REVIEW

Australian Energy Market Commission

DECISION REPORT

Last resort planning power - 2015 review

3 December 2015

Reference: EPR0046
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.

Summary

The Australian Energy Market Commission (AEMC or Commission) has determined not to exercise its last resort planning power in 2015.

From the analysis undertaken for the 2015 review, transmission network service providers are appropriately including inter-regional transmission priorities in their planning activities. The Commission therefore does not consider it is necessary to exercise the last resort planning power conferred on it under the National Electricity Rules.

Background

The last resort planning power is provided for in the National Electricity Rules. It allows the AEMC to direct one or more network service providers to apply the regulatory investment test for transmission to augmentation projects that are likely to relieve a forecast constraint on a national transmission flow path.

The purpose of the power is to ensure timely and efficient inter-regional transmission investment for the long term interests of consumers of electricity when other mechanisms to provide for the planning of this investment appear to have failed.

The AEMC must exercise its power in accordance with requirements in the National Electricity Rules and the last resort planning power guidelines.[1] The AEMC is also required to report annually on the matters which it has considered during that year in deciding whether to exercise the last resort planning power. To date, the AEMC has not exercised the last resort planning power.

Commission's decision

To assist it in determining whether to exercise the last resort planning power in 2015, and in accordance with the last resort planning power guidelines, the Commission has reviewed the transmission network service providers' annual planning reports, published in 2015, against the constraints on the network forecast by the Australian Energy Market Operator (AEMO) in the National Transmission Network Development Plans (NTNDPs) for 2014 and 2015, published in December 2013 and December 2014 respectively. The Commission has also considered the National Electricity Market constraints report 2014 published by the AEMO and other information such as relevant regulatory investment test reports published by the transmission network service providers.

With the exception of the upgrade of the Heywood interconnector between Victoria and South Australia, the NTNDPs for 2014 and 2015 did not identify a requirement for augmentation to the infrastructure connecting the different regions in the national

1 The current version of the AEMC's last resort planning power guidelines dated 24 September 2015 can be found at: www.aemc.gov.au/Australia-s-Energy-Market/Market-Legislation/Electricity-Guidelines-and-Standards

electricity market. The upgrade of the Heywood interconnector is due for completion in July 2016.[2]

Transmission network service providers continue to address or monitor constraints on the infrastructure connecting the national electricity market regions and the transmission infrastructure within their networks that could impact on inter-regional electricity flows in their 2015 transmission annual planning reports. For example, TransGrid and Powerlink have committed to continue to monitor constraints on the Queensland-NSW interconnector. ElectraNet is actively monitoring constraints in the south east of South Australia.

As the Commission has not identified a problem regarding the planning processes for inter-regional transmission infrastructure it has decided not to exercise the last resort planning power in 2015.

NTNDP for 2016

In November 2015, AEMO published the NTNDP for 2016. The Commission will assess whether transmission network service providers are addressing constraints identified by AEMO in this NTNDP after the transmission network service providers have published their 2016 transmission annual planning reports. At a high level, in the NTNDP for 2016 AEMO predicts that minimal new transmission infrastructure is required to transport power to consumers, continuing the trend seen in recent NTNDPs.

2 The need to upgrade the Heywood interconnector has consequently not been identified in the NTNDP for 2016, published by AEMO in November 2015.

Contents

1 Background and approach

1.1 Background

The interconnected transmission network in the national electricity market (NEM) is important for facilitating a reliable supply of electricity to consumers and to support the NEM wholesale market by allowing electricity to be bought and sold across regions.

Responsibility for planning of the transmission network in the NEM is generally shared between the Australian Energy Market Operator (AEMO) in its role as National Transmission Planner and the transmission network service providers (TNSPs) in the NEM.[3] These responsibilities are complemented by the Australian Energy Market Commission’s (AEMC or Commission's) last resort planning power (LRPP).

The LRPP allows the AEMC to direct one or more network service providers (NSPs) to apply the regulatory investment test for transmission (RIT-T) to augmentation projects that are likely to relieve a forecast constraint on a national transmission flow path.[4] These flow paths include the infrastructure that allows electricity to be physically transferred across the NEM regional boundaries, known as interconnectors. Further information on the NEM interconnectors is provided in Appendix A of this report.

