REVIEW

Australian Energy Market Commission

DECISION REPORT

Last Resort Planning Power - 2014 Review

6 November 2014

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Decision 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 Australian Energy Market Commission (Commission) has determined not to exercise its last resort planning powers in 2014.

This report sets out the background to the last resort planning power, the matters the Commission has taken account when considering whether or not to exercise the last resort planning power and the reasons for its decision not to exercise the last resort planning power in 2014.

From the analysis undertaken for the 2014 review, jurisdictional planning bodies are appropriately including inter-regional transmission priorities in their planning activities. The Commission therefore does not consider it necessary to exercise the last resort planning power conferred on it under the National Electricity Rules.

Background

The interconnected transmission network is important for facilitating a secure and stable supply of electricity to consumers and supporting the National Electricity Market (NEM). Timely identification of constraints that may impact on the inter-regional transmission capability of the network is therefore crucial. An important aspect of transmission planning is to examine potential constraints in the transmission network and to consider options for alleviating those constraints when it is economically efficient to do so.

Responsibility for transmission planning in the NEM is shared between the Australian Energy Market Operator (AEMO) in its role as National Transmission Planner and jurisdictional planning bodies for each region of the NEM. With the exception of Victoria, where AEMO is the jurisdictional planning body, these bodies are the relevant transmission business in each NEM region.

Each year AEMO publishes the 'national transmission network development plan', which, among other things, identifies national transmission flow paths in the NEM. Jurisdictional planning bodies are required to take the most recent national transmission network development plan into consideration when reviewing their transmission networks and publishing their annual planning reports.

2013 transmission network development plan

To assess the need to exercise the last resort planning power in 2014, the Commission has reviewed the annual planning reports for each NEM region in light of the planning priorities identified in the 2013 national transmission network development plan.

The 2013 national transmission network development plan highlighted a number of changes in the market environment during the 2012-13 financial year compared with previous estimates. These included a decline in energy demand growth and uncertainty around carbon pricing. This led AEMO to conclude that less transmission investment is likely to be required over the 25 year outlook period.

With the exception of the Heywood interconnector upgrade, the 2013 national transmission network development plan did not identify any further requirement for augmentation of the interconnectors. Construction of the Heywood interconnector upgrade project is due to be completed in 2016.

Planning bodies in the NEM also continue to address or monitor other constraints within their networks that could affect inter-regional electricity flows. Examples include the ongoing process to examine the potential for upgrades to the interconnector between Queensland and New South Wales, currently on hold, and planning activities aimed at improving electricity flows between New South Wales and Victoria.

As the Commission did not find a lack of planning regarding inter-regional transmission infrastructure, it has decided not to exercise the last resort planning power in 2014.

Last resort planning power

The last resort planning power conferred on the AEMC complements the transmission planning responsibilities of AEMO and jurisdictional planning bodies. Being a last resort mechanism, the last resort planning power is designed to be utilised only where there is a clear indication that regular planning processes have resulted in a gap in the planning of inter-regional transmission infrastructure.

The Commission has adopted a three-stage approach to the last resort planning power. In stage one, analysis is undertaken to determine whether any identified inter-regional flow constraints are sufficiently addressed by the jurisdictional planning bodies in their planning activity, or whether there is a 'planning gap'. If a gap were identified, the purpose of stage two would be to more closely examine the particular inter-regional flow path involved and the estimated economic impacts of the constraint. If the Commission was to conclude that making a direction may meet the National Electricity Objective, stage three would focus on who should be directed to undertake the regulatory test for investment for transmission and identify potential solutions that could be examined.

The Commission is also required to take into account the last resort planning power guidelines in its assessment. These guidelines are updated every five years and published on the AEMC website. The Commission intends to undertake a review of the last resort planning power guidelines, commencing in late 2014, which will include updating the cross-references to the National Electricity Rules in addition to consideration of any other relevant issues raised by stakeholders.

The National Electricity Rules require the Commission to report annually on the exercise of the last resort planning power. In the four years that the Commission has conducted this review, it has not found the need to exercise this power.

Contents

1 Transmission planning and the last resort planning power

The following Chapter provides the relevant background on role of the transmission network in the NEM and the process that market participants take regarding planning of the transmission network. The interaction between the national transmission planning body, AEMO, and the jurisdictional planning bodies is outlined in the section on long-term planning.

The need for the last resort planning power arises because interconnectors span the boundaries between the transmission networks, and require some degree of joint planning. This joint planning reduces the risk that jurisdictional planning bodies focus only on their own network. This Chapter also provides an overview of the last resort planning power and the Commission's approach.

1.1 Role of transmission network

Transmission lines physically connect power plants to each other, to large demand customers and to distribution networks. Thus the transmission network plays a crucial role in maintaining the security of the power system, as well as, in transporting electricity from centres of generation to places where it is ultimately consumed.

The transmission network also physically connects the five regions that make up the national electricity market (NEM) and enables electricity to flow across regional boundaries. In this way, the interconnected infrastructure of the market supports the wholesale electricity market where participants buy and sell electricity and allows inter-regional trade to occur.[1]

Therefore, the interconnected transmission network operating at optimum efficiency contributes to the National Electricity Objective (NEO) through the efficient investment in, and efficient operation of and use of, electricity services for the long-term interests of consumers.

However, bottlenecks on the transmission network, termed 'constraints', can impact on the network's ability to transfer electricity, including between regions. This can limit the benefits of interconnection and can create risks for generators and retailers.[2]

1.2 Transmission planning in the national electricity market

Transmission infrastructure is expensive to build. This is often due to the large distances and high cost components required. Investment decisions therefore need to be carefully assessed as costs will ultimately be borne by consumers. Decisions about

1 Further information on interconnection and the main interconnectors in the NEM may be found in sections A.1 and A.2, of Appendix A of this report.

2 Further information on the network constraints and their effect on the transmission network may be found in sections A.3–A.5 of Appendix A of this report.

augmenting the transmission network also need to be taken in a timely manner, in order to reduce the risk of future transmission network limitations.

Not all network constraints will have the same market impact. Costs and benefits associated with augmenting the transmission infrastructure therefore need to be weighed, in order to focus on alleviating those constraints which have a significant market impact. That is, the market benefit of alleviating the constraint needs to outweigh the change in transmission costs as a result of the network augmentation.

Transmission planning is the process of making transmission network investment decisions, so that augmentations take place in a cost-effective and timely manner.

At a high level, roles and responsibilities in connection with transmission planning include:

- planning – long-term and short-term;
- project specific planning and/or investment decisions; and
- implementation of investment.

Long-term and short-term planning

Long-term, strategic planning is undertaken by AEMO in its role as the national transmission planner. In this capacity, each year AEMO must publish the National Transmission Network Development Plan (referred to as the transmission network development plan for this report).

The transmission network development plan provides a strategic vision for the development of the NEM transmission network as a whole. In particular, it focusses on the major inter-regional transmission flow paths. That is, those areas of the transmission network connecting major generation or demand centres. Its objective is to facilitate the development of an efficient national electricity network that considers potential transmission and generation investments. The minimum planning period for the transmission network development plan is 20 years.[3]

Long-term planning involves a number of activities, including the development of the different scenarios to be used for planning purposes. These scenarios can cover a range of different economic and government policy assumptions, demand forecasts and also generation scenarios.

In addition to the transmission network development plan, AEMO publishes a number of documents that inform and assist in the planning process. These documents include:

- National Electricity Forecast Report – proving annual energy and maximum demand forecasts over the next ten years for each of the five regions in the NEM.

3 NER clause 5.20.2(c)(1). However, AEMO's 2012 and 2013 national transmission development plans both have longer planning horizons of 25 years.

- Electricity Statement of Opportunities – providing an assessment of supply adequacy in the NEM over the next ten years, highlighting opportunities for generation and demand-side investment. This document is complemented by the Power System Adequacy Report, which assesses the electricity supply outlook for the next two years.

- NEM constraint report – containing details on constraints in the transmission network.

This high-level, NEM-wide planning is complemented by more detailed, shorter-term planning for individual NEM regions. Responsibility for this type of planning activity lies with jurisdictional planning bodies.

The NER imposes obligations on jurisdictional planning bodies to provide assistance to AEMO in connection with the performance of national transmission planning functions.[4] These bodies are defined as 'the entity nominated by the relevant Minister of a participating jurisdiction as having transmission system planning responsibility in that participating jurisdiction'. With the exception of Victoria, where AEMO has been nominated as the jurisdictional planning body, the relevant transmission businesses are responsible for transmission planning activities within their respective regions as outlined in Table 1.1.

Table 1.1 Overview of jurisdictional planning bodies

NEM region	Jurisdictional planning body
Queensland	Powerlink
New South Wales (and ACT)	TransGrid
Victoria	AEMO
South Australia	ElectraNet
Tasmania	TasNetworks

The NER prescribe that each transmission business must undertake an annual planning review. The purpose of this review is for a transmission business to analyse the expected future operation of its transmission network, taking account of forecast future demand and generation, demand-side and transmission developments and other relevant data, and to consider the potential for network augmentations or non-network alternatives to augmentations. The minimum planning period for the purposes of this review is ten years.[5]

4 These jurisdictional planning bodies are typically transmission network service providers for the purposes of the NER.

5 NER clause 5.12.1(c).

Each jurisdictional planning body must publish an Annual Planning Report, which describe the network developments plans relevant to the transmission networks within its NEM region. The annual report must be published before 1 July each year.[6]

Transmission businesses are required to take the most recent transmission network development plan into account when conducting their annual planning review. When a transmission business proposes certain augmentations to the network, it must explain how the proposed augmentations relate to the most recent transmission network development plan and the development strategies for current or potential national transmission flow paths specified in the development plan.

This framework seeks to ensure coordination between the planning priorities identified in the transmission network development plan regarding inter-regional flow paths and the planning activities undertaken by jurisdictional planning bodies for each jurisdiction. In addition to inter-regional flow paths, the transmission businesses will typically also consider upgrades that primarily affect transmission flow paths within their regions, that is, intra-regional.

The long-term and short-term planning undertaken by AEMO and the transmission businesses is complemented with the last resort planning power, conferred on the AEMC (see section 1.3).

Project specific planning and/or investment decisions

Project specific planning relates to a particular investment need and culminates in a particular investment decision. The NER require that transmission businesses must apply a regulatory investment test for transmission for any augmentation projects with an estimated cost of more than $5 million.[7]

The purpose of this regulatory investment test is to identify the transmission investment option that maximises the net economic benefit to all those who produce, consume and transport electricity in the market, after performing cost-benefit analysis on a number of credible options. The NER define a 'credible option' as an option or group of options that:

- addresses the identified need;
- is, or are, commercially and technically feasible; and
- can be implemented in sufficient time to meet the identified need.

The costs associated with options for transmission augmentation must be weighed against the benefits they are likely to bring to the market. Under the current regulatory investment test, investments may be undertaken to either meet reliability standards, or to deliver a net market benefit, for example, economic expansion.

6 NER clause 5.12.2(a).

7 The application of the regulatory investment test for transmission is also subject to a number of exceptions under clause 5.16.3(a) of the NER.

The NER also requires the regulatory investment test to consider a number of classes of market benefits that could be delivered by each credible option, such as:

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in the costs for parties, other than the transmission proponent, due to:
  - differences in the timing of new plant;
  - differences in capital costs; and
  - differences in operating and maintenance costs;
- changes in network losses;
- changes in ancillary service costs; and
- competition benefits.

The procedure that a transmission proponent must follow in conducting a regulatory investment test is also outlined in the NER. Following completion of the regulatory investment procedure, a project assessment conclusions report is published setting out the matters analysed in the draft report and a summary of, and the transmission proponent's response to, submissions received from interested parties.

Implementation of investment

The actual implementation of the investment follows on from the investment decision. It involves a number of detailed activities in order to construct and then commission the asset, such as:

- obtaining planning permissions;
- outage planning, as construction of the new asset is likely to require outages of other equipment in order to connect it to the network;
- detailed design;
- procurement of materials and resources;
- civil works and construction; and
- commissioning, that is, the final stage of the implementation of the investment, when it is placed into use.

1.3 The last resort planning power

The last resort planning power was added to the NER in response to a concern that there may be insufficient incentives on jurisdictional planning bodies to adequately consider inter-regional network developments. The obligations relating to the last resort planning power are located under rule 5.22 of the NER.

> ## 5.22 Last resort planning power
>
> **Purpose**
>
> (b) The purpose of a *last resort planning power* is to ensure timely and efficient *inter-regional transmission* investment for the long term interests of consumers of electricity.

Under the last resort planning power, the AEMC has the power to direct a participant to undertake a regulatory investment test if the Commission considers there has been insufficient consideration of an inter-regional transmission constraint in the planning activities of a jurisdictional planning body. Specifically, under rule 5.22(c) of the NER:

> **AEMC last resort planning power**
>
> (c) The *AEMC* may, in accordance with this rule 5.22, direct one or more *Registered Participants*:
>
> (1) to identify a potential transmission project and apply the *regulatory investment test for transmission* to that project; or
>
> (2) to apply the *regulatory investment test for transmission* to a potential transmission project identified by the *AEMC*.

Under the last resort planning power, the Commission cannot direct that a certain investment occurs, but may require a person to apply the regulatory investment test for transmission to a project, which would address an identified inter-regional transmission constraint. Rule 5.22(g) of the NER outlines the those considerations that the Commission must have regard to in deciding whether to exercise the last resort planning power.

> **Relevant considerations**
>
> (g) In deciding whether or not to exercise the *last resort planning power* the *AEMC* must:
>
> (1) identify a problem relating to *constraints* in respect of *national transmission flow paths* between *regional reference nodes* or a potential transmission project (**the problem** or **the project**);
>
> (2) make reasonable inquiries to satisfy itself that there are no current processes underway for the application of the *regulatory investment test for transmission* in relation to the problem or the project;
>
> (3) consider whether there are other options, strategies or solutions to address the problem or the project, and must be satisfied that all such other options are unlikely to address the problem of the

project in a timely manner;

(4) be satisfied that the problem of the project may have a significant impact on the efficient operation of the *market*; and

(5) be satisfied that but for the *AEMC* exercising the *last resort planning power*, the problem or the project is unlikely to be addressed.

Being a last resort mechanism, the last resort planning power is designed only to be utilised where there is a clear indication that regular planning processes have resulted in a planning gap regarding inter-regional transmission infrastructure.

The NER require the Commission to report annually on the exercise of the last resort planning power. The Commission has not exercised the last resort planning power since the last resort planning power was conferred on it in 2007.

1.4 Commission's approach to exercising the last resort planning power

Taking the NER requirements into account, the Commission has adopted a three-stage approach to the last resort planning power.

At the first stage, analysis is undertaken to determine whether any identified inter-regional flow constraints are being addressed by the jurisdictional planning bodies in their planning activities or whether there is a 'planning gap'. This exercise is done by analysing and comparing the following documents:

- the national transmission network development plan for the current and previous years – 2012 and 2013 for this current review;
- the national electricity market constraint report for 2013;
- the jurisdictional planning bodies 2014 annual transmission planning reports; and
- any other relevant documentation, for example, current regulatory tests for investment for transmission projects.

The second stage of the process is only undertaken by the AEMC if the first stage identifies a constraint on an inter-regional flow path that may not have been adequately examined by the relevant jurisdictional planning bodies. This second stage would focus on the particular flow path identified. The goal would be to collect all the information for a more in depth assessment of the identified potential planning gap. During the second stage of the last resort planning power, the AEMC would request information from AEMO and the relevant jurisdictional planning bodies using the process in the last resort planning power guidelines. The AEMC would use this information to more closely examine this inter-regional flow path and the estimated economic impacts of the constraint. If the Commission was to conclude that making a direction may meet the National Electricity Objective, it would initiate the third stage.

At the third stage of the process, the AEMC would request submissions from stakeholders. These submissions would be used to determine what information would need to be included in any direction that would be made to either the relevant jurisdictional planning body or another registered participant. The third stage assessment of the last resort planning power would also focus on who should be directed to undertake the regulatory test for investment and potential solutions that could be examined.

The current guidelines were published by the AEMC in 2010. Under the guidelines, there is a requirement for them to be reviewed and updated by the Commission every five years.[8] The Commission notes that there are a number of out-of-date cross-references to the NER in the current version of the guidelines. These have arisen as a result of the making of the distribution network planning and expansion framework rules, which moved the NER location of the last resort planning power obligations within Chapter 5. As such, the Commission intends to undertake a review of the last resort planning power guidelines, commencing in late 2014, which will encompass correcting these cross-references, in addition to consideration of any other input from stakeholders.

8 The current last resort planning guidelines may be found at www.aemc.gov.au/Australia-s-Energy-Market/Market-Legislation/Electricity-Guidelines-and-Standards.

2 Commission's considerations and conclusions

This chapter outlines the Commission's considerations and conclusions on whether to exercise the last resort planning power in 2014. This analysis includes a:

- review of the 2012 and 2013 transmission network development plans, including:
  - changes since the 2012 transmission network development plan; and
  - an overview of the 2013 transmission network development plan;
- review of 2013 NEM constraint report.

The conclusion provided at the end of this Chapter also draws on the analysis of each interconnector and main transmission corridor outlined in Appendix B to G of this report.

2.1 Review of the 2012 and 2013 transmission network development plans

The NER require the AEMC to review the transmission network development plan for the current and previous year when considering the exercise of the last resort planning power. This chapter provides a summary of the:

- main changes between the 2012 and 2013 transmission network development plans; and
- 2013 transmission network development plan and its key findings, in particular where they relate to inter-regional transmission priorities.

The transmission network development plan is concerned with modelling the development of the critical national transmission flow paths. That is, those areas of the transmission network connecting major generation or demand centres.

