across regions through interconnectors which connect two adjacent regions. They deliver energy from lower price regions to higher price regions and so equalise prices between regions. In a planning sense there is no such physical asset as an "interconnector" - but typically involve transmission lines that cross regional boundaries and that involve more than one network planner. Interconnectors operate as a partial substitute for local generation within a region by allowing consumer demand in one region to be served by electricity supply from generators in an interconnected region.

However, contracting across regions is more difficult compared to contracting within regions - see Box 6.2.

Box 6.2 Limitations on contracting across interconnectors

Hedge Contracts

All hedge contracts (whether exchange-traded or over the counter (OTC), swaps or caps) need to nominate a regional reference price (RRP) against which they are settled. Generators and retailers in a given region typically seek to enter into contracts settled against their local RRP, as this ensures an alignment between the price at which the participant's physical electricity generation or consumption is settled and the price at which their contracts are settled. This enables the relevant contract to provide a financially firm hedge for the participant's spot market exposure.

A participant can also enter into contracts settled against a different region's RRP. However, the drawback with entering into a contract settled against a different region's RRP to the RRP at which a participant is settled is that it exposes the participant to 'basis risk' – which is the risk that the RRP at which the contract is settled diverges from the RRP at which the participant's output or consumption is settled. Basis risk means that the contract may not provide a firm hedge for the participant's spot market exposure. Basis risk arises due to the fact that interconnectors can be constrained, leading to a divergence in RRPs between interconnected regions.

As a result, generators do not normally sell cap contracts settled at a different region's RRP, as caps tend to impose payments obligations on sellers precisely at those times when interconnectors are most likely to be constrained. Generators can be somewhat more willing to enter swap contracts settled at a different region's RRP, particularly during periods of quiescent prices. Retailers may also be willing to hedge their exposures through a mix of inter-regional swaps and local region caps. However, hedging in this way still exposes participants to particular risks that arise out of contracting across an interconnector.

Settlement residue units

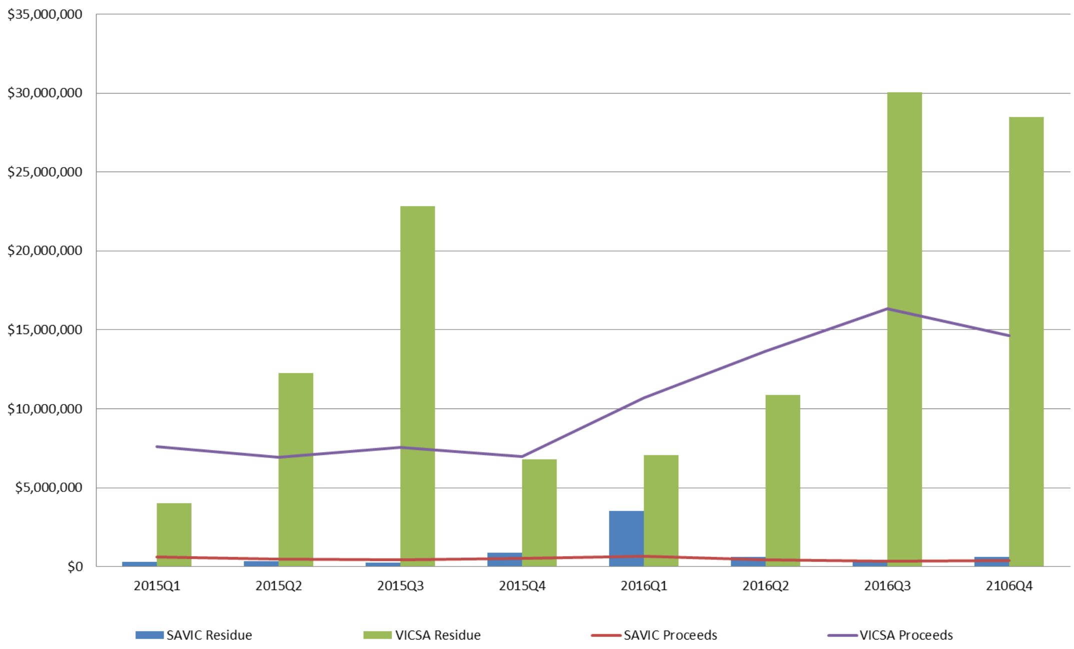
Participants can partially hedge exposures via contracts settled against a different region's RRP, using inter-regional settlement residue units (IRSR units) that accrue when prices between regions separate. I