The transmission network development plan seeks to influence transmission investment by:

- providing a national focus on market benefits and transmission augmentations to support an efficient power system;
- proposing a range of plausible future scenarios and exploring their electricity supply industry impacts, with an emphasis on identifying national transmission network constraints under those scenarios, and providing a consistent plan that identifies their transmission network needs; and
- identifying network needs early to increase the time available to identify non-network options, including demand-side and generation options.

For planning purposes, the transmission network development plan has been split into sixteen zones, referred to as 'transmission zones'. These zones capture differences in generation technology capabilities (for example, wind capacity) and differences in costs (for example, caused by the differences in connection costs) that exist within the NEM region.

The following figure identifies the transmission zones and the main flow paths between these zones.

Figure 2.1 National transmission zones and flow paths

NTNDP zone	Zone abbreviation
North Queensland	NQ
Central Queensland	CQ
South West Queensland	SWQ
South East Queensland	SEQ
Northern New South Wales	NNS
Central New South Wales	NCEN
Canberra	CAN
South West New South Wales	SWNSW
Latrobe Valley	LV
Melbourne	MEL
Country Victoria	CVIC
Northern Victoria	NVIC
Adelaide	ADE
Northern South Australia	NSA
South East South Australia	SESA
Tasmania	TAS

Source: AEMO, *National Transmission Network Development Plan*, December 2012, pp1-4 and 1-5.

2.1.1 Changes since the 2012 transmission network development plan

The 2013 transmission network development plan considered lower projected electricity consumption growth than forecast in 2012. AEMO identified the following factors as being important in its revised forecasts:[9]

- Continued increase in domestic rooftop photovoltaic installations as a result of feed-in-tariffs and lower system installation prices.
- Lower-than-expected growth in most industrial sectors.

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9 AEMO, *2013 National transmission network development plan*, p2.

- Higher estimated energy efficiency savings from measures implemented in changes to building standards and regulations.

- A higher estimate of customer response to extreme wholesale price events based on analysis of historical demand-side participation behaviour.

In relation to rooftop photovoltaic installations, AEMO estimated that approximately 774 MW was installed in the NEM in 2012-13. For the purposes of its modelling, photovoltaic generation is treated as a demand offset contributing to the reduction in forecast demand.

AEMO also observed a 3.5 percent reduction in actual electricity consumption in the first quarter of 2013-14 (from 1 July to 1 September 2013). As a result, AEMO published an update to the National Electricity Forecasting Report in November 2013. The 2013-14 NEM consumption forecasts were revised downwards by 1.3 percent.

AEMO noted that the other key modelling inputs and assumptions, including generation costs and technical parameters, remained the same as those used in the 2012 transmission network development plan. As noted above, the carbon price scenarios used in the 2013 development plan differ from those used in 2012.

2.1.2 Overview of the 2013 transmission network development plan

This section provides a summary of the modelling approach used in the 2013 transmission network development plan.[10]

The modelling uses the latest set of electricity consumption and generation cost assumptions published by AEMO for a medium-growth scenario. The 2013 transmission network development plan modelled the renewable energy schemes current at the time and two carbon price trajectories, including a:

- **Carbon price scenario** – that reflected the legislation at the time of publication in December 2013, and a lower expectation of carbon prices linking to an international trading scheme. This scenario was a revision of the Australian Treasury core projection and was used in the 2012 transmission network development plan.[11]

- **Zero carbon price scenario** – where the explicit price on carbon emissions is removed from 2014 onwards. This scenario modelled generation dispatch without an explicit carbon emissions price, recognising the Federal Government's intention to repeal the price on carbon. It did not model alternative ways of achieving carbon emissions reductions, such as the Federal Government's Direct Action plan.

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10 AEMO, *2013 National transmission network development plan*, p1.

11 Note: since publication of the 2013 transmission network development plan in December 2013, from 1 July 2014 the legislated price on carbon was removed.

Both scenarios modelled the large-scale renewable energy target at the current legislated level. The 2013 transmission network development plan included generation and transmission developments that have been committed since the 2012 development plan.

A detailed description of the modelling methodology and the assumptions used in the transmission network development plan are published on AEMO's website.[12] The 2013 transmission network development plan modelling used the input assumptions listed under the "planning" scenario.

12 AEMO's 2013 planning assumptions webpage may be found at www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions and includes consistent input data and assumptions to enable the modelling of five scenarios.

Table 2.1 The planning scenario for the 2013 transmission network development plan

Scenario	Economic				Greenhouse			
	Economic growth	Commodity prices	Productivity growth	Population growth	Reduction target (below 2000 levels)	Carbon price	National renewable energy target scheme	Green power sales
Planning	National economic growth continues at currently predicted levels. Global recovery continues with ongoing growth in the demand for Australian commodities particularly resources.	Medium	Medium	Medium	Five percent reduction by 2020 and an 80 percent reduction by 2050.	Treasury core scenario starting at approximately \$16/t-CO2-e on 1 July 2014. Zero carbon price from 2014 onwards and no alternative ways of achieving carbon emissions reductions modelled.	LRET[a] remains in place to 2037-38 with no significant changes from the two-yearly reviews. SRES[b] remains in place to 2030 with currently announced reductions to the STC[c] multiplier[d].	No growth.

AEMC: adapted from comparison of the 2012 and 2013 transmission network development plans.

a. Large-scale renewable energy target.

b. Small-scale renewable energy scheme.

c. Small-scale technology certificates.

d. Also referred to as the Federal Solar Credits rebate renewable energy certificate (REC) (STC) multiplier.

Transmission development outlook at 2020-21

AEMO's analysis focussed on assessing the adequacy of the main transmission network to reliably support major power transfers between generation and demand centres. The key observations from the 2013 transmission network development plan included:[13]

- Compared to the 2012 development plan, the reduced growth in electricity consumption results in reduced network constraints in all regions, with the exception of Queensland where the electricity consumption forecast increased.
- The transmission network development plan modelling did not identify a requirement for major investment in inter-regional augmentations following the completion of the Victoria–South Australia, Heywood interconnector augmentation.
- AEMO estimated that a capital cost of around $3.5 billion would be required to remove the identified network constraints on the main transmission network under both carbon price scenarios.
- AEMO has not identified a need for further network control ancillary services beyond the New South Wales requirements that are currently being addressed by AEMO under contract.

AEMO noted that for the 2013 transmission network development plan that consumption growth in each zone was expected to be met by generation in the same zone. This led to minimisation of overall generation and transmission costs. However, if future generation development differed from the projected investment patterns, other network constraints not accounted for in the 2013 development plan may arise.

Over the short-term, AEMO identified a number of reliability-driven network constraints through its transmission network development plan modelling. Where these limitations were likely to influence the main corridors on the transmission system, they have been discussed in the analysis on each interconnector in Appendix B to G of this report.

Transmission development outlook to 2037-38

Under the long-term transmission development outlook, AEMO's modelling identified an additional six emerging reliability limitations and 12 potential economic dispatch limitations by 2037-38.[14] These same limitations were identified under both the carbon price and zero carbon price scenarios. Both types of limitation arise because the network capability limits the ability of power transfers on specific parts of the network.

The distinction between the two types of limitation is that the potential economic dispatch limitations do not give rise to a loss of supply. Although more expensive

13 AEMO, *2013 National transmission network development plan*, pp9-10.

14 AEMO, *2013 National transmission network development plan*, p19.

generation plant may be dispatched ahead of less expensive plant, network capability is sufficient to meet forecast consumption levels. Potential economic dispatch limitations have been identified mainly at times of high wind generation output.

Emerging reliability limitations are those that lead to a loss of supply that cannot be resolved by rescheduling generation.

Further information about those transmission network constraints that are expected to influence the NEM interconnectors, or main transmission corridors are outlined in Appendix B to G of this report.

2.2 Review of the 2013 constraint report

AEMO also annually publishes the National Electricity Market Constraint Report. This report contains details about constraint equation performance in the preceding calendar year. It also provides information on the drivers of constraint equation changes, analysis of binding and violating constraint equations, market impact of constraint equations and those equations that set interconnector limits.

As the constraint report is published after the transmission network development plan, jurisdictional planning bodies have had the ability to use or consider this information to inform their annual planning reports.

For the purpose of consideration of the last resort planning power, the Commission has analysed the 'system normal'[15] constraints that were most binding on interconnector limits, in terms of the number of hours, in each direction. The top three binding constraints in each direction for each interconnector are outlined in the analysis on the individual interconnectors in Appendix B to G.

In addition to those equations setting interconnector limits, constraints can also be listed according to their market impact. The market impact value seeks to quantify, in dollar value, the impact of a particular constraint.[16] The top three market impacts for each interconnector from the 2013 constraints report in each direction is also outlined in the analysis on the individual interconnectors in Appendix B to G of this report.

It is important to note that the number of hours a constraint may bind on an interconnector may not necessarily correlate with its market impact. Further, given the interconnectedness of the transmission system, often a binding constraint on an interconnector will also appear in the constraint equations of other interconnectors. For example, this occurs in Victoria where the system normal constraint to avoid overloading the South Morang 500/330 kV (F2) transformer for no contingencies, also

15 System normal constraints do not include constraints caused by outages of transmission elements or frequency control ancillary service requirements.

16 The market impact is calculated by adding up the marginal values from the marginal constraint cost re-run. To that end, the constraint is relaxed marginally (by 1 MW). This will result in a different dispatch pattern, with different associated costs, compared to the situation under the full constraint. This is done for each dispatch interval during the number of hours a constraint was binding. These values are subsequently added up to provide a total marginal market impact.

appears in the constraint equations for the Heywood, Basslink, Murraylink and Victoria–New South Wales interconnectors.

Where a particular constraint is being addressed by AEMO or a jurisdictional planning body, commentary on the likely impacts on the constraint going forward are also included in the analysis of each interconnector.

2.3 Conclusions on the exercise of the last resort planning power for 2014

In summary, the Commission is satisfied there are no transmission network constraints on any NEM interconnectors that are not being addressed by the relevant jurisdictional planning bodies, or AEMO, in their annual planning reports.

In reaching this conclusion, the Commission has taken into consideration:

- advice provided by AEMO in the form of the transmission network development plans for 2012 and 2013;
- the transmission annual planning reports published by the transmission businesses for each NEM jurisdiction; and
- other matters relevant to making a decision, including review of the NEM constraints report and any regulatory investment tests for transmission being undertaken.

The Commission is satisfied that each transmission network constraint identified by AEMO in its 2013 transmission network development plan is being addressed in the relevant jurisdiction by the transmission business responsible for transmission planning. The analysis supporting this conclusion is contained in Appendix B to G. These appendices provide an overview of each NEM interconnector and outline the transmission network constraints identified by AEMO in its transmission network development plan, and how the jurisdictional planning body plans to address these limitations.

There is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a participant under the last resort planning powers conveyed on it under the NER.

The Commission therefore has determined not to exercise the last resort planning power in 2014.

A Background: interconnection and constraints

A.1 Interconnection

Almost 40,000 km of transmission lines and associated infrastructure make up the physically interconnected NEM transmission network. The network supplied approximately 184,000 gigawatt hours of energy to both business and households from Far North Queensland to Tasmania in 2012-13.[17]

Physical interconnection allows electricity to flow across the entire network, facilitating the NEM as a single market. Interconnection has a number of efficiency benefits, as it:[18]

- allows electricity in lower priced regions to flow to higher priced regions, thereby reducing the cost of meeting demand in the NEM and the degree of price separation between regions;
- can contribute to a reduction of price volatility in regions;
- enables retailers to access cheaper sources of generation, thereby increasing competition between generators and retailers (to the benefit of consumers); and
- allows optimisation of investment in generation and transmission as interconnection may defer the need for investment in generation or transmission which may otherwise have taken place.

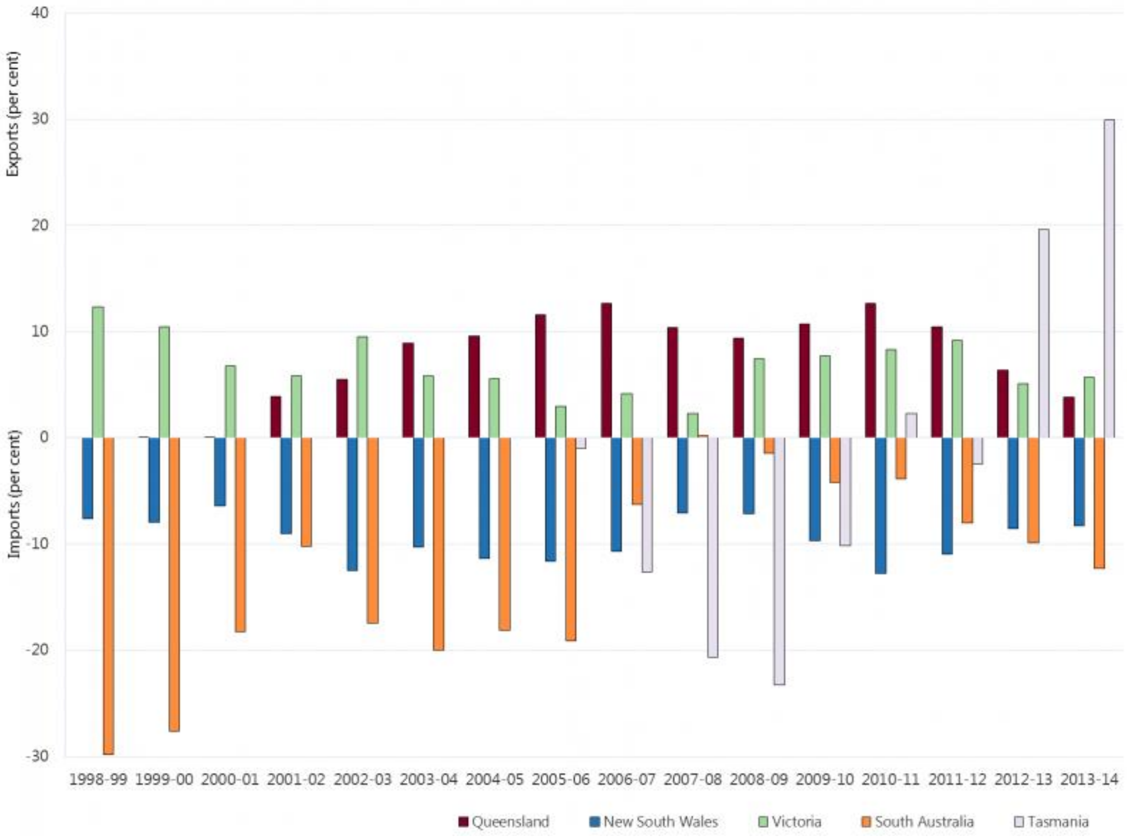
Interconnectors also contribute to security of supply across NEM regions as regions can draw upon a wider pool of reserves.

The level of interconnection in the NEM has facilitated inter-regional trade between NEM regions. Depending on local circumstances - such as available generation (including the cost of generation) and levels of demand - regions are either net importers or net exporters of electricity. The following diagram expresses inter-regional trade, in net flows, as a percentage of regional energy demand for each region of the NEM.

17 AEMO, *Annual report 2013*, September 2013, p11.

18 See also: Productivity Commission, *Electricity Network Regulation, Final Report*, Chapter 16: The role of interconnectors.

Figure A.1 **Inter-regional trade, in net flows, as a percentage of regional demand**



Source: Industry statistics on the AER website. Available from www.aer.gov.au/industry-information/industry-statistics (last viewed 7 October 2014)

The growing share of electricity generation coming from renewable energy sources is likely to increase the potential benefits of interconnection. This is because:

- sources of renewable energy are often further removed from centres of demand than conventional generation;
- the potential for price separation between regions is likely to increase as a result of lower-cost renewable energy; and
- the intermittency of renewable energy sources such as wind and solar requires sufficient complementary generation from other power sources in order to secure a reliable supply. This complementary generation may be provided by a generator in another region.

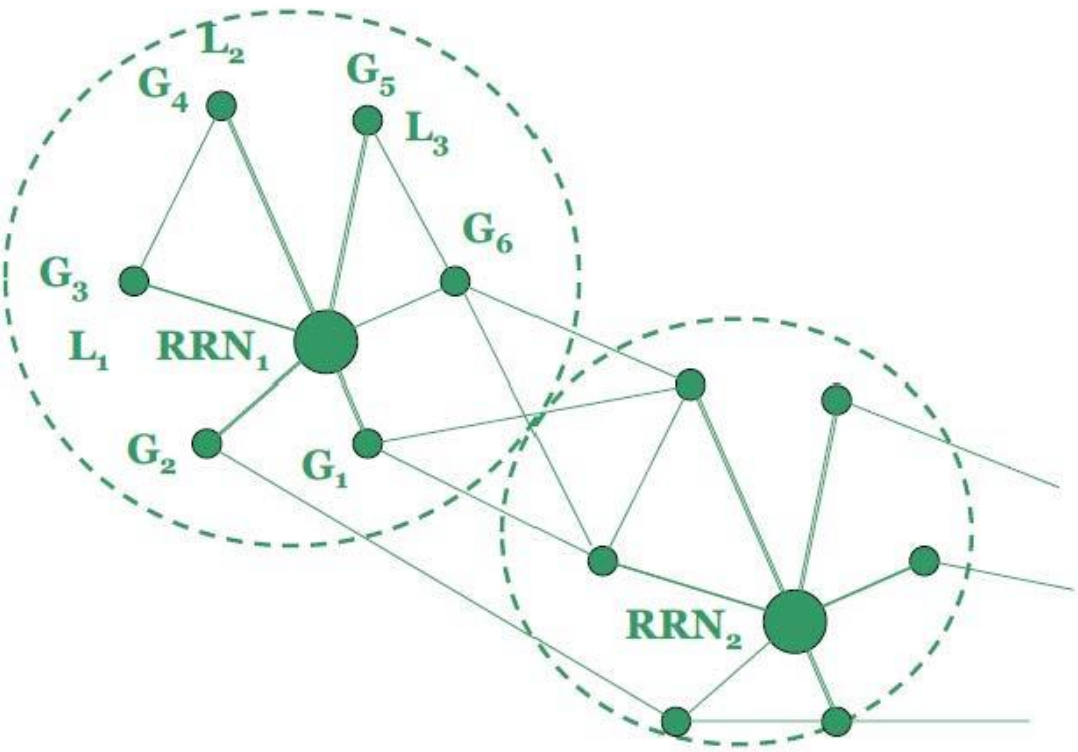
The importance of the transmission network in the functioning of the NEM leads to the need for it to be reliable, as outages or failures of the network can be disruptive and costly.

Transmission businesses operate the transmission networks in the five NEM regions and are responsible for ensuring a reliable supply of electricity over the transmission system to consumers in their respective regions. These businesses also need to comply with transmission reliability and system security requirements which guide how they plan and operate their networks.

A.2 Interconnectors

For the purpose of network planning, an 'interconnector' refers to transmission network infrastructure that enables electricity to be carried across NEM regional boundaries. In this sense, interconnectors consist of transmission infrastructure located on each side of a regional boundary, connected by a set of high-voltage transmission lines or cables. This infrastructure cannot necessarily be distinguished from other parts of the transmission network. Schematically, this can be represented by the following diagram (Figure A.2).

Figure A.2 Stylised representation of interconnectors as cross-border infrastructure

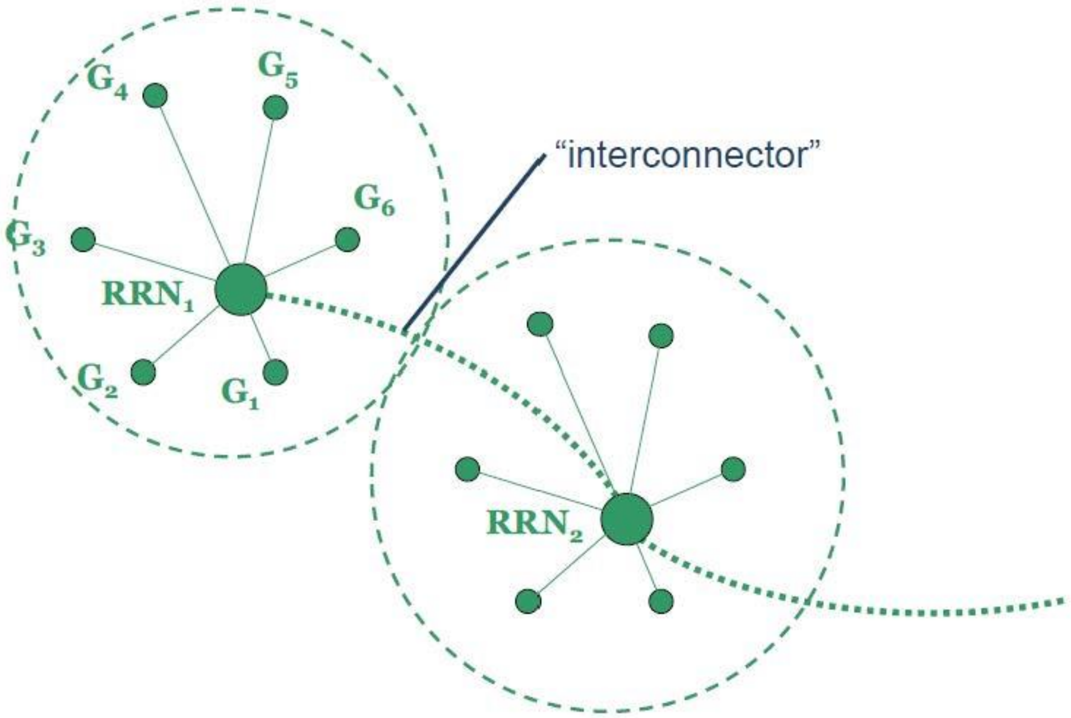


Note: 'RRN' refers to regional reference node, 'G' to generator and 'L' to load (demand) centres

Source: AEMO, Electricity network regulation – AEMO's response to the Productivity Commission issues paper, 21 May 2012, p30.

For the purpose of dispatch and settlement, interconnectors are a notional concept, connecting two regional reference nodes in different regions of the NEM, as illustrated by Figure A.3. In this sense, they are a mathematical representation of the movement of electricity from one regional reference node to another. That is, the interconnectors represent the transmission flow-paths within each NEM region that link the two regional reference nodes. For this reason, the Commission has regard for the 'physical' interconnectors, in addition to the transmission flow-paths and/or corridors leading up to the interconnectors when evaluating the last resort planning power.

Figure A.3 Treatment of interconnectors for market purposes



Source: AEMO, Electricity network regulation – AEMO's response to the Productivity Commission issues paper, 21 May 2012, p31.

There are two types of interconnectors in the NEM: regulated and unregulated (merchant) interconnectors.[19]

A regulated interconnector is an interconnector that forms part of a transmission business's regulated assets.[20] The transmission business owning the interconnector receives a regulated annual revenue based on the value of the asset, set by the AER, regardless of the actual usage. The revenue is collected as part of the network charges included in the bills of electricity end-users.

An unregulated (or merchant) interconnector derives revenue by trading on the spot market. This is done by purchasing energy in a lower priced region and selling it to a higher priced region, or by selling the rights to revenue traded across the interconnector. Unregulated interconnectors are not required to undergo the regulatory test evaluation. The only unregulated interconnector currently operating in the NEM is Basslink connecting Tasmania and Victoria.

19 See: AEMO, Interconnectors. Accessed via: www.aemo.com.au/Electricity/Network-Connections/Interconnectors.

20 In general, this means the interconnector has passed the Regulatory Investment Test for Transmission, see section 3.1.

Each interconnector will have a certain capacity which establishes an upper limit to the amount of electricity that can be carried across the interconnector. In practice, limits elsewhere in the network are the principal reason that the actual transfer capacity is often set at lower levels. This also explains why actual capacity may vary between seasons, between peak and off-peak periods and according to flow directions.

The current interconnectors in the NEM, including their regulatory status, are listed in table A.1.

Table A.1 Interconnectors in the NEM

Name	Region	Regulated or unregulated
QNI	Between Queensland and New South Wales	Regulated
Terranora (Directlink)	Between Queensland and New South Wales	Regulated
VIC to NSW	Between Victoria and New South Wales	Regulated
Heywood	Between South Australia and Victoria	Regulated
Murraylink	Between South Australia and Victoria	Regulated
Basslink	Between Tasmania and Victoria	Unregulated (Merchant)

Source: AEMO, Interconnector performance, Quarter March-May 2014, 17 July 2014.

Figure A.4 illustrates where the interconnectors, being those elements of the transmission network that cross state boundaries are physically located.

Figure A.4 Location of interconnectors in the NEM

Source: An introduction to Australia's National Energy Market, July 2010.

AEMO publishes details on the performance of interconnectors on a quarterly basis, which assists in scheduling and dispatch functions.[21]

A.3 Network constraints

The ability of the network to carry electricity (the 'transfer capability') is in practice affected by a range of factors.[22]

Outages or maintenance operations may for example cause generators or particular network elements to be unavailable, or operated at reduced capacity for a certain period of time.

Also, individual network elements have technical design limitations. When a particular element in the network reaches its limits and cannot carry any more electricity, it is 'congested'. Congestion limits are not only determined by the normal flow of electricity across that element itself, but also by the flow that would occur following a major contingency event occurring elsewhere in the network. For example, a trip of an element elsewhere in the system may cause additional electricity to flow in the first element.

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21 These Interconnector Quarterly Performance Reports are available via: http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Network-Operations/Interconnector-Quarterly-Report

22 See also AEMC, *Congestion Management Review*, 2008, p50.

Congestion is a normal feature of power systems and occurs because there are physical limits, needed to maintain the power system in a secure operating state, such as:

- the capacity of elements in the network;
- thermal limits: these refer to the heating of a transmission element. The heating of transmission lines, for example, increases as more power is sent across them, which causes the lines to sag closer to the ground. Thermal limits are used for managing the power flow on a transmission element so that it does not exceed a certain rating; and
- stability limits: these include limits to keep the NEM generating units operating synchronously and in a stable manner (for example within design tolerances for voltage), and transmission elements operating in a stable manner.

Violating these limits may damage equipment, cause dangerous situations for the general public and may ultimately lead to supply interruptions.

Constraints in transmission infrastructure further removed from regional boundaries can impact on the ability of electricity to flow across regional boundaries. The potential for inter-regional trade is therefore not only influenced by the limits of the interconnector capacity itself, but also by constraints occurring in parts of the network further removed from the actual interconnector infrastructure. In other words: *intra*-regional transmission constraints can impact on *inter*-regional transmission flows.

A.4 Constraints and the dispatch process

The dispatch process determines which generators will be required to generate electricity, and how much they will be required to generate in order to meet demand. This process is managed by AEMO. To that end, AEMO operates the National Electricity Market Dispatch Engine (NEMDE), a computer program designed to optimise dispatch decisions.

NEMDE dispatches generation on a five-minute interval basis, taking into account a variety of parameters and variables. Among these are generator offers, but also the thermal, voltage and stability limits of the network. Within these parameters, NEMDE calculates the optimal market solution for dispatch. That is, the lowest cost solution for dispatch of generation in order to meet demand.

Network constraints affecting the network transfer capability are 'translated' for the purpose of operating NEMDE into 'constraint equations'. Each network constraint equation is a mathematical representation of the way in which different variables affect flows across particular transmission lines. A network constraint is thus a limitation imposed on the market dispatch process accounting for the physical restrictions necessary for secure operation of the system.

Box A.1: Constraint equations

The convention for network constraints used in NEMDE is to include terms that can be controlled (optimised) by AEMO through dispatch on the left hand side (LHS) of the equation, and terms that cannot be controlled by AEMO through the dispatch on the right hand side (RHS) of the equation.

Hence, generator output terms and interconnector flow terms tend to appear on the LHS, while terms relating to the limits of particular transmission elements tend to appear on the RHS.

For example, a constraint of the form:

$\alpha G + \beta IC \leq 500$

means the weighted dispatch of the generator (G) and interconnector (IC) cannot exceed 500 MW. The α and β represent the coefficients, or weights, that denote to what extent the G and IC contribute to the constraint.

All the relevant conventions for constraint building and constraint naming for the use of constraint equations in AEMO's market systems are published in AEMO's *Constraint Formulation Guidelines* and *Constraint Naming Guidelines*.

Regions of the NEM are identified through the use of single character identifiers (for example: Queensland = Q; New South Wales is N, and so on). Interconnectors are identified as 'I'. Similarly, various substations have their own identifiers. For example, substation Buronga = BU; substation Darlington Point is DP; Mount Beauty = MB, and so on. Transmission lines between substations are noted by the use of the grouped IDs of the substations between which the line runs. For example: the ID 'BUDP' for example refers to the Buronga-Darlington Pt 220 kV line.

When there are no outages in a region (a 'system normal' condition), this is identified as 'NIL'. Hence, N-NIL means: New South Wales region: system normal.

Similarly, there are naming conventions for the causes of constraints, such as single and multiple plant outages and constraints caused by thermal (noted by an '>'), voltage (noted by an '^') and stability limits (noted by an ':').

Constraint sets are a group of constraint equations required to identify a particular network condition.

As a general rule, constraint set equations names identify:

- the region where the constraint exists or the two regions for a interconnector limit ('region ID');
- the cause of the constraint ('cause ID');

- the system condition ('outage ID').

For example: I-BCDM_ONE means: outage of one Bulli Creek - Dumaresq 330 kV line. And: Q^NIL_GC means: Gold Coast system normal voltage stability limit.

The naming guideline for inter-regional or fully co-optimised constraints mainly affecting an interconnector for example is:

'from region ID' 'cause ID(s)' 'to region ID' _ ' outage ID' _ ' unique ID (if necessary)'

Hence, the equation Q:N_ARTW_4 means: Qld to NSW transient stability, Armidale to Tamworth line outage, inter-regional.

When economic dispatch is limited, that is where AEMO cannot dispatch the lowest bid priced generation because of network constraints, a constraint is said to be 'binding'.

Information about constraints feeds into the planning process, as planning bodies will need to assess the costs and benefits of addressing constraints. Where it is economic to do so, constraints can be addressed in by either:

- Augmentations to the transmission infrastructure, called 'network options'.[23]
- Solutions such as demand-side management and network support control ancillary services,[24] which may reduce the strain on transmission infrastructure elements during certain periods, thereby assisting in maintaining operation of this infrastructure within its physical limits. These solutions are termed 'non-network options'.

A.5 The effect of network constraints

Constraints undermine the benefits of interconnection. In particular, congestion in the network can result in certain sources of generation being 'constrained off' from other parts of the network. This may result in the dispatch of higher-priced generation than would not have been the case without the constraint.

In theory, congestion may be eliminated if sufficient money was spent on expanding, or upgrading transmission network infrastructure. However, the cost of doing this may outweigh the costs incurred from the congestion itself. In this sense, congestion occurs not only because of the network's physical limitations, but also because of economic

23 An augmentation refers to work undertaken to enlarge the system (extension) or to increase its capacity to transmit electricity (upgrade).

24 Network control ancillary services can include generation or automatic load reduction to relieve network overload following a contingency.

considerations of net costs and benefits. In other words, some level of congestion is likely to be economically efficient.[25]

Network congestion also impacts on the ability of NEM participants to manage risks associated with inter-regional trade.

Box A.2: Congestion and inter-regional settlement residues[26]

Participants in the NEM who engage in inter-regional trade are exposed to the risk of divergence between regional reference prices in the NEM. This occurs because generators receive the spot price in the region where they operate, while retailers pay the spot price in the region where the electricity purchased is effectively consumed. Because of differences in the regional reference prices, which may be the result of network congestion, there can be a misalignment between the amounts payable and received, causing a financial risk for participants conducting an inter-regional transaction.

NEM participants manage some part of this risk by buying inter-regional settlement residues. Inter-regional settlement residues arise from the transfer of electricity through regulated interconnectors only. These residues are a pool of funds equal to the difference in the regional reference price between two regions in the NEM multiplied by the quantity of electricity flowing over an interconnector between those two regions. As electricity normally flows from lower priced regions to higher priced regions, these funds usually represent a positive amount. These funds are held by AEMO via the NEM settlement process. AEMO then auctions off these residues among interested NEM participants. These auctions provide eligible NEM participants access to the inter-regional settlements residue by enabling them to bid in advance for the right to an uncertain future revenue stream.

As noted above, the methodology for inter-regional settlement residues does not apply in respect of interconnectors which provide market network services. That is, it does not apply to Basslink, which is not a regulated interconnector. For Basslink, inter-regional revenues represent the difference between the value of energy in Victoria and the value of that energy once it has been transferred to Tasmania, or vice versa for flows from Tasmania to Victoria. This difference in value is primarily due to the price difference between the two regions and represents a revenue stream for Basslink. These price differences can also be due to the applications of inter-regional transmission constraints or the dynamic loss factors that apply between the two regions.

Network congestion may, however, give rise to counter-price flows, where electricity flows from a high-priced region to a low-priced region. Under these circumstances, the amount payable by AEMO to the generators in the exporting region (the high-price region) is not covered by amounts received from retailers

25 See AEMC, *Congestion Management Review*, 2008, p51.

26 AEMO, Guide to the settlements residue auction, 22 July 2014, p6.

in the importing region (the low-priced region). As a result, inter-regional settlement residues can be negative. The cost of funding these negative settlement residues is ultimately borne by consumers in the importing region.[27]

27 The proceeds of settlement residue auctions are paid by AEMO to TNSPS, and are subsequently used to reduce the network service fees charged to TNSP customers. Negative settlement residues reduce the proceeds of the auction and hence the amounts payable to TNSPs. TNSPs then recover these expenses through higher network service fees.

B Review of the Queensland–New South Wales interconnector

The Commission does not consider there to be any transmission network constraints on the Queensland–New South Wales interconnector that are not being addressed by the relevant jurisdictional planning bodies in their transmission annual planning reports. There are no network constraints in the main transmission corridors around the interconnector in Queensland and New South Wales that are not being addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a participant under its last resort planning powers.

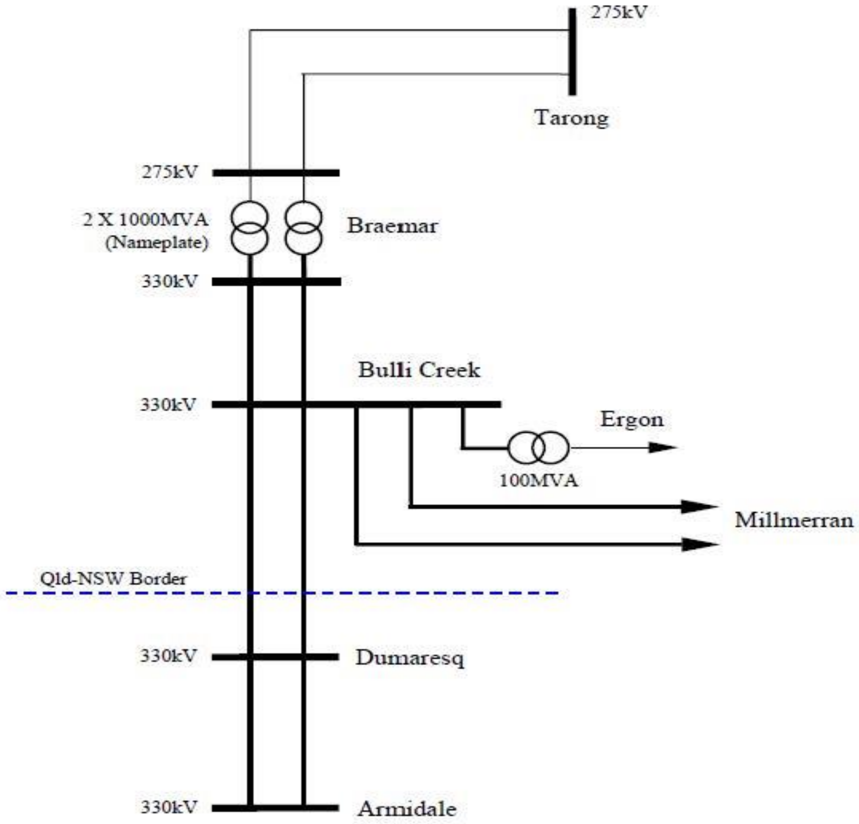
This section outlines the Commission's analysis in support of this conclusion. This analysis includes:

- an overview of the Queensland–New South Wales interconnector;
- a review of the binding constraint equations that most often set the limits on this interconnector from AEMO's 2013 constraint report;
- a review of the emerging transmission network constraints affecting the this interconnector from the 2013 transmission network development plan;
- a review of TransGrid and AEMO's transmission annual planning reports on projects to address limitations to the interconnector and the main transmission corridors; and
- a summary of the projects identified to reduce transmission network constraints.