RSR units, provide the holder with a right to a share of the inter-regional settlement residue surplus that arises when interconnectors enable electricity from a region with a lower RRP to be transported and sold into a region with a higher RRP. The value of the IRSR is equal to the difference between the price paid by retailers in an importing region and the price received by generators in an exporting region, multiplied by the amount of flow across the relevant interconnector. These rights to a share of the inter-regional settlement residue surplus are known as settlements residue auction (SRA) units, after the auction that AEMO holds every quarter. However, IRSR units do not provide a perfect hedge for inter-regional price separation because RRPs may diverge even when flows across an interconnector are below their expected limit.

> **Interconnectors**
>
> If there is effective competition and liquid hedge markets in two regions, interconnectors can lower total system costs through "gains from trade" where a greater share of demand is satisfied by lower cost generation at the expense of higher cost generation.
>
> Although interconnectors can bring energy into a region, they cannot bring a corresponding supply of hedge contracts, and therefore cannot fully replace a competitive industry structure within each region itself.

Figure 6.5 shows the trends in the SRA unit for the two products (unit categories) available between South Australia and Victoria. What can be seen is that the proceeds from the auctions for these products are increasing from 2015 to 2016, as well as the residues that are earned from the auction (which can be considered to represent the price differences between the two regions).

Figure 6.5 SRA proceeds and residues accumulated for the South Australia - Victorian interconnectors



Source: AEMO data, AEMC analysis

As the Commission has previously noted, the effectiveness of inter-regional hedging could be improved. This is because the payout of the SRA unit is highly dependent on flow, and the current market arrangements mean that flows on the interconnector are reduced frequency.[62]

62 See, AEMC, Optional Firm Access, Design and Testing, July 2015, p. 92.

6.3 Interconnectors

As discussed above, interconnectors act as a *partial* substitute for local generation within a region. Therefore, it is important to understand trends in interconnector investment, in order to understand drivers of transmission and generation investment.

In July 2015, the upgrade of the Heywood interconnector (between South Australia and Victoria) was underway. This followed ElectraNet and AEMO completing a RIT-T, determining in 2013, that such an upgrade would create net market benefits.

More recently, there has been additional consideration, and studies into interconnectors, including:

- in early 2016, the Commonwealth and Tasmanian Governments requested a feasibility study of whether a second electricity interconnector between Tasmania and the mainland would help to address long-term energy security issues and facilitate investment in renewable energy;[63]
- in August 2016, TransGrid published analysis undertaken by PwC evaluating analysis of an interconnector between NSW and South Australia;[64]
- in September 2016, the Australian Energy Council published a report by Acil Allen Consulting looking at the South Australian technical challenges, which included consideration of increased interconnector between South Australia and the eastern states;[65]
- in December 2016, AEMO, through its National Transmission Network Development Plan noted that high-level modelling showed the potential benefits of further interconnection;[66]
- ElectraNet is considering, through a RIT-T which commenced in late 2016, potential new interconnection between South Australia and the eastern states;
- in March 2017, TransGrid announced they had commissioned reports by Deloitte and FIT Consulting showing that a new interconnector between South Australia and NSW would boost competition and provide significant economic benefits, including reducing power costs.[67]

Therefore, there is significantly more focus on interconnectors today, compared with July 2015. It is important to note that while there has been an increased focus on interconnectors, they are not a perfect substitute for transmission or generation infrastructure in a region because market participants cannot contract with an interconnector. No decisions have been made to build any new interconnectors.