B.1 Overview of Queensland–New South Wales interconnector

The Queensland–New South Wales interconnector (QNI) connects the South West Queensland zone with the North New South Wales zone. It runs between Bulli Creek in Queensland and Dumaresq in New South Wales. Schematically, QNI can be illustrated as follows.

Figure B.1 Queensland–New South Wales interconnector



Source: Powerlink and TransGrid, Benefits of upgrading the capacity of the QNI, March 2004.

The South West Queensland zone has the highest installed generating capacity in the Queensland region, with 3,450 MW of coal-fired and 2,174 MW of gas-fired generation. There is currently no installed wind generating capacity, but the NTNDP zero carbon price modelling results indicate wind generation in this region from 2015-16.

The Northern New South Wales zone has no major generation sources, so the zone is a net importer and a corridor of power flows between Queensland (both QNI and Terranora) and the rest of New South Wales.

The flow on QNI is normally from Queensland into New South Wales. However, at times of high generation in New South Wales or low generation in Queensland, the flow can reverse and go from New South Wales to Queensland. Due to their close electrical proximity to the New South Wales side, both QNI and Terranora often appear on the left hand side of constraint equations.[28]

28 This means that QNI and Terranora flows can be limited by the same constraint, in which case the NEM dispatch engine (NEMDE) does a trade-off between flows on QNI and Terranora when this constraint binds.

B.2 Findings from the 2013 constraints report

The transfer of electricity from New South Wales to Queensland is mainly limited by the system normal constraint equations for the voltage collapse on loss of the largest Queensland generating unit (Kogan Creek) and the trip of the Liddell to Muswellbrook 330 kV line in New South Wales.[29]

Until November 2013, electrical transfer from New South Wales to Queensland could also be limited by thermal overloads on the Calvale to Wurdong 275 kV, or Calvale to Stanwell 275 kV line in Queensland. However, this set of thermal limit constraint equations has been removed following the construction of the new double circuit 275 kV lines between Calvale and Stanwell.

Transfer from Queensland to New South Wales is normally limited by the transient stability limits for a fault on a Bulli Creek to Dumaresq line or FCAS requirements for outages of lines between Bulli Creek and Liddell. From July 2013, the oscillatory stability limit of this line was increased from 1,078 MW to 1,200 MW.

The top three most binding system normal constraints that affected flows on QNI in both directions for 2013 are outlined in Table B.1.

Table B.1 Binding constraint equations setting the QNI limits in 2013

NSW to Queensland limits			
Equation ID	**Hours binding in 2013**	**Description**	**Market impact (with position in top ten market impacts per region)[a]**
N^^Q_NIL_B1, 2, 3, 4, 5, 6 & N^Q_NIL_B (This constraint was also identified on the Terranora (Directlink) interconnector).	516.8	System normal constraint, to avoid voltage collapse for the loss of the largest Queensland generator. AEMO notes that this voltage collapse limit is split into seven constraint equations to co-optimise with each of the six largest generators in Queensland. Overall N^^Q_NIL_B1 (for trip of Kogan Creek) binds for the most number of intervals.	$898,361 (number one in the top ten constraints with largest market impact in New South Wales)
Q>>NIL_855_871	267.3	System normal constraint, in order to avoid overload on Calvale to Wurdong (871) 275 kV line on trip of Calvale to Stanwell (855) 275 kV line. AEMO notes that this constraint	$2,435,502 (number one in top ten constraints with largest market impact in

29 AEMO, *NEM constraint report 2013*, April 2014, pp26-27.

		equation has been removed following the construction of the new double circuit 275 kV lines between Calvale and Stanwell (8873 and 8874) in late 2013.	Queensland)
N^Q_NIL_A (This constraint was also identified on the Terranora (Directlink) interconnector).	32.7	System normal constraint, avoid voltage collapse on loss of Liddell to Muswellbrook (83) 330 kV line.	$58,192 (number seven in top tem constraints with largest market impact in New South Wales)
Queensland to NSW limits			
Q:N_NIL_BCK2L-G	4.4	System normal constraint, in order to avoid transient instability for a two phase to ground fault on a Bulli Creek to Dumaresq 330 kV line at Bulli Creek For high flows from Queensland to NSW (either this constraint equation or Q:N_NIL_BI_POT or Q:N_NIL_OSC will bind).	$27,148 (number ten in top ten constraints with largest market impact in Queensland)
Q:N_NIL_OSC	2.1	System normal constraint, Queensland to NSW oscillatory stability limit This constraint equation sets the upper limit from Queensland to NSW to 1078 MW. For high flows from Queensland to NSW either this constraint equation or Q:N_NIL_BI_POT or Q:N_NIL_BCK2L-G will bind.	$981 Does not appear in top ten constraints with a market impact in either Queensland or New South Wales.
Q_N_NIL-1078	0.3	System normal constraint, reduce QNI when it is over the 1078 MW limit by 1078 minus the MW over the 1078 MW limit (capped at 1000 MW).	$266 Does not appear in top ten constraints with a market impact in either Queensland or New South Wales.

[a] The market impact is calculated by adding up the marginal values from the marginal constraint cost re-run. To that end, the constraint is relaxed marginally (by 1 MW). This will result in a different dispatch pattern, with different associated costs, compared to the situation under the full constraint. This is done for each dispatch interval during the number of hours a constraint was binding. These values are subsequently added up to provide a total marginal market impact.

Source: AEMO, *NEM constraint report 2013*, April 2014. pp13-15, 20-22, 26-27 and AEMO, NEM constraint report 2013 supplementary data.

B.3 Network constraints affecting the Queensland–New South Wales interconnector

B.3.1 Findings from the 2013 transmission network development plan

The 2013 transmission network development plan did not envisage any constraints on the main transmission network that would require augmentation of QNI in the short term up to 2020-21. The long term planning outlook from 2020 to 2038 also indicated that augmentation of QNI was unlikely to be required.[30]

The 2013 transmission network development plan noted that capacity of the northern New South Wales and south western Queensland main grid network to facilitate power transfer between the two states was identified in annual planning reports as a limitation on the main transmission network. A number of possible network developments are being considered by TransGrid as part of their transmission annual planning requirements. However, many of these projects are contingent on QNI being upgraded.

The 2013 transmission network development plan did not identify any emerging reliability limitations across the main transmission network linking NTNDP zones within the Queensland region and only a potential economic dispatch limitation between central and northern Queensland. This assessment builds on Powerlink's committed projects, both recently completed and planned for the next five years.[31] In addition, the 2013 transmission network development plan identified a network limitation in the southwest Queensland zone for the Columboola to Wandoan and the Columboola to Western Downs lines.[32] Powerlink is committed to construct transmission assets in this zone to increase supply capability to the Surat Basin within the next five years.

B.3.2 Augmentation of the Queensland–New South Wales interconnector

In June 2012, TransGrid and Powerlink issued a project specification consultation report regarding the potential for upgrading of the interconnector capacity across QNI. These two organisations published the project assessment draft report (PADR) in March 2014. Six options were included in the regulatory test for investment (RIT-T) analysis and discussed in the PADR:[33]

- Uprating of the northern New South Wales 330 kV transmission lines;
- Fifty percent series compensation of the interconnecting 330 kV lines between Armidale, Durmaresq and Bulli Creek;

30 AEMO, *National transmission network development plan 2013*, December 2013, p9.

31 Powerlink, Queensland transmission annual planning report 2014, June 2014, p81.

32 AEMO, *National transmission network development plan 2013*, December 2013, p11, APP-1.

33 TransGrid, *New South Wales transmission annual planning report 2014*, June 2014, pp67-68.

- Fifty percent line series compensation and a second Armidale static VAr compensator (SVC);
- Sixty percent series compensation of the interconnecting 330 kV lines between Dumaresq and Bulli Creek;
- A new SVC at Armidale; and
- New SVCs at Dumaresq and Tamworth and switched shunt capacitors at Dumaresq, Armidale and Tamworth substations.

The cost estimates of each option are detailed in the PADR document that may be found on Powerlink and TransGrid's websites. Each of these options was expected to have material inter-network impacts.

The RIT-T assessment identified four important factors, which influence the market benefit of the credible options outlined above. These factors were:

- future gas prices in Queensland;
- the possible retirement of Redbank power station;
- the development of wind farms in northern New South Wales; and
- load growth.

The results of the analysis showed that the ranking of credible options was inconsistent across the scenarios. Furthermore, many credible options had negative net market benefits under a number of scenarios and therefore, ranked below the 'do nothing' option. Therefore, it was the view of Powerlink and TransGrid that there was too much uncertainty around these factors and it was prudent to not recommend a preferred credible option, but to continue to monitor developments in these key input assumptions.

AEMO's report on its assessment of TransGrid's proposed capacity-driven investment also noted that the New South Wales to Queensland transmission capacity upgrade was deferred. AEMO stated that this project was excluded at the substantive proposal stage and that the 2013 transmission network development plan did not identify a need to upgrade the QNI interconnector.[34]

Powerlink and TransGrid are due to publish their project assessment conclusions report regarding upgrading QNI's capacity in late 2014.

34 AEMO, *Independent planning review - New South Wales and Tasmanian transmission networks*, August 2014, p13.

B.3.3 Findings from Powerlink's transmission annual planning report

The transmission network planning and NEM constraint reports have identified network constraints on a number of transmission lines in Queensland. In response, Powerlink committed to the construction of the following projects to remove the identified transmission network constraints:[35]

- Completion of the construction of the new double circuit 275 kV lines between Calvale and Stanwell in November 2013.
- To address identified thermal constraints, Powerlink started construction of a new 275 kV substation at Wandoan South, and construction of a new 275 kV transmission line from Columboola to Wandoan South and from Western Downs to Columboola to be completed by winter 2014
- To address identified thermal constraints and voltage or transient stability constraints, Powerlink completed the construction of the Western Downs to Halys 275 kV transmission line and upgraded the Western Downs and Halys substations.[36] As a result of this augmentation, the transmission capacity is adequate to dispatch the full generation capacity within the Bulli and Surat zones in addition to maximum secure QNI transfer from New South Wales to Queensland.

Powerlink's transmission annual planning report did not identify any further possible network developments that would be required to the next five to ten years relating to improving power transfer capacity over QNI.

B.3.4 Findings from TransGrid's transmission annual planning report

To improve the power transfer capability of the QNI interconnector in both directions, previous transmission network development plans have recommended improvements on the Armidale SVC. In response, TransGrid committed to construction of the following projects to remove the identified transmission network constraints:

- Installation of a power oscillation damper on the Armidale SVC to increase the QNI interconnector's power transfer capability (in the Queensland to New South Wales direction).
- A new 200 MVAr capacitor at the Armidale substation to increase the QNI interconnector's power transfer capability (in the New South Wales to Queensland direction).

35 Powerlink, *Queensland transmission annual planning report*, June 2014, pp46-47, 77-79.

36 Powerlink noted that the final augmentation for this project is the splitting of the 275 kV bus at Braemar substation, and is planned to be completed in August 2014.

TransGrid's 2014 transmission annual planning report noted that the power oscillation damping control was installed on the Armidale SVC in 2013.[37] In relation to the second project, a tender for the refurbishment of one SVC at Armidale was issued by TransGrid in February 2014.[38] TransGrid are planning to complete this project in late 2015.[39]

TransGrid also outlined a number of possible network developments in the northern transmission system that may be required within the next five to ten years. Each of these projects is contingent on QNI being upgraded and new generation being connected in northern New South Wales. The projects included:[40]

- Upgrade of the Tamworth and Armidale 330 kV switchyards - the establishment of QNI and the connection of an SVC at Armidale has changed the utilisation of the substations from serving local load to being critical switching stations and, in the case of Armidale, voltage support for high transfers on QNI.
- Upgrade of the Hunter Valley - Tamworth - Armidale 330 kV system capacity - capacity limitations may arise from increased generation export to/import from Queensland and increased generation developments (gas, solar and wind) in northern New South Wales.
- Voltage control in northern New South Wales - the ability to maintain adequate voltage levels is the most constraining limitation on the New South Wales export capacity to Queensland. In particular, the ability to maintain adequate voltage levels at Tamworth, Armidale and Dumaresq is critical for inter-regional transfer.

B.4 Summary of projects for identified network constraints

In summary, the Commission does not consider there to be any transmission network constraints on QNI, or in the transmission corridors around QNI in Queensland and New South Wales that are not being addressed by the relevant jurisdictional planning bodies in their transmission annual planning reports.

Table B.2 provides a summary of the projects impacting on the QNI interconnector that are noted in the 2013 transmission network development plan and how these limitations are being addressed in Powerlink and TransGrid's transmission annual planning reports.

37 TransGrid, *New South Wales transmission annual planning report*, June 2014, p50.

38 Details of the tender may be found at the NSW eTendering website, https://.tenders.nsw.gov.au/transgrid/ (archived). Last viewed 12 August 2014.

39 TransGrid, *New South Wales transmission annual planning report*, June 2014, p55.

40 ibid, pp91-93.

Table B.2 Summary of project outcomes for the QNI interconnector

Report limitation identified	Project	Purpose	Project status
2013 constraint report	Calvale to Stanwell 275 kV line.	Increase supply capability out of the central west Queensland zone.	Commissioned November 2013
2013 NTNDP (committed project)	Columboola to Wandoan South 275 kV and Wandoan South substation establishment, Columboola to Western Downs 275 kV and Columboola 275 kV substation.	Increase supply capability to Surat Basin north west area.	Progressively from winter 2013 to winter 2014.
2013 NTNDP (committed project)	Western Downs to Halys 275 kV line and Western Downs and Halys substations.	Increase supply capability between Bulli and southwest Queensland zones.	Due to be completed in winter 2014.
2013 NTNDP (committed project)	Armidale SVC power oscillation damper	Increase the QNI interconnector's power transfer capability (in the Queensland to New South Wales direction).	Commissioned 2013.
2013 NTNDP (committed project)	Armidale substation SVC control system replacement	Increase the QNI interconnector's power transfer capability (in the New South Wales to Queensland direction)	Due to be completed in summer 2015.
Current RIT-T assessment	Upgrade of the Queensland - New South Wales interconnector	Increase the capability of QNI to covey electricity between Queensland and New South Wales	Deferred as a result of lower demand growth and no clear net market benefits for any credible network and non-network options analysed.

C Review of Terranora (Directlink) interconnector

> The Commission does not consider there to be any transmission network constraints on Terranora that are not being addressed by the relevant jurisdictional planning bodies in their transmission annual planning reports. There are no network constraints in the main transmission corridors around Terranora in Queensland and New South Wales that are not being addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a participant under its last resort planning powers.

This section outlines the Commission's analysis in support of this conclusion. This analysis includes:

- an overview of the Terranora interconnector;
- a review of the binding constraint equations that most often set the limits on Terranora from AEMO's 2013 constraint report;
- a review of the emerging transmission network constraints affecting the Terranora interconnector from the 2013 transmission network development plan;
- a review of Powerlink and TransGrid's transmission annual planning reports on projects to address constraints on Terranora and the main transmission corridors; and
- a summary of the projects identified to reduce transmission network constraints.

C.1 Overview of Terranora

The Terranora interconnector comprises the two 110 kV lines from Terranora in New South Wales to Mudgeeraba in the South East Queensland zone. The controllable element is a 180 MW DC link between Terranora and Mullumbimby (both in New South Wales), known as Directlink, which consists of three separate DC lines.[41]

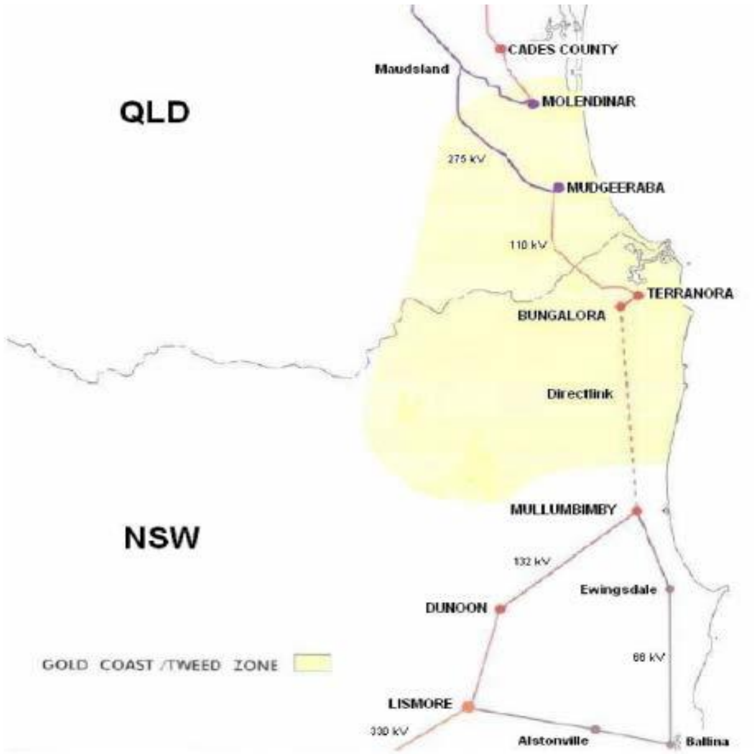
Directlink was commissioned in 2000, forming the first connection between New South Wales and Queensland. The Terranora interconnector is owned by Energy Infrastructure Investments Pty Ltd.