63 See: http://www.environment.gov.au/energy/tasmanian-energy-taskforce

64 See https://www.transgrid.com.au/news-views/news/2016/Documents/TransGrid%20SA-NSW%20Interconnector%20Report%20(Final).pdf

65 http://www.acilallen.com.au/cms_files/ACILAllenRenewablesSA_2016.pdf

66 AEMO, National Transmission Network Development Plan, December 2016, p. 3.

67 M Ludlow, 'Interconnector would solve SA power woes, says TransGrid, *Australian Financial Review*, 6 March 2017.

6.4 NEM rule and regulation changes

The AEMC is currently considering a number of rule changes that will potentially impact on generation and transmission investment in the NEM. These are discussed in more detail below.

6.4.1 Five minute settlement

The AEMC is currently assessing the five minute settlement rule change request, which was submitted by Sun Metals Corporation. The proposal seeks to align the dispatch and settlement intervals in the wholesale electricity market in order to improve market efficiency. This rule change request has attracted a high level of interest from a diverse mix of stakeholders. The proposed rule change would have implications for the spot market, the contract market, IT systems (including those of generators, retailers and the market operator) and metering, among others. Given this, the proposed rule change, if adopted, would impact heavily on generation investment decisions (including how financing is obtained).

On 11 April 2017, the Commission published a Directions Paper on this rule change request. This expressed the Commission’s initial position that given the transition underway in the NEM, the adoption of five minute settlement after a suitable transition period would have a material benefit that is likely to outweigh the cost. This initial view is subject to stakeholder feedback on detailed costs and benefits. Stakeholder feedback on this initial position will inform the Commission’s draft decision on the rule change request.

6.4.2 System security work program

The AEMC is currently conducting a system security work program, which comprises the: system security markets frameworks review and the emergency frequency control scheme rule change.

System security market frameworks review

New generation technologies have technical characteristics that differ from the plant they are replacing. The impact of non-synchronous generation, such as wind power and solar PV, on how the system is maintained in a secure state will be an important focus in the coming years.

The AEMC is undertaking the system security market frameworks review to consider, develop and implement changes to the market rules to allow the continued uptake of these new forms of generation, while maintaining the security of the system. The review is drawing upon work being undertaken by AEMO, as part of its Future Power System Security Program, to identify and prioritise current and future challenges to maintaining system security.

The AEMC self-initiated the review in July 2016 to address two key issues highlighted by AEMO: the management of frequency and of system strength in a power system with reduced levels of synchronous generation. The review is also being conducted in parallel with the assessment of a number of rule change requests submitted by AGL and the South Australian Government relating to frequency control and system strength.

On 23 March 2017, the AEMC published a directions paper to present its proposed approach to resolving these issues. It builds on the interim report, published in December 2016, which explored the challenges associated with frequency control and set out potential mechanisms for procuring new frequency management services. The directions paper also provides a detailed discussion of system strength and presents a proposed approach.

As set out in the directions paper, the Commission's preliminary view is that frequency control in the NEM would be enhanced by the introduction of both:

- a mechanism to obtain inertia, which would reduce the rate of change of frequency (RoCoF) following a contingency event and extend the time available to restore the frequency; and
- a fast frequency response service, which would act to arrest the frequency change more quickly than the current fastest acting contingency frequency control ancillary services, which has a response time of up to six seconds.

To implement these services, the Commission proposed two packages of complementary measures relating to inertia and fast frequency response. A staged approach to implementation of these changes seeks to strike a balance between addressing immediate issues related to the management of power system security and developing an efficient and effective framework to address such issues in the medium to longer term.

The immediate package contains a number of complementary measures to maintain control of power system frequency following a contingency event, including:

- a requirement on TNSPs to provide and maintain a defined operating level of inertia at all times;
- the ability for TNSPs, as an interim measure, to contract with third party providers of fast frequency response services where the TNSP considers, and AEMO agrees, that a fast frequency response service can be used to meet the required operating inertia level; and
- an obligation on new non-synchronous generators to have the capability to provide fast frequency response services.

The Commission is also proposing that two additional mechanisms should be subsequently implemented to enhance this immediate package: a TNSP incentive framework to guide investments in inertia; and a market sourcing approach for fast frequency response. These mechanisms would aim to improve the overall effectiveness and efficiency with which inertia and fast frequency response services are procured in the long term.

The directions paper also sets out the Commission's proposed approach to system strength, which is to amend the rules to clarify that NSPs should be responsible for maintaining an agreed minimum short circuit ratio to connected generators. Generators would continue to be required to meet their registered performance standards above this agreed level.

Submissions to this directions paper are due on 20 April 2017.

Emergency frequency control schemes rule change request

Emergency frequency control schemes protect the power system following a major disturbance, such as the failure of a large generator. These schemes shed load or generation in a controlled and coordinated manner in order to prevent major blackouts. They are essential to maintaining a secure and reliable supply of electricity for consumers.

The AEMC recently considered two rule changes that were designed to enhance the frameworks for emergency frequency control schemes in the NEM. The final determination for these consolidated rule change requests was made on 30 March 2017. The final rule includes:

- a framework to regularly review current and emerging power system frequency risks, and then identify and implement the most efficient means of managing emergency frequency events;
- an enhanced emergency frequency control scheme framework to allow for the efficient use of all available technological solutions to limit the consequences of emergency frequency events, including a formalised arrangement for the management of over-frequency events; and
- a new classification of contingency event, the protected event, that will allow AEMO to manage the system at all times by using some ex-ante solutions, as well as load shedding, to limit the consequences of the protected event.

This integrated and enhanced framework for emergency frequency control schemes and protected events will support security of supply for consumers as the generation mix changes and technology evolves. However, it is important these measures are delivered efficiently, so that costs for consumers are as low as possible. The final rule therefore sets out clear governance arrangements, including the requirement for robust cost benefit processes.

Conclusions

The widespread deployment of new, non-synchronous generating technologies, such as wind farms and solar panels, is having major impacts on the operation of the power system. The work that is being conducted through the above projects will consider, develop and implement changes to the market rules to allow the continued uptake of these new forms of generation while maintaining the security of the system. The outcomes of these pieces of work are likely to impact on both generation and transmission investment, in particular:

- system strength involves localised considerations, and so any enhancements to the frameworks that change the market rules in respect of system strength will likely result in changes to how transmission and generation investment is planned and carried out;
- the introduction of a fast frequency response market will provide an additional source of revenue to new generation, potentially resulting in different generation technologies entering the market; and

- the introduction of a clear and transparent framework around the development of emergency frequency control schemes will enable new technologies and solutions to provide more effective emergency frequency control schemes to be identified and considered, improving security of supply for consumers again impacting on the nature of transmission and generation investment required.

6.4.3 Transmission connections and planning arrangements

The AEMC is currently considering the transmission connections and planning arrangements rule change request, which was submitted by the COAG Energy Council. The rule change request seeks to improve transparency, contestability and clarity in the transmission connections framework, while maintaining clear accountability for outcomes on the shared transmission network that affect consumers. It also seeks to enhance the efficiency of existing transmission planning arrangements and promote a more coordinated approach to transmission planning.

The draft determination was published on 24 November 2016, with a final determination due on 23 May 2017.

The draft rule provided more choice, control and certainty for connecting parties, while at the same time making it clear that the incumbent TNSPs are accountable for a reliable, safe and secure network. Specifically, the draft rule:

- better defines the assets and services required to facilitate a connection to the transmission network;
- improves the clarity of the transmission connection process;
- introduces competition for the provision of some of the services required to facilitate a connection to the transmission network;
- makes it clear that incumbent TNSPs have responsibility for the control and operation of the shared transmission network, which promotes a reliable, safe and secure network for consumers;
- requires TNSPs to publish more information about how to connect to their network, and provide certain information to connecting parties on request;
- strengthens the principles that underpin negotiations between connecting parties and incumbent TNSPs;
- introduces a formal ability for either party to engage an independent engineer to provide advice on the technical aspects of a connection;
- clarifies the process that applies to disputes about transmission connections;
- requires TNSPs' annual planning reports to include information about network constraints, load forecasting methodologies and changes since the last report;
- requires the AER to develop a guideline to support consistency across annual planning reports; and
- requires TNSPs to undertake joint planning on investments in other transmission networks to deliver market and reliability benefits in their own network.