The South East Queensland zone is a major demand centre that includes the Brisbane area, Sunshine Coast and Gold Coast. It currently has 885 MW of installed generation capacity. Under AEMO's zero carbon price scenario modelling, peak gas-fired generation in this zone is not expected until 2027-28 (139 MW), increasing to 1,200 MW

41 Contrary to an AC interconnector, where the voltage and current are at any point sinusoidal, in a DC interconnector, the power is transferred using constant voltage and current.

by 2034-35.[42] With local demand exceeding installed capacity, the South East Queensland zone is a net importer, mainly from the South West Queensland and Central Queensland zones.

Figure C.1 Terranora interconnector



Source: APA Group, Directlink Network management plan, Directlink Joint Venture, May 2013

C.2 Findings from 2013 constraints report

The majority of flows on this interconnector are towards New South Wales, so both the import and export values are negative (unlike the other NEM interconnectors). It is usually constrained by thermal limits in northern New South Wales or the rate of change on Directlink.[43]

The Terranora interconnector normally appears along with the Queensland to New South Wales interconnector (QNI) on the left hand side of the stability constraint equations, so both interconnectors may be constrained at the same time.

The top three most binding system normal constraints in both directions for 2013 that affected flows on Terranora are listed in Table C.1.

42 Under AEMO's carbon price scenario, peak gas-fired generation of 21 MW is predicted to be slightly earlier in 2025-26.

43 AEMO, *NEM constraint report 2013*, April 2014, pp25.

In 2013, most of the time Terranora was restricted due to the outage of all three Directlink cables. All three Directlink cables were out for 158.1 days in 2013 compared with 20.9 days in 2012.[44]

Table C.1 Binding constraint equations setting the Terranora limits in 2013

Equation ID	Hours binding in 2013	Description	Market impact (with position in top ten market impacts per region)[a]
NSW to Queensland limits			
N^^Q_NIL_B1, 2, 3, 4, 5, 6 & N^Q_NIL_B (This constraint is the same as that identified for QNI).	516.8	System normal constraint, to avoid voltage collapse for the loss of the largest Queensland generator. AEMO notes that this voltage collapse limit is split into seven constraint equations to co-optimise with each of the six largest generators in Queensland. Overall N^^Q_NIL_B1 (for trip of Kogan Creek) binds for the most number of intervals.	$898,361 (number one in the top ten constraints with largest market impact in New South Wales)
N>N-NIL_LSDU	122.7	System normal constraint, avoid overloading Lismore to Dunoon line (9U6 or 9U7) 132 kV line on trip of the other Lismore to Dunoon line (9U7 or 9U6) 132 kV line This constraint equation binds for high exports from New South Wales to Queensland.	$325,000 (number three in top ten constraints with largest market impact in New South Wales)
N^Q_NIL_A (This constraint is the same as that identified for QNI).	32.7	System normal constraint, avoid voltage collapse on loss of Liddell to Muswellbrook (83) 330 kV line.	$58,192 (number seven in top tem constraints with largest market impact in New South Wales)
Queensland to NSW limits			
NRM_QLD1_NSW1	28.4	System normal constraint, negative residue management constraint equation for Queensland to New South Wales flows. This constraint equation is part of the automated negative residue	Does not appear in top ten constraints with a market impact in either Queensland or New South Wales.

44 The outage of all three Directlink cables bound for a total of 3,773 hours in 2013 and was the most binding interconnector constraint in the national electricity market. Similarly, instances where two Directlink cables were out equated to 214.9 days, or 196 hours in 2013.

		process which was implemented in July 2012.	
QNTE_ROC	11.9	System normal constraint, rate of change (Queensland to New South Wales) constraint (80 MW/5 Min) for Terranora Interconnector.	$488 Does not appear in top ten constraints with a market impact in either Queensland or New South Wales.
Q>>NIL_MRTX5_MRTX4	0.2	System normal constraint, to avoid overloading Middle Ridge No.4 330/275 kV transformer on trip of Middle Ridge No.5 330/275 kV transformer.	$235 Does not appear in top ten constraints with a market impact in either Queensland or New South Wales.

[a] The market impact is calculated by adding up the marginal values from the marginal constraint cost re-run. To that end, the constraint is relaxed marginally (by 1 MW). This will result in a different dispatch pattern, with different associated costs, compared to the situation under the full constraint. This is done for each dispatch interval during the number of hours a constraint was binding. These values are subsequently added up to provide a total marginal market impact.

Source: AEMO, *NEM constraint report 2013*, April 2014. pp13-15, 20-22, 26-27 and AEMO, NEM constraint report 2013 supplementary data.

C.3 Network constraints affecting Terranora

C.3.1 Findings from the 2013 transmission network development plan

AEMO does not identify the need for increased power transfer capability between Queensland and New South Wales over the Terranora interconnector under its two planning scenarios by 2020-21. Therefore, no augmentations of the Terranora interconnector are listed in the 2013 transmission network development plan.

The transmission network development plan also does not identify any network constraints on the main transmission network in the South East Queensland zone in the transmission corridor leading to Terranora.

C.3.2 Findings from Powerlink's transmission annual planning report

Powerlink affirmed that the short to mid-term outlook in the 2013 transmission network development plan was consistent with the absence of forecast constraints identified across the main transmission network within its annual planning report.[45] As a result, Powerlink has not identified any projects around Terranora, or the transmission corridors leading to Terranora.

45 Powerlink, *Queensland transmission annual planning report 2014, June 2014*, p81.

C.3.3 Findings from TransGrid's transmission annual planning report

The 2013 transmission network development plan identified one long-term transmission limitation within New South Wales that may have an impact on the Terranora interconnector.[46] This network limitation is related to reinforcing the supply of electricity to the far north coast of New South Wales.

In relation to reinforcement of the far north coast, TransGrid made the following observations in its 2014 transmission annual planning report. Supply to the far north coast is limited by the thermal rating constraints on the 132 kV lines on outage of the Armidale to Coffs Harbour 330 kV line.[47]

The onset and severity of this limitation is dependent on the amount of network support available from Queensland via Directlink and the level of flows on QNI. Consequently, as a result of lower load forecasts, TransGrid indicated that overload of the transmission lines servicing the far north coast was not expected to occur within ten years.

C.4 Summary of projects for identified network constraints

Table C.2 provides a summary of the projects impacting on the Terranora interconnector contained in the 2013 transmission network development plan. It also indicates how these constraints are being addressed in Powerlink and TransGrid's transmission annual planning reports.

Table C.2 Summary of project outcomes for Terranora interconnector

Report limitation identified	Project	Purpose	Project status
2013 NTNDP (long-term transmission network limitation up to 2037-38).	Armidale to Coffs Harbour 132 kV line.	Reinforce the supply to the far north coast of New South Wales.	Deferred - the need for this augmentation is not expected to arise within ten years.

46 This identified transmission limitation was not expected to emerge until 2037-38.

47 TransGrid, *New South Wales transmission annual planning report 2014*, June 2014, p46, 95.

D Review of New South Wales–Victoria interconnector

> The Commission does not consider there to be any transmission network constraints on the New South Wales–Victoria interconnector that are not being addressed by the relevant jurisdictional planning bodies in their transmission annual planning reports. There are no network constraints in the main transmission corridors around the interconnector in Victoria and New South Wales that are not being addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a participant under its last resort planning powers.

This section outlines the Commission's analysis in support of this conclusion. This analysis includes:

- an overview of the New South Wales–Victoria interconnector;
- a review of the binding constraint equations that most often set the limits on this interconnector from AEMO's 2013 constraint report;
- a review of the emerging transmission network constraints affecting the this interconnector from the 2013 transmission network development plan;
- a review of TransGrid and AEMO's transmission annual planning reports on projects to address constraints on the interconnector and the main transmission corridors; and
- a summary of the projects identified to reduce transmission network constraints.

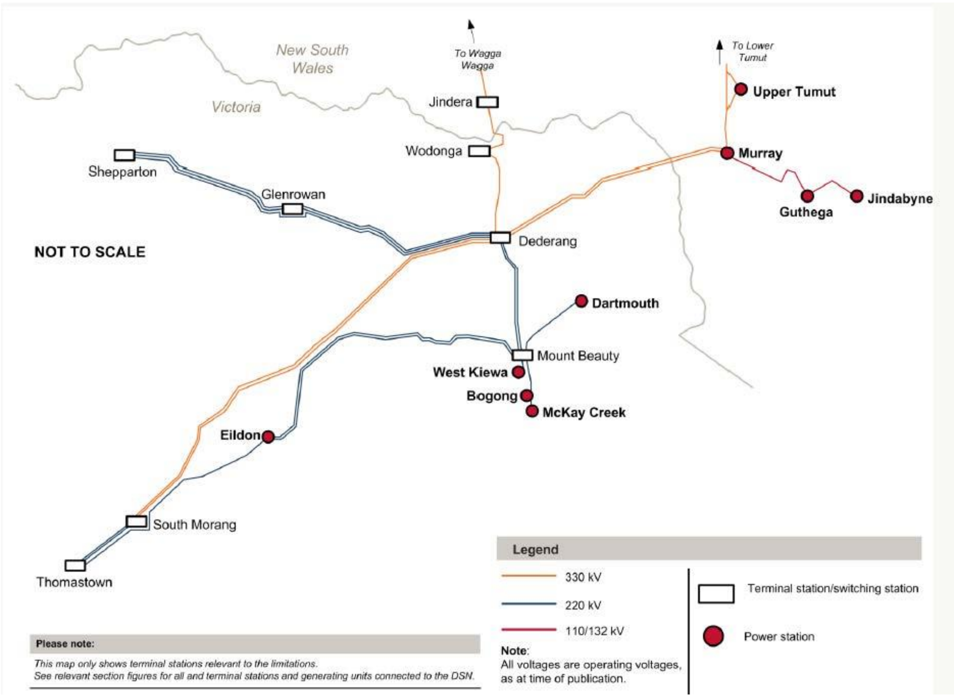
D.1 Overview of the Victoria–New South Wales interconnector

New South Wales and Victoria are interconnected via the Victoria to New South Wales interconnector (VIC1-NSW1). It comprises the 330 kV lines between Murray and Upper Tumut, Murray and Lower Tumut, Murray and Denderang and Jindera and Woodonga. The interconnector links the South West New South Wales zone with the Northern Victoria zone.

Both zones contain a large amount of hydroelectric generation, which is exported into New South Wales and into Victoria. As such, it is part of the 'Northern corridor' running between Murray (New South Wales) and South Morang (Victoria).

The 2013 transmission network development plan notes that the South West New South Wales zone currently has no wind generation, however, under both the zero carbon price and carbon price scenarios, the amount of installed wind generation is expected to increase from 2015-16 and 2016-17 respectively. Aside from hydroelectricity, no other energy source emerges in Northern Victoria in the transmission planning report.[48]

Figure D.1 Victoria–New South Wales interconnector



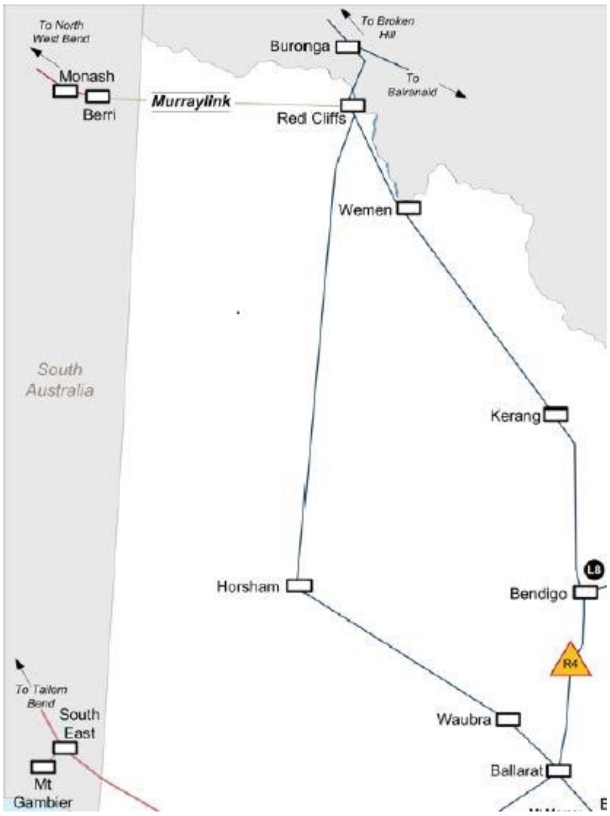
Source: AEMO, Victorian annual planning report, 2014, p33.

In addition, the 220 kV line between Buronga and Red Cliffs connects Victoria's north west (part of the Country Victoria zone) to the South West New South Wales zone. The network delivers supply to load centres in Country Victoria (such as Bendigo and Ballarat), but also transfer power to South Australia (via the Murraylink interconnector) from New South Wales.

In the 2013 transmission network development plan modelling, a significant amount of wind generation is expected to be established in the Country Victoria zone.

48 AEMO, *National transmission network development plan 2013*, December 2013, pp6-8.

Figure D.2 Victoria–New South Wales interconnector at Red Cliff



Source: AEMO, Victorian annual planning report, 2014, p31.

D.2 Findings from 2013 constraints report

The Victoria–New South Wales interconnector may bind in either direction due to high demand in New South Wales or Victoria. Transfer from Victoria to New South Wales is mainly limited by the thermal overload limits on the South Morang F2 transformer, the South Morang to Denderang 330 kV line, the Ballarat to Bendigo 220 kV line, or the Ballarat to Moorabool No. 1 220 kV line.[49]

The transient stability limit for a fault and trip of a Hazelwood to South Morang line may also set the limits; however, these constraints have rarely bound since the middle of 2012.

Transfer from New South Wales to Victoria is mainly limited by voltage collapse for loss of the largest Victorian generator, voltage collapse for the loss of a Murray to Denderang 330 kV line, or the thermal overload limits on the Murray to Denderang 330 kV lines.

The top three most binding system normal constraints in both directions for 2013 that affected flows on the Victoria - New South Wales interconnector is listed in Table D.1.

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49 AEMO, *NEM constraint report 2013*, April 2014, pp28-29.

Table D.1 Binding constraint equations setting the Victoria–New South Wales interconnector limits in 2013

Victoria to NSW limits			
Equation ID	**Hours binding in 2013**	**Description**	**Market impact (with position in top ten market impacts per region)[a]**
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P (This constraint was also identified on the Murraylink, Heywood and Basslink interconnectors).	188.0	System normal constraint, avoid overloading the South Morang 500/330 kV (F2) transformer for no contingencies, for radial/parallel modes and Yallourn W1 on the 500 or 220 kV. AEMO notes that these constraint equations maintain flow on the South Morang F2 transformer below its continuous rating. AEMO considers that the combination of these three constraint equations will bind for a similar amount in 2014.	$9,407 Does not appear in top ten constraints with a market impact in either Victoria or New South Wales.
V>>SML_NIL_7A	71.5	System normal constraint, avoid overloading Ballarat North to Buangor 66 kV line on trip of the Ballarat to Waubra to Horsham 220 kV line.	$34,306 Does not appear in top ten constraints with a market impact in either Victoria or New South Wales.
V>>V_NIL1A_R	30.1	System normal constraint, avoid overloading a South Morang to Dederang 330 kV line for trip of the parallel line.	$1,104 Does not appear in top ten constraints with a market impact in either Victoria or New South Wales.
NSW to Victoria limits			
N^^V_NIL_1	102.1	System normal constraint, avoid voltage collapse for loss of the largest Victorian generating unit.	$28,564 Does not appear in top ten constraints with a market impact in either Queensland or New South Wales.
N^^V_NIL_2	21.0	System normal constraint, avoid voltage collapse for loss of a Dederang to Murray 330 kV line.	$45,018 (number ten in top ten constraints with largest market impact in New South

			Wales).
V>>V_NIL_1B	13.5	System normal constraint, to avoid overloading Dederang to Murray No.2 330 kV line for trip of the Dederang to Murray No.1 330 kV line.	$40,047 Does not appear in top ten constraints with a market impact in either Queensland or New South Wales.

[a] The market impact is calculated by adding up the marginal values from the marginal constraint cost re-run. To that end, the constraint is relaxed marginally (by 1 MW). This will result in a different dispatch pattern, with different associated costs, compared to the situation under the full constraint. This is done for each dispatch interval during the number of hours a constraint was binding. These values are subsequently added up to provide a total marginal market impact.

Source: AEMO, *NEM constraint report 2013*, April 2014. pp13-15, 20-22, 26-27 and AEMO, NEM constraint report 2013 supplementary data.

D.3 Network constraints on the New South Wales–Victoria interconnector

D.3.1 Findings from the 2013 transmission network development plan

AEMO has not identified the need for increased power transfer capability between Victoria and New South Wales over the Victoria–New South Wales interconnector under its two planning scenarios over the next 25 years. Additional Victoria–New South Wales interconnector capacity did not appear in the least cost generation and transmission expansion modelling study, and as such no requirement for augmentation was noted.