If a final rule is made in a similar form to the draft rule, these changes will create certainty about the connections framework in the NEM - making it clear what arrangements occur, and what process is followed when parties connect to the transmission network.

6.4.4 Replacement expenditure planning arrangements

The AEMC is currently considering a rule change request that seeks to increase the transparency of network asset replacement decisions by electricity TNSPs and DNSPs.

A draft determination for this rule change request is published on 11 April 2017, with submissions due on 6 June 2017.

The draft rule makes a number of amendments to the planning and investment framework with the aim of creating a set of requirements that will apply equally to all potential network capital investments regardless of the reason for the investment. The draft rule:

- specifies that information on all planned retirements in distribution and transmission networks is to be included in the distribution and transmission annual planning reports including the reasons for the retirements;
- specifies that information on planned de-ratings that result in a constraint on a network is to be included in the annual planning reports including the reasons for the de-ratings;
- aligns reporting requirements on network needs and options to address these in a replacement context with those required in an augmentation context for transmission networks;
- extends the distribution and transmission regulatory investment tests to network replacement expenditure decisions;
- requires reporting on the approach to asset management to be included in the transmission annual planning reports;
- clarifies that the regulatory investment test for transmission is to be undertaken again where there is a material change in circumstances (however, a network service provider can seek an exemption to undertake the test again from the Australian Energy Regulator); and
- specifies that distribution annual planning reports will need to include information on investments in information technology and communications systems related to the management of network assets.

If a final rule is made in a similar form to the draft rule, this will impact on how transmission replacement decisions are made, in particular, improving the coordination of transmission and generation investment. This is because it would improve the information being exchanged between the generation and transmission sectors, through applying public consultation requirements relating to replacement expenditure. Generators would be able to provide information to the TNSP through making submissions to the RIT-T process, where replacements would be valuable to them, or not, in a more transparent way than currently occurs.

6.4.5 Reliability standards and settings review

The reliability standard[68] and settings[69] in the NEM are important mechanisms to encourage sufficient investment in generation capacity to meet consumer demand for energy while protecting market participants from substantial risks that threaten the overall stability and integrity of the market.

The Reliability Panel is currently undertaking a review of the reliability standards and settings.[70] The review must be completed by 30 April 2018, and will involve the Panel considering whether the standards and settings remain suitable for current market arrangements.

The Panel may submit a rule change request to the AEMC if it decides to recommend changes to the reliability standard and/or settings.

Collectively, the reliability settings:

- establish the price envelope within which energy supply and demand is balanced in the wholesale market;
- allow the market to send price signals to market participants, and create incentives to enter into hedging contracts, to support investment in sufficient generation capacity or demand side response to meet the reliability standard; and
- limit financial risk for market participants.

Accordingly, any changes (or otherwise) to the reliability settings will impact on generation investment decisions.

6.5 Independent review into the future security of the National Electricity Market

On 7 October 2016, COAG Energy Ministers agreed to an independent review of the NEM, led by the Chief Scientist, Dr. Alan Finkel, to take stock of its current security and reliability and to provide advice to governments on a coordinated, national reform blueprint. The national reform blueprint will outline national policy, legislative, governance and rule changes required to maintain the security, reliability, affordability and sustainability of the NEM. A preliminary report was published in December 2016.

The AEMC wrote a submission to the preliminary report, which outlined matters which the Commission believes are critical for the security and reliability of the NEM:

- **Good governance** - the governance framework consciously allocates decision making responsibilities to a range of parties and gives those parties the tools and

68 The reliability standard is an ex-ante planning standard. It feeds into various NEM wholesale pricing parameters that form part of the framework in which investment decisions to meet consumer demand for electricity are made. The current standard, expressed in terms of the maximum unserved energy (USE), is set at a maximum USE of 0.002 per cent of the total energy demanded in each region per financial year.

69 The reliability settings comprise four price mechanisms: the market price cap; the cumulative price threshold; the market floor price; and the administered price cap.

70 See: http://www.aemc.gov.au/Markets-Reviews-Advice/Reliability-Standard-and-Settings-Review-2018

mechanisms to implement them. While the governance structure is generally sound, there are a number of opportunities to improve the effective functioning of the current arrangements to support timely, well informed decisions and inclusive processes. Pursuing these opportunities is crucial if the gap between issues emerging and being addressed is to be shortened.

- **Effective integration of emissions reduction and energy policy** - While it is clearly the role of governments to determine an emissions reduction policy objective for the electricity sector, the design of the mechanism is critical in both achieving the emissions objective and maintaining and enhancing an efficient, safe, secure and reliable energy system that delivers the best outcomes for consumers.
- **Giving investors and consumers confidence** - Appropriate investment signals, risk allocation and risk management tools are critical in achieving sufficient and timely investment in the technologies necessary to maintain reliability, security of supply and competition in the retail market as the sector transforms.

The final report for this review is due to be submitted to the COAG by the middle of 2017. It is worth noting that over 360 submissions were received to the preliminary paper - with many commenting on matters relevant to this review, that is, the drivers of transmission and generation investment - see Box 6.3.

Box 6.3 Submissions to the Independent review into the future security of the NEM

It is worth noting that a number of submissions to the Independent review into the future security of the NEM commented on both the drivers of transmission and generation investment, but more specifically, the coordination that occurs between generation and transmission. Some of the more notable comments are summarised below.

> "As previously identified by the AEMC, the existing transmission pricing arrangements do not place a strong signal on where new generators should locate. Without changes to the transmission pricing arrangements, new generation investment decisions will not take into account the locational effect on networks. Customers could end up paying higher network charges because of poor price signals. Transmission pricing has been one of the more intractable issues since market commencement. However, without changes to network pricing arrangements, we face the real prospect that there will be significant amounts of underutilised network capacity (with the retirement of existing generation) at a time when there will also be needs to expand the network (to connect new remotely located generation). If we are to deliver emissions reduction at least cost to the consumers, it would appear to be important to send stronger signals around the location of new generation. We would encourage the Review Panel to consider whether a changed generation sector means that there is a need to review these locational pricing issues"

AER submission to the Independent review into the future security of the NEM, p. 9.

"The location of new generation, including wind and solar farms, is currently being determined based on the shape of the existing network. Locations with spare transmission capacity have the lowest connection costs, as new connections face the incremental costs they cause. However, there is a question whether a more efficient outcome would look to locate generation where it is technically most efficient (akin to building a coal power station next to the coal deposit) and the building the network to support that. (i.e. building the network that will optimise new renewable generation.)"

AusNet Services, submission to the Independent review into the future security of the NEM, technical attachment, p. 13.

"Another potential barrier to investment is the absence of deep access rights for generators. Generators therefore face subsequent connection risk – i.e. the risk that a new connecting generator will cause congestion on the transmission network that diminishes existing generators' ability to access the regional reference price. For example, AEMO has highlighted this issue in relation to its Transmission planner role in Victoria and the connection of new renewable energy generators in North Western Victoria19. Access reform is contentious because it brings the interests of different generators into conflict."

AEMO, submission to the Independent review into the future security of the NEM, p. 14.

"[T]he incentives or subsidies for renewables and the planning and approvals of these assets must consider and account for their impact on the transmission network and Market. There is a growing number of cases where subsidised renewables are being built in constrained parts of the electricity network which is, perversely, leading to outcomes counter to the intention of the subsidy and project i.e. no net new generation and pushing out low emission gas for coal-fired generation."

ERM Power, submission to the Independent review into the future security of the NEM, p. 4.

"While the open access arrangements on the transmission and distribution systems have enabled much new investment in the power system, there is the possibility of large generation projects in limited grid areas affecting all connected parties and undermining the business case of existing generators. It may be time for the Rules to set some limits to the impact that new projects can have on transmission constraints (and neighbouring generation). At this point in time there is no limit, although originally the Rules did place an obligation on network service providers to consider the impact on other generators."

Pacific Hydro, submission to the Independent review into the future security of the NEM, p. 10.