The transmission network development plan does not identify any network constraints in the New South Wales main transmission corridor that would have implications for power transfer over the Victoria–New South Wales interconnector. However, one committed project is identified relating to the construction of six new reactors at the Yass and Murray substations. The transmission network development plan also identified the potential for economic dispatch constraints over the long-term that may affect the transfer of power from the Snowy area to Canberra and Sydney.[50]

In Victoria, the transmission network development plan identifies two areas in Country Victoria that may develop potential economic dispatch constraints by 2037-38. These constraints are located on the Red Cliffs–Wemen–Kerang 220 kV line and the Ballarat–Waubra–Horsham 220 kV line. These two constraints are expected to have implications for the supply of electricity over the New South Wales–Victoria interconnector at Red Cliff. The Ballarat–Waubra–Horsham constraint can also lead to binding of the Victoria–New South Wales interconnector for power transfers into New South Wales.[51]

50 AEMO, *National transmission network development plan 2013*, December 2013, p.20.

51 ibid.

D.3.2 Findings from AEMO's Victorian transmission annual planning report

The 2014 Victorian transmission annual planning report does not identify any further network constraints through the Northern Corridor since publication of the 2013 planning report that would affect power transfer across the Victoria - New South Wales interconnector.[52]

Priority transmission network constraints

The 2014 planning report identified a priority limitation in the Country Victoria zone, Denderang–Shepparton line, that may have implications for the import of electricity from New South Wales. This limitation arises as a result of completion of thermal network upgrades to remove constraints on the Moorabool–Ballarat and Ballarat–Bendigo 220 kV lines in Western Victoria causing congestion under peak loading conditions on this line. The loading on the Denderang–Shepparton line can be reduced by re-dispatching generation and limiting import from New South Wales, but this may increase Victorian market prices due to the need to dispatch higher cost plants in Victoria, Tasmania and South Australia. To alleviate this limitation a number of network options are being considered by AEMO in consultation with SP AusNet.[53]

A further priority limitation in Country Victoria relates to an outage of either the Horsham–Red Cliffs or Ballarat–Horsham 220 kV lines. Preliminary analysis by AEMO indicates that the Ararat–Challicum Hills 66 kV line section may exceed its short-term thermal rating for outages on the Horsham–Red Cliffs or Ballarat–Horsham 220 kV lines. The level of overload is dependent on various factors including generation levels, demand and interconnector flows. AEMO intend to further analyse the network and non-network options for alleviation of this network limitation in 2014-15.[54]

Constraints being monitored in the Northern Corridor

In addition to the above priority constraints, AEMO is also monitoring a number of network constraints in Victoria that may need to be addressed as a result of greater imports from, and/or exports to, New South Wales. These projects include:[55]

- Installation of a third 330 kV line between Murray and Denderang, or a second 330 kV line from Denderang to Jindera;
- Up-rating the two Denderang–South Morang 330 kV lines and installation of a third (single-circuit) 330 kV line between Denderang and South Morang;
- Installation of a wind monitoring scheme or up-rating the conductor temperature of both 220 kV circuits between Denderang and Mount Beauty;

52 AEMO, *Victorian transmission annual planning report 2014*, June 2014, p12.

53 AEMO, Victorian transmission annual planning report 2014, June 2014, p61.

54 ibid, p62.

55 ibid, pp52-53 and 59.

- Installation of a wind monitoring scheme or up-rating the Eildon–Thomastown 220 kV line, including terminations to 75 °C operation;
- Installing a fourth 330/220 kV transformer at Denderang;
- Installation of additional capacitor banks and/or controlled series compensation at Denderang and Wodonga terminal stations; and
- Installation of a second 500/330 kV transformer at South Morang F2, or a new 500/220 kV transformer at South Morang F2 and connection of the Thomastown–Rowville 220 kV line at South Morang.

Constraints being monitored in Regional Victoria

AEMO is also monitoring a number of transmission constraints in Regional Victoria that may arise as a result of increased demand in Regional Victoria and/or increased import from New South Wales. These projects include augmentation to the:[56]

- Bendigo–Fosterville–Shepparton 220 kV line;
- Denderang–Shepparton 220 kV line – which may include replacement of the existing single circuit with a double circuit along a part of, or the whole line; and
- Kerang–Wemen–Red Cliffs 220 kV line – in the event that significant new wind generation is connected to this line, AEMO is considering replacing the existing single circuit with a double circuit 220 kV line.

D.3.3 Findings from TransGrid's New South Wales transmission annual planning report

In relation to New South Wales interconnection, TransGrid provided the following commentary in its 2014 transmission annual planning report.[57] TransGrid has worked with AEMO previously on options for improving interconnection between the two states. These options were aimed at improving both the import and export capability of the transmission system. Currently, these developments are not expected to be cost effective within ten years. However, those options that have been considered include:

- upgrading Victorian lines and transformers, SVC installation and a braking resistor to improve the Victorian export capability;
- reactive support in the Jindera area, line series compensation of the Lower Tumut–Wagga–Jindera system or other power flow control devices to improve the Victorian import capability; and
- major 330 kV line development to provide a significant increase in the Victorian import capability.

56 ibid, p63.

57 TransGrid, *New South Wales transmission annual planning report 2014*, June 2014, p98.

Committed main transmission network projects

The 2012 transmission network development identified a gap in the network support and control of ancillary services capability in New South Wales. Through a tender process, TransGrid was selected to supply these services to AEMO in New South Wales.[58]

To meet the shortfall in voltage control ancillary services identified, TransGrid installed three 181 MVAr 362 kV shunt reactors at both the Murray switching station and Yass 330/132 kV substation. TransGrid's transmission annual planning report noted that the installation of these six reactors was completed May 2014.

Forecast potential economic dispatch constraints

TransGrid have indicated that there may be nett market benefits if parts of the network between Snowy and Sydney were to be up-rated. TransGrid have investigated a number of options on the lines between the Victoria–New South Wales interconnector and Sydney. Those projects relevant to the removal of network constraints on the interconnector include:[59]

1. Increased power transfer from the Upper and Lower Tumut switching stations on the Yass and Canberra 330 kV lines through up-rating of these lines. The need for increased power transfer could arise from:

   — increased Snowy generation;

   — increased import from South Australia and Victoria at times of high demand in New South Wales and Queensland;

   — load growth in New South Wales and Queensland; and

   — decommissioning or reduction of coal-fired generation in New South Wales.

   From preliminary market modelling, TransGrid have indicated that the Snowy–Canberra capacity upgrade may be cost effective from after 2015.

2. Increased power transfer on Canberra–Yass–Bannaby and Canberra–Yass–Marulan 330 kV lines. System studies have identified that the existing arrangements on these lines could be constrained under certain operating conditions if:

   — The Snowy–Canberra network (outlined above) is upgraded and generation from Victoria and Snowy is transferred to New South Wales to the maximum capacity allowed up the upgrade; and

58 TransGrid, *New South Wales transmission annual planning report 2014*, June 2014, p51.

59 ibid, p84.

— The present and future wind farms connected in the Southern New South Wales zone operate at or near their maximum capacities

TransGrid noted that this option is contingent on upgrading the Snowy–Canberra lines and the connection of more wind generation in this area of the network.

D.4 Summary of projects for identified network constraints

In summary, the Commission does not consider there to be any transmission network constraints on the Victoria–New South Wales interconnector, or in the transmission corridors around this interconnector in Victoria and New South Wales that are not being addressed by the relevant jurisdictional planning bodies in their transmission annual planning reports.

Table D.2 provides a summary of the projects impacting on the Victoria–New South Wales interconnector that are noted in the 2013 transmission network development plan and how these constraints are being addressed in AEMO and TransGrid's transmission annual planning report.

Table D.2 Summary of project outcomes for Victoria–New South Wales interconnector

Report limitation identified	Project	Purpose	Project status
2013 NTNDP (Committed project).	New reactors: 3 x 150 MVAr at Yass substation and 3 x 150 MVAr at Murray substation.	Provide network support and control ancillary services to AEMO to maintain power system security and reliability , or to increase the power transfer capability of the transmission network.	Commissioned May 2014.

E Review of Heywood interconnector

> As the Heywood interconnector is currently being upgraded by ElectraNet and AEMO, the Commission does not consider there to be any transmission network constraints on this interconnector that are not being addressed by the relevant jurisdictional planning bodies in their transmission annual planning reports. There are not any network constraints in the main transmission corridors around the interconnector in Victoria and New South Wales that are not being addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a participant under its last resort planning powers.

This section outlines the Commission's analysis in support of this conclusion. This analysis includes:

- an overview of the Heywood interconnector;
- a review of the binding constraint equations that most often set the limits on this interconnector from AEMO's 2013 constraint report;
- a review of the emerging transmission network constraints affecting this interconnector from the 2013 transmission network development plan;
- a review of ElectraNet and AEMO's transmission annual planning reports on projects to address constraints on the interconnector and the main transmission corridors; and
- a summary of the projects identified to reduce transmission network constraints.

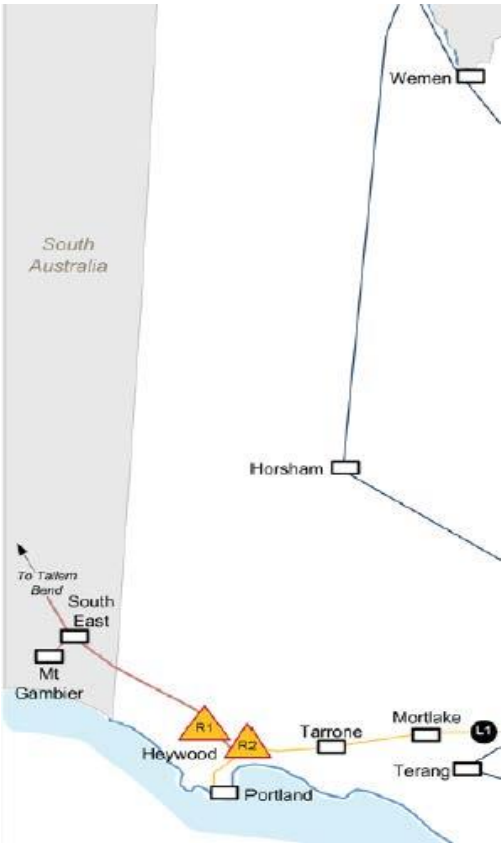
E.1 Overview of the Heywood interconnector

The Heywood interconnector is an AC connection between Heywood in Victoria, part of the South West corridor from Portland to Melbourne, and the South East substation in South Australia (part of this state's South East zone). It was constructed in 1988 and features a 500/275 kV transformer at Heywood and operates at 275 kV into South Australia.

The wider Country Victoria zone includes load centres such as Geelong and Ballarat, and it links to the Melbourne and Northern Victoria zones.

The transmission network in the South East South Australia zone supplies loads within this zone and transfers power towards Victoria. There is currently limited installed generation within the zone, mainly from wind energy. In the transmission network development plan, wind and biomass generation capacity increases over the outlook period.

Figure E.1 Heywood interconnector



Source: AEMO, Victorian annual planning report 2014, June 2014, p31.

Typically, most of the flows on the Heywood interconnector were from Victoria to South Australia. However, with the increasing number of wind farms in South Australia, the flow is now often from South Australia to Victoria. To alleviate constraints in this direction, in March 2010 the limit from South Australia to Victoria on the Heywood interconnector was increased from 300 to 460 MW and the combined Heywood and Murraylink limit was increased to 580 MW in January 2011.

In practice, power transfer capability between Victoria and South Australia via the Heywood interconnector is restricted by:

- the 460 MV limitation of transformer capacity at Heywood;
- voltage collapse constraints on the South Australia network following a South Australian generator trip; and
- thermal limitation on the underlying 132 kV transmission system in the South East Australia zone.

To further increase the capacity of the Heywood interconnector such that generation may be more easily transferred to South Australia during peak demand conditions and a greater amount of wind generation may be exported via Victoria to the national electricity market, ElectraNet and AEMO conducted a regulatory test for investment. The results of this assessment are outlined in section E.3.2.

E.2 Findings from 2013 constraints report

Along with other interconnectors to Victoria (Victoria–New South Wales, Basslink, and Murraylink), the Heywood interconnector appears in many of the Victorian constraint equations. This can lead to situations where many of these interconnectors can be limited due to the same network limitation.

As a result of the capacity increases, the voltage collapse limit for loss of South Australia's largest generator is no longer the majority interconnector limit setter for transfer from Victoria to South Australia – 1,026 hours in 2011, 220 in 2012 and down to 209 in 2013.

Flows are now most often restricted by thermal overloads on the Snuggery to Keith 132 kV line and the Heywood 500/275 kV transformers.

South Australia to Victoria transfers are mainly restricted by the thermal overload limits on the South East substation 275/132 kV transformers and the South Morang F2 transformer.

The top three most binding system normal constraints in both directions for 2013 that affected flows on the Heywood interconnector are listed in Table E.1.

Table E.1 Binding constraint equations setting the Heywood interconnector limits in 2013

Victoria to South Australia limits			
Equation ID	**Hours binding in 2013**	**Description**	**Market impact (with position in top ten market impacts per region)[a]**
V>>S_NIL_SETB_SGKH	648.6	System normal constraint, avoid overloading Snuggery to Keith 132 kV line on trip of a South East to Tailem Bend 275 kV line. AEMO notes that this will bind for high import into South Australia with high levels of generation from the wind farms and gas turbines in the south east. With a revised rating provided in December 2013 AEMO expects this constraint equation to bind less in 2014.	$533,537 This constraint appears as number two in the top ten constraints with largest market impact in South Australia.
V>S_460	300.3	System normal constraint, Victoria to South Australia on Heywood upper transfer limit of 460 MW. AEMO notes that with the	$191,827 This constraint appears as number seven in the top ten constraints with

		update to the V^^S_NIL_MAXG_xxx constraint equations in January 2013 this constraint equation is now more likely to bind. AEMO expects this will bind at similar levels until the Heywood upgrade in mid-2016.	largest market impact in Victoria.
V>S_NIL_HYTX_HYTX	249.7	System normal constraint, avoid overloading the remaining Heywood 275/500 kV transformer on trip of one Heywood 275/500 kV transformer. AEMO notes that with the update to the V^^S_NIL_MAXG_xxx constraint equations in January 2013 this constraint equation is now more likely to bind. AEMO expects this will bind at similar levels until the Heywood upgrade in mid-2016.	$804,155 This constraint appears as number one in the top ten constraints with largest market impact in Victoria.
South Australia to Victoria limits			
S>>V_NIL_SETX_SETX	445.7	System normal constraint, avoid overloading a South East 275/132 kV transformer on trip of the remaining South East 275/132 kV transformer. AEMO notes that this constraint equation binds when there is export from South Australia to Victoria and high generation from the wind farms and gas turbines in the south east of South Australia.	$283,673 This constraint appears as number four in the top ten constraints with largest market impact in South Australia.
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P (This constraint was also identified on the Victoria–New South Wales, Murraylink and Basslink interconnectors).	183.0	System normal constraint, avoid overloading the South Morang 500/330 kV (F2) transformer for no contingencies, for radial/parallel modes and Yallourn W1 on the 500 or 220 kV.	$9,407 Does not appear in top ten constraints with a market impact in either Victoria or South Australia.
S>>V_NIL_NOTI_x & S>NIL_NOTI_x	68.8	System normal constraint, Torrens Island 66kV CB6W2, CB6W3 & CB6E6 open; avoid overload of Torrens Island - New Osborne 66kV No.4 line on trip of Torrens Island - New Osborne 66kV No.3 line.	$192,236 This constraint appears as number five in the top ten constraints with largest market impact in South

		AEMO notes that these constraint equations manage the flows on the Torrens Island to New Osborne No.3 and No.4 66 kV lines for different configurations of the Torrens Island 66 kV bus. The different constraint equations were created in early 2013 following the splitting of the Torrens Island 66 kV bus. Their binding results have been combined. These constraint equations generally bind for high output from the Quarantine gas turbines.	Australia.

[a] The market impact is calculated by adding up the marginal values from the marginal constraint cost re-run. To that end, the constraint is relaxed marginally (by 1 MW). This will result in a different dispatch pattern, with different associated costs, compared to the situation under the full constraint. This is done for each dispatch interval during the number of hours a constraint was binding. These values are subsequently added up to provide a total marginal market impact.

Source: AEMO, *NEM constraint report 2013*, April 2014. pp13-15, 20-22, 26-27 and AEMO, NEM constraint report 2013 supplementary data.

E.3 Network constraints on the Heywood interconnector

E.3.1 Augmentation of the Heywood interconnector

In February 2011, ElectraNet and AEMO collectively published the South Australian Interconnector Feasibility Study, the purpose of which, was to assess the economic benefits possible from increasing the transfer capacity between South Australia and the rest of the national electricity market.

The study found that expanding the transfer capacity of the Heywood interconnector would relieve the current constraints, and would increase both import and export capability. This would result in an increase in several classes of market benefit. in particular:

- reduced total dispatch costs, including fuel costs, by enabling low cost generation to displace higher cost generation;
- reduced generation investment costs, resulting from both the deferral of generation investment, in both South Australia and the rest of the national electricity market, and reduced capital costs associated with meeting the large renewable energy target due to higher wind generation capacity factors in South Australia compared to other locations; and
- potential competition benefits through increased ability of generators to compete across the interconnector.

A number of options were considered for upgrading the interconnector capability. AEMO and ElectraNet published the project assessment draft report, part of the regulatory test for investment for transmission process in January 2013. Subsequently, ElectraNet submitted a request to the AER in April 2013 for a determination on whether the preferred options satisfy the regulatory test.

The AER found that the option identified by ElectraNet and AEMO in their report provides the maximum economic benefits, and satisfies the requirements of the regulatory test. The upgrade would increase the capability of the network to transfer electricity between the two regions. The AER noted that a stronger interconnector at Heywood would increase energy flows between South Australia and Victoria, especially in peak times when prices can be volatile. The interconnector upgrade would introduce further competition for generators, and would enable consumers in both regions to access cheaper sources of energy.

ElectraNet applied to the AER for an allowance for the cost of the Heywood interconnector upgrade to be included in charges during the 2013-18 regulatory control period. The AER made its contingent project decision in March 2014 and approved the incremental revenue for the project requested by ElectraNet.