6.6 Government interventions

In the last month, there have been a number of announcements by governments relating to the energy sector, including:

- the Victorian Government's announcement calling for expressions of interest to build Australia's first grid scale battery storage facility;[71]
- South Australia's "our energy plan", which amongst other things, includes building a state-owned gas power generator, funding a large battery project, incentives for gas development, and new ministerial powers to direct the market;[72]
- a feasibility study by the Australian Renewable Energy Agency into the Prime Minister's announcement to boost the output of the Snowy Mountains Hydroelectric scheme by 2000 megawatts;[73] and
- the development of an implementation plan with market bodies and industry participants to deliver on gas companies 'guarantee that gas is available to meet demand', fast tracking any possible market reforms, and transparency measures.[74]

These government announcements are counter to any move towards more market driven transmission and generation investment. It is worth noting that a number of these announcements involve the (potential) construction of new generation in the NEM. . If generation investment decisions are made by governments it is harder to optimise the total system costs of such decisions, in large part because the allocation of risk between consumers and businesses are unlikely to align. This potentially undermines the coordination between the generation and transmission sectors.

6.7 Conclusion

In relation to trends in wholesale markets, NEM rules and regulations, and other developments, these drivers have changed substantially since July 2015. Specifically:

- the accelerating change occurring in the deeply connected energy sector is: linking electricity and gas; spreading technological innovation across new energy services for consumers; and including other policy areas like the environment, so affecting outcomes in the wholesale market, contract market, and in turn generation investment;
- there are a number of rule change requests that the AEMC is currently considering where the outcomes, if final rules are made, will influence how generation and transmission investment decisions are made in the NEM; and

71 See: http://www.premier.vic.gov.au/australias-largest-battery-to-be-built-in-victoria/

72 See: http://ourenergyplan.sa.gov.au/

73 See: https://www.pm.gov.au/media/2017-03-16/securing-australias-energy-future-snowy-mountains-20

74 See: https://www.pm.gov.au/media/2017-03-15/measures-agreed-cheaper-more-reliable-gas

- the independent review into the future security of the NEM is considering similar issues, with several submissions to that review commenting on the coordination of generation and transmission investment in the NEM; and
- recent announcements of government interventions into the energy market are potentially resulting in *less* coordination of generation and transmission investment than has historically occurred.

A Assessment of Regulatory Investment Tests for Transmission

The below table analyses the history of RIT-Ts since the test came into effect in August 2010. This analysis underpins the discussion in chapter 3. Where there is <u>underlining</u> it illustrates where TNSPs have published additional information beyond what is specified in the RIT-T process set out in the Rules. Where items are **bolded** it represents the fact that the RIT-T process has concluded, in the absence of bolding, the process is either still under consideration, or was concluded early.

Table A.1 Summary of RIT-Ts undertaken to date

Year / TNSP	ElectraNet	AEMO	TasNetworks	TransGrid	Powerlink
2017		Western Thermal Capacity: AEMO is currently conducting a RIT-T on this project. At this stage, AEMO has just released a request for information on this project, rather than any of the formal documents required for the completion of the RIT-T.[75]			
2016	South Australian Energy Transformation RIT-T Project Specification Consultation Report published in November 2016. In addition a Market Modelling Approach and Assumptions report was published for consultation in late December 2016, as well as a supplementary			Powering Sydney's Future: In October 2016, TransGrid commenced a RIT-T on this project. This is being undertaken in conjunction with Ausgrid. In December 2016, TransGrid published a paper setting out more detail on non-network options for	

75 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Regulatory-investment-tests-for-transmission

Year / TNSP	ElectraNet	AEMO	TasNetworks	TransGrid	Powerlink
	information paper on 13 February 2017.[76] Northern South Australia Region Voltage Control RIT-T Project Specification Consultation Report published in August 2016. Since that time ElectraNet has been engaging with customers to better understand the dynamic behaviour of customer demands in the area. Based on this, ElectraNet received new information and has now completed a re-evaluation of the identified need based on the new information. Accordingly, ElectraNet announced the cancellation of the RIT-T as the continuation of the process is no longer required.[77]			this project.[78]	
2015					
2014	Baroota Substation Upgrade: A RIT-T was commenced on this project in 2014, but was never concluded since the project was			**QNI Interconnector: In 2014, the RIT-T on this project concluded. This waws undertaken in**	

76 See: https://www.electranet.com.au/projects/south-australian-energy-transformation/

77 See: https://www.electranet.com.au/projects/northern-south-australia-region-voltage-control/

78 See: https://www.transgrid.com.au/powering-sydney

Year / TNSP	ElectraNet	AEMO	TasNetworks	TransGrid	Powerlink
	initially proposed to meet an increased reliability standard set out in the South Australian Electricity Transmission Code, which has since been removed.			**conjunction with TransGrid and Powerlink. It was concluded that nothing would be done in relation to an upgrade of QNI.**[79]	
2013	**Dalrymple Substation Upgrade: In 2013, a RIT-T on this project was completed. Construction works associated with this project are currently underway.**		**Regional Victorian Thermal Capacity Support: In 2013, a RIT-T concluded on this project. It resulted in AEMO deciding that investments were necessary in this regard.**		**Supply to Bowen Basin coal mining area: In 2013, a RIT-T concluded on this project. Powelrink concluded that the preferred option was to undertake network investment.**
2012	Managing voltages in the mid North: RIT-T Project Specification Consultation Report published in November 2012. The project did not continue due to the lower demand forecast. ElectraNet noted that the project would be rescheduled to 2025, due to a lower demand forecast.[80] Eyre Peninsula Reinforcement		Regional Victoria Reactive Support: In 2012, a RIT-T commenced on this project. However, the RIT-T was never progressed due to a revised forecast in electricity use, together with the installation of two new transformers at Bendigo, the need for additional reactive power support in Regional Victoria		Supply to Southern Brisbane: In March 2012, Energex and Powerlink commenced this project. However, this project never progressed due to revised demand forecasts, showing a significant reduction in load; as well as a revision of Energex's network

79 See: https://www.transgrid.com.au/news-views/lets-connect/consultations/Documents/Project%20Assessment%20Conclusions%20Report%20QNI%20Upgrade%20AEMO%20Website%20Summary.pdf#search=rit%2Dt

80 See: https://www.electranet.com.au/projects/managing-voltages-in-the-mid-north/

Year / TNSP	ElectraNet	AEMO	TasNetworks	TransGrid	Powerlink
	Project: RIT-T Project Specification Consultation Report published in May 2012, and a Draft Report in March 2013. ElectraNet then announced that the regulatory consultation process had been put on hold until confirmation whether the load increase that was forecast, will occur.[81]		was deferred.		planning criteria for the CBD.[82]
2011	**SA-Vic (Heywood) Interconnector Upgrade: In 2011, a RIT-T on this project was started, with this concluding in January 2013, which resulted in an increased capacity of the Heywood interconnector. The increased capacity interconnector was energised in July 2016. This RIT-T was conducted in conjunction with AEMO.**		Eastern Metropolitan Melbourne Reactive Support: In 2011, AEMO commenced a RIT-T on this project. However, the RIT-T was never progressed due to a revised forecast in electricity use, which deferred the need for additional reactive power support. Eastern Metropolitan Melbourne thermal capacity: In 2011, AEMO commenced a RIT-T on this prjoect. However, the RIT-T was never progressed due to a revised forecast in electricity use, which deferred the need for		

81 See: https://www.electranet.com.au/projects/eyre-peninsula-reinforcement-project/

82 See: https://www.powerlink.com.au/Network/Network_Planning_and_Development/Current_RIT-T_consultations.aspx

Year / TNSP	ElectraNet	AEMO	TasNetworks	TransGrid	Powerlink
			additional thermal capacity. **Victorian Reliability Support: In 2011 AEMO commenced a RIT-T process to assess market benefits for increasing power transfer capability between NSW and Victoria with this process concluding in 2012.** However, later in 2012 an update was provided noting that the preferred option would not be proceed with due to a forecast drop in electricity use.[83]		

83 See: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Regulatory-investment-tests-for-transmission