The scope of the final project to upgrade the Heywood interconnector includes:

- A third 500/275 kV transformer at the Heywood 500 kV transmission terminal station, to be delivered by AEMO and SP AusNet.
- Series compensation of the two South East to Tailem Bend 275 kV lines.
- Reconfiguration of substation assets and the existing 132 kV transmission system to allow increased utilisation of transmission line thermal ratings along the 275 kV interconnector.
- South East 275/132 kV transformer control scheme, subject to the voluntary participation of the relevant generator(s).

In developing the network augmentation components, due consideration has been given to alleviating most of the existing intra-regional network limitation in south-east South Australia. The upgrade is expected to have a material impact on inter-regional transfer as it will increase interconnector capability by about 40 percent in both directions. The net market benefits are estimated at more than $190 million, in present value terms, over the life of the project with positive net benefits commencing from the first year of operation.

E.3.2 Findings from the 2013 transmission network development plan

The 2013 transmission network development plan noted the Heywood interconnector upgrade, to be completed in 2016, as a committed project.

Within South Australia, the transmission network development plan also identified four network constraints on the ElectraNet network as potential market benefit constraints. These constraints are expected to occur in both the short to medium outlook, by 2021, and the long-term outlook from 202-21 to 2037-38. Of these constraints, one relates to the South Australian transmission corridor leading up to the Heywood interconnector, that of the Upper South East, Tailem Bend–Tungkillo, transmission corridor.

Within the Victorian transmission corridor leading up to the Heywood interconnector, the transmission network development plan identified one network limitation. This limitation was expected to occur in the long-term outlook from 2020-21 to 2037-38. The limitation arises during periods of high wind generation and thermal generation in the Victorian south west corridor and high imports from South Australia, and relates to inadequate South-west Melbourne 500 kV thermal capacity.

E.3.3 Findings from the AEMO's Victorian transmission annual planning report

AEMO's 2014 transmission planning report outlined its response to the identified limitation on the 500 kV South-west transmission corridor. AEMO noted that the need to act on this limitation would be triggered in the event that there is significant new wind and/or gas-fired generation, over 2,500 MW in addition to the existing generation from Mortlake, connected to the transmission network. The possible network solution being considered by AEMO at this time is a new Moorabool–Mortlake/Tarrone–Heywood 500 kV transmission line with an estimated cost of $431.8 million. In the event that this network limitation eventuates, AEMO would undertake a regulatory test for investment and evaluate the most appropriate network and non-network options.

E.3.4 Findings from ElectraNet's South Australian transmission annual planning report

ElectraNet noted in its 2014 transmission planning report that it has investigated transmission constraints that are likely to occur after the Heywood interconnector has been upgraded in 2016. Planning studies have indicated that congestions on the interconnector will tend to occur north of Tailem Bend, between Tailem Bend and Tungkillo on the 275 kV network between Tailem Bend and Mobilong on the 132 kV network.

As a result of higher gas prices in South Australia, ElectraNet considered that there will be an increase in flows across the interconnector from Victoria with increase imports of cheaper coal-fired generation.

Therefore the market benefits due to constraints appearing in the upper South East transmission corridor will accumulate under high import conditions and may warrant an increase in the thermal capability of the network north of Tailem Bend in the near term. ElectraNet is considering a number of options to increase the thermal capacity through this corridor, including line up-rating and/or stringing a new circuit.

ElectraNet anticipates that once congestion across the upper South East transmission corridor is addressed that constraints are likely to appear on the Tailem Bend to South

East and South East to Heywood 275 kV line sections. Real time rating[60] of these line sections is likely to address further constraints that may appear in both directions, but particularly in the export direction from South Australia due to the coincidentally favourable environmental conditions for both line ratings and wind based generation.

However, line ratings alone are unlikely to be of help during adverse weather conditions, particularly hot summers. To remove constraints under these conditions, line up-rating beyond the current line design is also being investigated. In this context, it is also important to note that the majority of the South East to Heywood 275 kV line sections are in Victoria and are owned by SP AusNet. Any augmentation to this transmission line will require close interaction with SP AusNet.[61]

ElectraNet intends to undertake further work in the second half of 2014 to confirm the potential benefits of upgrading the Upper South East Transmission Corridor prior to the commencement of any formal regulatory test for investment.

E.4 Summary of projects for identified network constraints

In summary, the Commission does not consider there to be any transmission network constraints on the Heywood interconnector, or in the transmission corridors around this interconnector in Victoria and South Australia that are not being addressed by the relevant jurisdictional planning bodies in their transmission annual planning reports.

Table E.2 provides a summary of the projects impacting on the Heywood interconnector that are noted in the 2013 transmission network development plan and how these constraints are being addressed in AEMO and ElectraNet's transmission annual planning report.

Table E.2 Summary of project outcomes for the Heywood interconnector

Report limitation identified	Project	Purpose	Project status
2013 NTNDP (Committed project).	Heywood interconnector upgrade.	Incremental augmentation of the Victoria–South Australia interconnector. Scope of work in Victoria: • third 370 MVA 500/275 kV transformer and bus tie at Heywood. Scope of work in South Australia:	Completion anticipated in 2016.

60 Real time thermal rating, relates to a system developed for overhead transmission lines that uses actual meteorological data and real-time conductor temperatures and line loadings. This provides much higher capacity allowances than that derived from conventional methods.

61 On 4 August 2014, SP AusNet was renamed as AusNet Services.

Report limitation identified	Project	Purpose	Project status
		• 275 kV series compensation; • re-configuration and decommissioning of the 132 kV network; and • control scheme to enable increased wind generation in south-east South Australia when both South East 275/132 transformers are in service.	
2013 NTNDP (Potential economic dispatch limitation).	Tailem Bend–Tungkillo 275 kV line.	Reduce congestion on this line due to new generation east of Adelaide or high import from Victoria.	Further work from second half of 2014. Regulatory test for transmission to be undertaken if there are net benefits.
2013 NTNDP (Potential economic dispatch limitation)	Transmission constraints on the 500 kV network along the western corridor.	Reduce transmission network congestion on this line due to high wind generation penetration in the Melbourne area, and/or high imports from South Australia over the Heywood interconnector combined with moderate levels of gas-fired generation at Mortlake.	AEMO are currently monitoring this network limitation. Regulatory test for transmission to be undertaken if there are net benefits.

F Review of Murraylink interconnector

The Commission does not consider there to be any transmission network constraints on the Murraylink interconnector that are not being addressed by the relevant jurisdictional planning bodies in their transmission annual planning reports. There are no network constraints in the main transmission corridors around the interconnector in Victoria and South Australia that are not being addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a participant under its last resort planning powers.

This section outlines the Commission's analysis in support of this conclusion. This analysis includes:

- an overview of the Murraylink interconnector;
- a review of the binding constraint equations that most often set the limits on this interconnector from AEMO's 2013 constraint report;
- a review of the emerging transmission network constraints affecting this interconnector from the 2013 transmission network development plan;
- a review of ElectraNet and AEMO's transmission annual planning reports on projects to address constraints on the interconnector and the main transmission corridors; and
- a summary of the projects identified to reduce transmission network constraints.

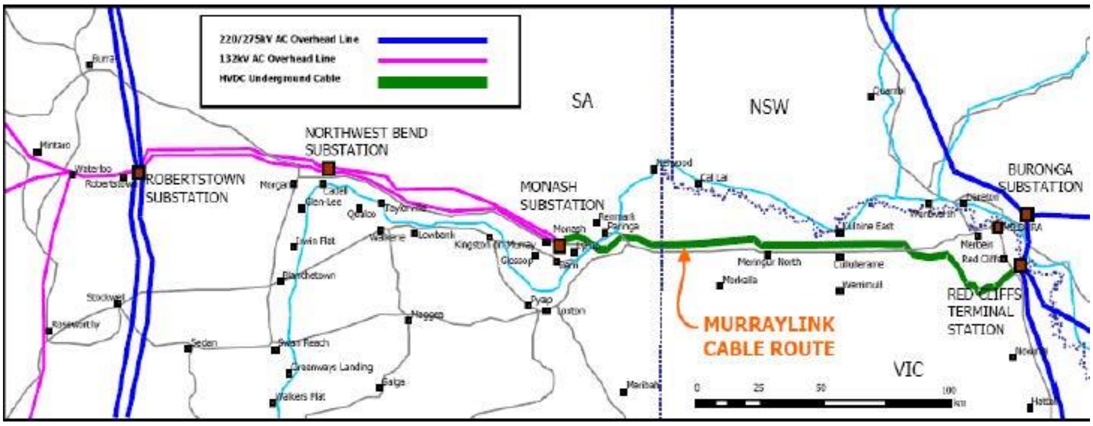
F.1 Overview of Murraylink interconnector

Murraylink is a 220 MW DC link between Red Cliffs in Victoria and the Monash substation near Berri in South Australia, which was commissioned in 2002. The Murraylink interconnector is owned by Energy Infrastructure Investments Pty Ltd. It connects the County Victoria zone with the North South Australia zone.

The Country Victoria zone currently has 312 MW of installed wind generation capacity; however, this amount is expected in increase significantly over the outlook period.

The North South Australia zone, which covers the Mid-North, Upper North, Eyre Peninsular and Riverland areas, accounts for approximately 20 percent of the region's total demand. The zone is connected to the Adelaide zone via four 275 kV circuits and one 132 kV circuit. The zone currently has 844 MW of installed wind generation capacity and 318 MW of gas-fired generation. The 530 MW of coal-fired generation currently installed is forecast to be retired under AEMO's modelling by 2030-31. Solar power is expected to increase under AEMO's modelling from 0 MW currently to 400 MW from 2019-20.

Figure F.1 Murraylink interconnector



Source: Australian pipeline trust, Acquisition of Murraylink Transmission Company, 30 March 2006.

F.2 Findings from 2013 constraints report

Many of the thermal issues closer to Murraylink are handled by the South Australian or Victorian Murraylink runback schemes. Along with other interconnectors to Victoria (Victoria–New South Wales, Heywood and Basslink), Murraylink appears in many of the Victorian constraint equations. This can lead to situations where many or all of these interconnectors can be limited due to the same network limitation.

Transfers from Victoria to South Australia on Murraylink are mainly limited by thermal overloads on the South Morang F2 transformer overload. South Morang–Denderang 330 kV line, Ballarat–Bendigo 220 kV line or voltage collapse limit for loss of the Darlington Point–Buronga (x5) 220 kV line for an outage of the NSW Murraylink runback scheme.

Murraylink transfers from South Australia to Victoria are limited by thermal overloads on the Robertstown–Monash 132 kV lines, the Denderang–Murray 330 kV lines, or the Robertstown transformers.

The top three most binding system normal constraints on the Murraylink in each direction are outlined in Table F.1.

Table F.1 Binding constraint equations setting the Murraylink limits in 2013

Victoria to South Australia limits			
Equation ID	**Hours binding in 2013**	**Description**	**Market impact (with position in top ten market impacts per region)[a]**
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P	188.0	System normal constraint, avoid overloading the South Morang 500/330 kV (F2) transformer for	$9,407 Does not appear in

(This constraint was also identified on the Victoria–New South Wales, Heywood and Basslink interconnectors).		no contingencies, for radial/parallel modes and Yallourn W1 on the 500 or 220 kV. AEMO notes that these constraint equations maintain flow on the South Morang F2 transformer below its continuous rating. AEMO considers that the combination of these three constraint equations will bind for a similar amount in 2014.	top ten constraints with a market impact in either Victoria or New South Wales.
VSML_220	67.9	System normal constraint, upper limit of 220 MW on Victoria to South Australia on Murraylink.	$65,147 Does not appear in top ten constraints with a market impact in either Victoria or New South Wales.
V>>SML_NIL_7A	72.0	System normal constraint, avoid overloading Ballarat North to Buangor 66 kV line on trip of the Ballarat to Waubra to Horsham 220 kV line. This constraint equation only binds during periods of high demands in the Victorian state grid (220 kV system in northern western Victoria) and for high flows on Murraylink into South Australia.	$34,306 Does not appear in top ten constraints with a market impact in either Victoria or New South Wales.
South Australia to Victoria limits			
S>V_NIL_NIL_RBNW	51.7	System normal constraint, avoid overloading the North West Bend to Robertstown 132 kV line on no line trips.	$433,772 (number three in top ten constraints with largest market impact in South Australia).
V>>V_NIL_1B	13.5	System normal constraint, to avoid overloading Dederang to Murray No.2 330 kV line for trip of the Dederang to Murray No.1 330 kV line. This constraint equation binds for high transfers from New South Wales to Victoria with the DBUSS (Dederang bus splitting scheme) active.	$40,047 (number ten in top ten constraints with largest market impact in New South Wales).
S>>V_NIL_NOTI_NOTI_3	68.8	System normal constraint, with Torrens Island 66kV CB6W2, CB6W3 & CB6E6 open; avoid	$192,236 (number five in top

		overload of Torrens Island–New Osborne 66kV No.4 line on trip of Torrens Island–New Osborne 66kV No.3 line. These constraint equations manage the flows on the Torrens Island to New Osborne No.3 and No.4 66 kV lines for different configurations of the Torrens Island 66 kV bus. The different constraint equations were created in early 2013 following the splitting of the Torrens Island 66 kV bus. Their binding results have been combined. These constraint equations generally bind for high output from the Quarantine gas turbines.	ten constraints with largest market impact in New South Wales).

[a] The market impact is calculated by adding up the marginal values from the marginal constraint cost re-run. To that end, the constraint is relaxed marginally (by 1 MW). This will result in a different dispatch pattern, with different associated costs, compared to the situation under the full constraint. This is done for each dispatch interval during the number of hours a constraint was binding. These values are subsequently added up to provide a total marginal market impact.

Source: AEMO, *NEM constraint report 2013*, April 2014. pp13-15, 20-22, 26-27 and AEMO, NEM constraint report 2013 supplementary data.

F.3 Network constraints on the Murraylink interconnector

F.3.1 Findings from the 2013 transmission network development plan

The 2013 transmission network development plan did not find the need for upgrade of the Murraylink interconnector transfer capability under its modelling assumptions.

Regarding connections to neighbouring zones in Victoria, the network planning report notes that the increase in the amount of wind generation capacity in the Country Victoria zone could lead to constraints on a number of lines, including the Moorabool–Ballarat 220 kV and Red Cliffs–Wemen–Kerang 220 kV lines.

In relation to the main transmission corridors in South Australia, the network planning report identified a limitation on the Robertstown–North West Bend 132 kV line as an emerging reliability network limitation. Details and results of ElectraNet and AEMO's joint planning studies related to the Riverland region of South Australia are summarised below.

F.3.2 Findings from AEMO's Victorian transmission annual planning report

In relation to identified network constraints on the Moorabool–Ballarat and Ballarat–Bendigo 220 kV lines, AEMO published a project assessment conclusion report under a RIT-T in October 2013. The preferred option in this report is to install a wind monitoring facility on the Ballarat–Bendigo 220 kV line in 2015-16 (stage 1), followed by installing the third Moorabool–Ballarat 220 kV circuit in 2017-18 (stage 2), and up-rating the Ballarat–Bendigo 220 kV to a maximum operating temperature of 82 °C in 2019-20 (stage 3).[62]

This upgrade is expected to increase the combined capacity of existing Moorabool–Ballarat lines by 65 percent and the Ballarat–Bendigo 220 kV line by about 50 percent. AEMO noted in an update to the project assessment conclusion report published in June 2014 that stage 3 of the preferred option could be brought forward to 2018-19, or substituted with a non-network option to contract generation. The net market benefits between these two options was very small and AEMO indicated it would seek firm quotes on the network and non-network options via a tender process.[63]

In relation to the Red Cliffs–Wemen–Kerang 220 kV line, as noted in section D.3.2 above, AEMO is currently monitoring constraints on this line in the event that significant new wind generation is connected. AEMO have indicated that this line may be replaced with a new double circuit in the future if significant network constraints develop.[64]

F.3.3 Findings from ElectraNet's South Australian transmission annual planning report

ElectraNet's 2014 transmission planning report notes that currently, transfer capacity from South Australia into the Riverland area is limited by the thermal rating of the Robertstown–North West Bend 132 kV line under maximum demand operating conditions. The overload of this line can be avoided if import capacity from Murraylink is maintained above a certain threshold.[65]

Transfer from Murraylink into South Australia is at times restricted below the nominal 220 MVA capability of Murraylink due to constraints in the Victorian network. These constraints have the potential to restrict the capability of Murraylink below that required to adequately support the Riverland loads.

From ElectraNet's experience during the summer of 2013-14, Murraylink was no longer able to provide the import capacity required to meet the security of supply requirements to Riverland customers over the summer.

With completion of the Western Victoria reinforcement RIT-T, AEMO intends to progressively augment the Regional Victorian network. These augmentations should help facilitate increased transfer from Murraylink into South Australia. However, AEMO's modelling indicated that for a range of scenarios, over a 15 year horizon, in the absence of future generation on the Western Victoria 220 kV system, Murraylink

62 AEMO, *Victorian transmission annual planning report 2014*, June 2014, p45.

63 ibid, p47.

64 ibid, p64.

65 ElectraNet, *South Australian transmission annual planning report 2014*, June 2014, pp31, 53-54, 93-98.

would not be capable of supporting the Riverland under Victorian ten percent POE demand conditions.

To provide increased transfer capacity into the Riverland region, ElectraNet and AEMO considered a range of augmentations through a joint planning process. The results of this process will be published in a joint planning report later in 2014. The recommendations are that ElectraNet would:

- Implement dynamic ratings on the Robertstown–North West Bend No. 1 132 kV line and on the Robertstown–MWP3 132 kV line section in 2014;
- Increase line clearance on the Robertstown–North West Bend No. 1 132 kV line to improve the summer thermal rating in 2015;
- Monitor with AEMO, the ability of Murraylink to provide capacity support for the Riverland region in future years; and
- Augment the capacity of the South Australian transmission network to supply the Riverland from 2023.[66]

ElectraNet noted that these recommendations are consistent with the 2013 transmission network development plan's identified transfer constraints on the Robertstown–North West Bend 132 kV line. ElectraNet observed that the dynamic ratings and increased line clearance would restore reliability to the Riverland region by 2014-15, but load shedding may still be required in the Riverland and North West Victorian regions in the event of a critical contingency in the Regional Victorian transmission network.

F.4 Summary of projects for identified network constraints

In summary, the Commission does not consider there to be any transmission network constraints on the Murraylink interconnector, or in the transmission corridors around this interconnector in Victoria and South Australia that are not being addressed by the relevant jurisdictional planning bodies in their transmission annual planning reports.

Table F.2 provides a summary of the projects impacting on the Murraylink interconnector that are noted in the 2013 transmission network development plan and how these constraints are being addressed in AEMO and ElectraNet's transmission annual planning report.

66 This augmentation would be subject to the absence of generation connection to the Western Victorian 220 kV network that would enable Murraylink to support the Riverland 132 kV network during ten percent POE conditions and non-network solutions in the Riverland.

Table F.2 Summary of project outcomes for the Murraylink interconnector

Report limitation identified	Project	Purpose	Project status
2013 NTNDP (Limitation on the main transmission network).	Robertson–North West Bend 132 kV line.	Increase supply capacity on the Robertson–North West Bend line during times of peak load conditions in the Riverland area when Murraylink is not importing into South Australia.	ElectraNet and AEMO are undertaking a joint planning process with the results due to be published in late 2014.
2013 NTNDP (Potential economic dispatch limitation).	Robertson–North West Bend 132 kV line.	Reduce transmission network constraints as a result of high levels of wind generation in North South Australia.	ElectraNet and AEMO are undertaking a joint planning process with the results due to be published in late 2014.

G Review of Basslink interconnector

> The Commission does not consider there to be any transmission network constraints on the Basslink interconnector that are not being addressed by the relevant jurisdictional planning bodies in their transmission annual planning reports. There are no network constraints in the main transmission corridors around the interconnector in Victoria and Tasmania that are not being addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a participant under its last resort planning powers.

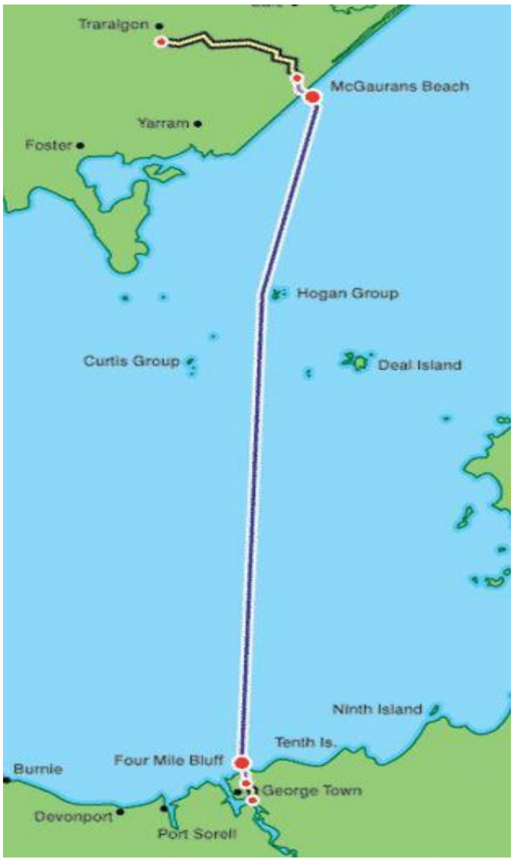
This section outlines the Commission's analysis in support of this conclusion. This analysis includes:

- an overview of the Basslink interconnector;
- a review of the binding constraint equations that most often set the limits on this interconnector from AEMO's 2013 constraint report;
- a review of the emerging transmission network constraints affecting this interconnector from the 2013 transmission network development plan;
- a review of Transend and AEMO's transmission annual planning reports on projects to address constraints on the interconnector and the main transmission corridors; and
- a summary of the projects identified to reduce transmission network constraints.

G.1 Overview of Basslink interconnector

Victoria and Tasmania are connected via the Basslink interconnector. Basslink is a direct current (DC) interconnection between George Town in Tasmania and Loy Yang in the Latrobe Valley area in Victoria. Basslink is an unregulated merchant link that was commissioned in early 2006 after Tasmania joined the NEM. Basslink is owned by CitySpring Infrastructure Trust. Unlike the other DC lines in the NEM, Basslink has a frequency controller and is able to transfer frequency control ancillary services.

Figure G.1 Basslink interconnector



Source: Basslink home page, www.basslink.com.au.

The Latrobe Valley area has a significant amount of coal-fired generation. It is a major exporter of energy, principally to Melbourne and Moorabool through to Heywood (via its 500 kV and 220 kV transmission networks – the 'Eastern corridor'), and also to Regional Victoria and Tasmania. Under AEMO's carbon price planning scenario in the 2013 transmission network development plan, 19 percent of brown coal-fired generation is retired in the outlook period (1200 MW between 2015-16 and 2016-17). This generation is expected to be replaced by wind and some gas-fired generation. Under AEMO's zero carbon price planning scenario, no brown coal-fired generation is expected to be retired over the outlook period to 2037-38.

The Tasmanian region has a significant amount of hydroelectric generation. This generation is geographically dispersed across the region. In the modelling for the 2013 transmission network development plan, up to 977 MW of additional wind generation is expected to be operational from 2019-20 onwards in this region.

As Basslink is an unregulated merchant interconnector and therefore not subject to the regulatory investment test for transmission, if the Commission identified a deficiency in the planning arrangements on the interconnector itself, the Commission would not be able to direct Basslink under the last resort planning power. However, if the identified constraints could be alleviated in the transmission corridors connecting to Basslink, or through the construction of another interconnector, the Commission would be able to direct the jurisdictional planning bodies in either Victoria or Tasmania.

G.2 Findings from 2013 constraints report

The majority of constraints on Basslink transfers are due to frequency control ancillary service constraint equations for both mainland and Tasmanian contingency events. Similar to previous years, the majority of flows and binding hours were from Tasmania to Victoria. The binding hours were on average higher in 2013 when compared with 2012.

Tasmania to Victoria transfers are mainly limited by the energy constraint equations for the South Morang F2 transformer overload, or the transient over-voltage at George Town.

For Basslink flows from Victoria to Tasmania, the energy constraints are due to the transient stability limit for a fault and trip of Hazelwood–South Morang line.

The top three most binding system normal constraints on the Basslink in each direction are outlined in Table G.1.

Table G.1 Binding constraint equations setting the Basslink limits in 2013

Tasmania to Victoria limits			
Equation ID	**Hours binding in 2013**	**Description**	**Market impact (with position in top ten market impacts per region)[a]**
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P (This constraint was also identified on the Victoria–New South Wales, Heywood and Murraylink interconnectors).	171.5	System normal constraint, avoid overloading the South Morang 500/330 kV (F2) transformer for no contingencies, for radial/parallel modes and Yallourn W1 on the 500 or 220 kV. AEMO notes that these constraint equations maintain flow on the South Morang F2 transformer below its continuous rating. AEMO considers that the combination of these three constraint equations will bind for a similar amount in 2014.	$9,407 Does not appear in top ten constraints with a market impact in either Victoria or Tasmania.
T^V_NIL_BL_6	86.6	System normal constraint, prevent transient over-voltage (TOV) at Georgetown 220 kV bus for loss of Basslink.	$12,858 Does not appear in top ten constraints with a market impact in either Victoria or

			Tasmania.
T^V_NIL_8	13.9	System normal constraint, Tamar Valley Combined Cycle GT OOS, prevent voltage collapse at Georgetown 220 kV bus for loss of a Sheffield to George Town 220 kV line, swamped if TVCC in service.	$1,492 Does not appear in top ten constraints with a market impact in either Victoria or Tasmania.
Victoria to Tasmania limits			
T>>T_NIL_BL_EXP_6E	73.0	System normal constraint, avoid overloading a Sheffield to Georgetown 220 kV line for trip of the parallel Sheffield to Georgetown 220 kV line considering NCSPS action.	$25,118 Does not appear in top ten constraints with a market impact in either Victoria or Tasmania.
T>>T_NIL_BL_EXP_5F	42.4	System normal constraint, avoid overloading a Hadspen to George Town 220 kV line for trip of the other Hadspen to George Town 220 kV line considering NCSPS action.	$141,737 (number seven in top ten constraints with largest market impact in Tasmania).
VTBL_ROC	14.8	System normal constraint, rate of change (Victoria to Tasmania) limit (200 MW / 5 minute) for Basslink.	$2,637 Does not appear in top ten constraints with a market impact in either Victoria or Tasmania.

[a] The market impact is calculated by adding up the marginal values from the marginal constraint cost re-run. To that end, the constraint is relaxed marginally (by 1 MW). This will result in a different dispatch pattern, with different associated costs, compared to the situation under the full constraint. This is done for each dispatch interval during the number of hours a constraint was binding. These values are subsequently added up to provide a total marginal market impact.

Source: AEMO, *NEM constraint report 2013*, April 2014. pp13-15, 20-22, 26-27 and AEMO, NEM constraint report 2013 supplementary data.

G.3 Network constraints on the Basslink interconnector

G.3.1 Findings from the 2013 transmission network development plan

As a result of the reduced energy and demand growth forecasts throughout the NEM, the 2013 transmission network development plan did not identify any forecast network constraints for Basslink.

The 2013 planning report also did not identify any network constraints on the main transmission network, or emerging reliability constraints for Tasmania. However, over the long-term to 2037-38, two potential economic dispatch constraints were identified for Tasmania. In addition, a further issue was raised relating to the integration of wind generation in the Tasmanian region. Transend's assessment of these issues is outlined in section G.3.3.[67]

For the Victorian side of Basslink, the 2013 network planning report did not identify any transmission network constraints in the Latrobe Valley over the outlook period. However, between 2018-19 and 2037-38, a number of emerging reliability constraints were identified in the Greater Melbourne transmission corridor that may restrict power transfer capability from the Latrobe Valley and Basslink. AEMO's assessment of these emerging issues and its response is discussed in section G.3.2.

G.3.2 Findings from AEMO's Victorian transmission annual planning report

AEMO did not identify any transmission network constraints in the 'Eastern corridor' from Basslink through the Latrobe Valley into Greater Melbourne in its 2014 transmission annual planning report. In response to the emerging network constraints identified in the 2013 transmission network development plan, AEMO identified loading of the Rowville 500/220 kV transformer as a priority limitation. AEMO is also actively monitoring the remaining five identified constraints.

Priority transmission network limitation

The Rowville 500/220 kV transformer is a key component in supplying electricity from the 500 kV transmission network to the Eastern Melbourne Metropolitan area. AEMO noted that depending on Yallourn generation, overloading of this transformer can occur during peak demand conditions with all transmission plant in service. When Yallourn generation is at capacity and supplying electricity directly to the 220 kV network, the Rowville transformer is expected to reach its load carrying capacity by around 2020-21.

AEMO is considering a number of network and possible non-network options for alleviating this limitation. AEMO has concluded that the market benefits associated with the identified network options are sufficient to justify augmentation by approximately 2021-22, which is beyond the augmentation project lead time as an outcome from the Eastern Metropolitan Regional Thermal RIT-T. Therefore, AEMO have committed to review this limitation as well as the options and their timing in 2014-15.

Network constraints being monitored by AEMO

AEMO is also monitoring a number of network constraints, which includes those identified in the 2013 transmission network development plan. Those projects that reinforce the Eastern transmission corridor and are relevant to the 2013 network planning report include:

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67 Note: from 1 July 2014, Transend and Aurora Energy the Tasmanian transmission and distribution network owners were amalgamated by the government and renamed TasNetworks.

- Rowville–Ringwood 220 kV line loading – possible connection of the Ringwood terminal station to the existing Rowville–Templestowe 220 kV line in the event of load growth or additional loads connected to Ringwood terminal station.

- Ringwood–Thomastown 220 kV line loading – construction of a third 500/220 kV transformer at Rowville in the event of load growth or additional loads connected to Ringwood terminal station. This option was identified as part of the Eastern Metropolitan Regional Thermal RIT-T.

- Templestowe–Thomastown 220 kV line loading – cut-in the Thomastown–Ringwood 220 kV line at Templestowe, or a construction of a third 500/220 kV transformer at Rowville in the event of load growth in the Melbourne metropolitan area.

- South Morang H1 330/220 kV transformer loading – replacement of the existing transformer with a higher rated unit to alleviate increased demand in metropolitan Melbourne and/or increased import from New South Wales.

- South Morang–Thomastown No. 1 and No. 2 220 kV line loading – construction of a third 500/220 kV transformer at Rowville in the event of load growth in the metropolitan Melbourne area. This option was identified as part of the Eastern Metropolitan Regional Thermal RIT-T.

- Cranbourne A1 500/220 kV transformer loading – construction of a new 500/220 kV transformer at Cranbourne terminal station to alleviate load growth around the metropolitan Melbourne area.

In the event that AEMO considers that any of these transmission network constraints are constraining the network, AEMO will undertake further analysis and initiate a regulatory test for transmission if required.

G.3.3 Findings from Transend's Tasmanian transmission annual planning report

Transend's annual planning report contained the following commentary about the network constraints identified in the 2013 transmission network development plan. In relation to the potential network constraints on the Burnie–Sheffield and Sheffield–Palmerston transmission corridors, Transend noted that these constraints have been investigated in the past. In the event that connection enquiries or connection applications relate to the addition of significant generation on these lines, network constraints are expected to arise. Currently Transend indicated that there are no proposals for significant wind farms in these areas, and there is no driver to consider increasing the capacity of these lines. Transend will consider this issue in detail as part of any connection application assessment.[68]

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68 Transend, *Tasmanian transmission annual planning report 2014*, June 2014, p83.

Transend also addressed the issue of potential network constraints arising from the integration of wind generation in the Tasmanian region. The 2013 transmission network development plan identified the likely curtailment of new entry wind generation as a result of multiple network constraints and challenges with power system frequency control due to the displacement of conventional generation. This is due to the design and performance characteristics of many new forms of renewable generation (most notably wind and solar photovoltaic) being such that they are not equivalent and cannot be directly substituted in place of synchronous machines.[69]

Two characteristics which are relevant to the operation of Basslink, and the Tasmanian power system more broadly, are the limited contribution of inertia and fault level coming from solar photovoltaic and wind generation technologies. Transend noted that since September 2013, the capacity of wind generation has exceeded 300 MW. This has provided the first insight into the types on new operational constraints that can result from the connection of a large amount of non-synchronous generation.

To address these concerns, Transend is maintaining a close working relationship with AEMO and investigating these issues further. A number of modifications have been implemented, including amended frequency control ancillary service calculations and the first rate-of-change-of-frequency constraint equation in the national electricity market.[70]

G.4 Summary of projects for identified network constraints

In summary, the Commission does not consider there to be any transmission network constraints on the Basslink interconnector, or in the transmission corridors around this interconnector in Victoria and Tasmania that are not being addressed by the relevant jurisdictional planning bodies in their transmission annual planning reports.

Table G.2 provides a summary of the projects impacting on the Basslink interconnector that are noted in the 2013 transmission network development plan and how these constraints are being addressed in AEMO and Transend's transmission annual planning reports.

69 ibid, p93.

70 Wind generating units do not contribute to power system inertia or raise FCAS. Therefore, going forward if wind generation replaces synchronous generators, the Tasmanian system inertia could drop to a level where credible contingencies could result in under frequency load shedding. To prevent this from occurring, Transend have developed with AEMO and implemented a rate of change of frequency constraint. The constraint limits Basslink flow, wind farm output, and the output of the largest synchronous generator depending on system inertia and load. The constraint ensures that, should a credible contingency occur, the Tasmanian power system frequency does not fall so quickly that under-frequency load shedding occurs before generator FCAS is able to respond.

Table G.2 Summary of project outcomes for the Basslink interconnector

Report limitation identified	Project	Purpose	Project status
2013 NTNDP (Limitation on the main transmission network)	Rowville 500/220 kV transformer and/or Cranbourne 500/220 kV transformer.	Reduce the potential for overload of the Rowville 500/220 kV transformer for an outage of the Cranbourne 500/220 kV transformer (and vice versa).	Limitation forecast to occur between 2018-19 and 2022-23. AEMO have committed to review this limitation as well as the options and their timing in 2014-15.
2013 NTNDP (Limitation on the main transmission network).	Thomastown–Templestowe 220 kV line and Thomastown–Ringwood 220 kV line.	Meet load growth in the Melbourne metropolitan area.	This transmission network limitation is being monitored by AEMO.
2013 NTNDP (Limitation on the main transmission network).	Rowville 500/220 kV transformer, South Morang 330/220 kV transformers and South Morang–Thomastown 220 kV line.	Meet load growth in the metropolitan Melbourne area.	This transmission network limitation is being monitored by AEMO.
2013 NTNDP (Potential economic dispatch limitation).	Burnie–Sheffield transmission corridor.	Reduce transmission network constraints as a result of high levels of new generation in North-West Tasmania.	No new generation planned in this corridor. Transend will evaluate as part of any connection application assessment.
2013 NTNDP (Potential economic dispatch limitation).	Palmerston–Sheffield transmission corridor.	Reduce transmission network constraints as a result of high levels of new generation in Central Tasmania.	No new generation planned in this corridor. Transend will evaluate as part of any connection application assessment.
2013 NTNDP (Potential constraints due to wind generation dispatch).	New wind generation in the Tasmanian region.	Investigate ways to limit transmission network constraints and improve power system frequency control due to new wind generation displacing conventional generation.	Transend is maintaining a close working relationship with AEMO and investigating these issues further.