The purpose of the LRPP is to ensure timely and efficient inter-regional transmission investment for the long term interests of consumers of electricity when other mechanisms for the planning of this investment appear to have failed. Being a last resort mechanism, it is designed to only be utilised where there is a clear indication that regular planning processes have resulted in a planning gap regarding inter regional transmission infrastructure.

The AEMC must decide whether, and if so how, to exercise the LRPP in accordance with requirements in the National Electricity Rules (NER) and with its LRPP guidelines. The NER also require the AEMC to report annually on the matters which it has considered during that year in deciding whether to exercise the LRPP. This is the subject of this report.

3 Note that AEMO is also responsible for planning and directing augmentations to the electricity transmission network in Victoria. This means it is a TNSP for these purposes under the National Electricity Rules.

4 Clause 5.10.2 of the NER defines a potential transmission project as an investment in a transmission asset of a TNSP which is: an augmentation; has an estimated capital cost in excess of $5 million, as varied in accordance with a cost threshold determination; and the person who identifies the project considers is likely, if constructed, to relieve forecast constraints in respect of national transmission flow paths between regional reference nodes.

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

As set out in the LRPP guidelines, the AEMC adopts a three stage approach to the LRPP:

- The first stage involves reviewing relevant planning documents to determine whether there are any inter regional constraints in the NEM that have not been adequately examined by TNSPs, that is, whether there are any planning gaps.
- The second stage is only undertaken if any planning gaps have been identified in stage one. It involves more closely examining these gaps to determine whether exercising the LRPP is likely to meet the national electricity objective.
- The third stage is only undertaken if the AEMC considers it appropriate to exercise the LRPP in stage two. It focuses on who should be directed to undertake a RIT-T.

More detail on this approach can be found in the AEMC's LRPP guidelines.[5] These guidelines were recently updated by the AEMC.[6]

5 AEMC, *Last resort planning power guidelines*, 24 September 2015.

6 AEMC, *Review of the last resort planning power guidelines final decision*, 24 September 2015.

2 Commission's considerations and conclusions

The Commission considers TNSPs are adequately considering inter regional transmission constraints in the NEM and has therefore decided not to exercise the LRPP in 2015.

In making this decision the AEMC has considered:

- the National Transmission Network Development Plan (NTNDP) for 2014 published by AEMO in 2013 and the NTNDP for 2015 published by AEMO in 2014;
- the 2015 transmission annual planning reports for each region of the NEM published by TNSPs;
- the NEM constraint report for 2014 published by AEMO; and
- relevant regulatory investment tests for transmission that have recently been undertaken.

While both the NTNDP for 2014 and 2015 have been considered, the Commission has given significantly more weight to the NTNDP for 2015 as the constraints on the network forecast by AEMO in this report are based on more recent electricity demand forecasts. Further information on the information the Commission has considered in coming to its conclusion is provided in Appendix B of this report.

The details and analysis supporting the Commission's conclusion are contained in Appendices C to H of this report. These appendices provide a review of inter regional constraints identified by AEMO in planning documents and how the TNSPs are addressing these constraints in their annual planning reports. The analysis is presented by NEM interconnector.

NTNDP for 2016

In November 2015, AEMO published the NTNDP for 2016. The Commission will assess whether TNSPs are addressing constraints identified by AEMO in this NTNDP after the TNSPs have published their 2016 transmission annual planning reports. TNSPs are required to address issues raised in the NTNDP for 2016 in their 2016 annual planning reports. At a high level, in the NTNDP for 2016 AEMO predicts that minimal new transmission infrastructure is required to transport power to consumers, continuing the trend seen in recent NTNDPs.[7]

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7 AEMO, *National Transmission Network Development Plan*, November 2015, p15.

Abbreviations

AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
LRPP	last resort planning power
MVAr	mega voltage ampere reactive
NEM	national electricity market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NTNDP	National Transmission Network Development Plan
NSP	network service provider
QNI	Queensland–New South Wales interconnector
RIT-T	regulatory investment test for transmission
SVC	static var compensator
TNSP	transmission network service provider

A Interconnection and constraints

A.1 Interconnection

Almost 40,000 km of transmission lines and associated infrastructure make up the physically interconnected NEM transmission network.[8]

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:[9]

- 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 benefiting consumers by increasing competition between generators and retailers; 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 reliability of supply across the NEM 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, the cost of generation and levels of demand - regions are either net importers or net exporters of electricity. Figure A.1 expresses inter-regional trade in net flows as a percentage of regional energy demand for each region of the NEM.

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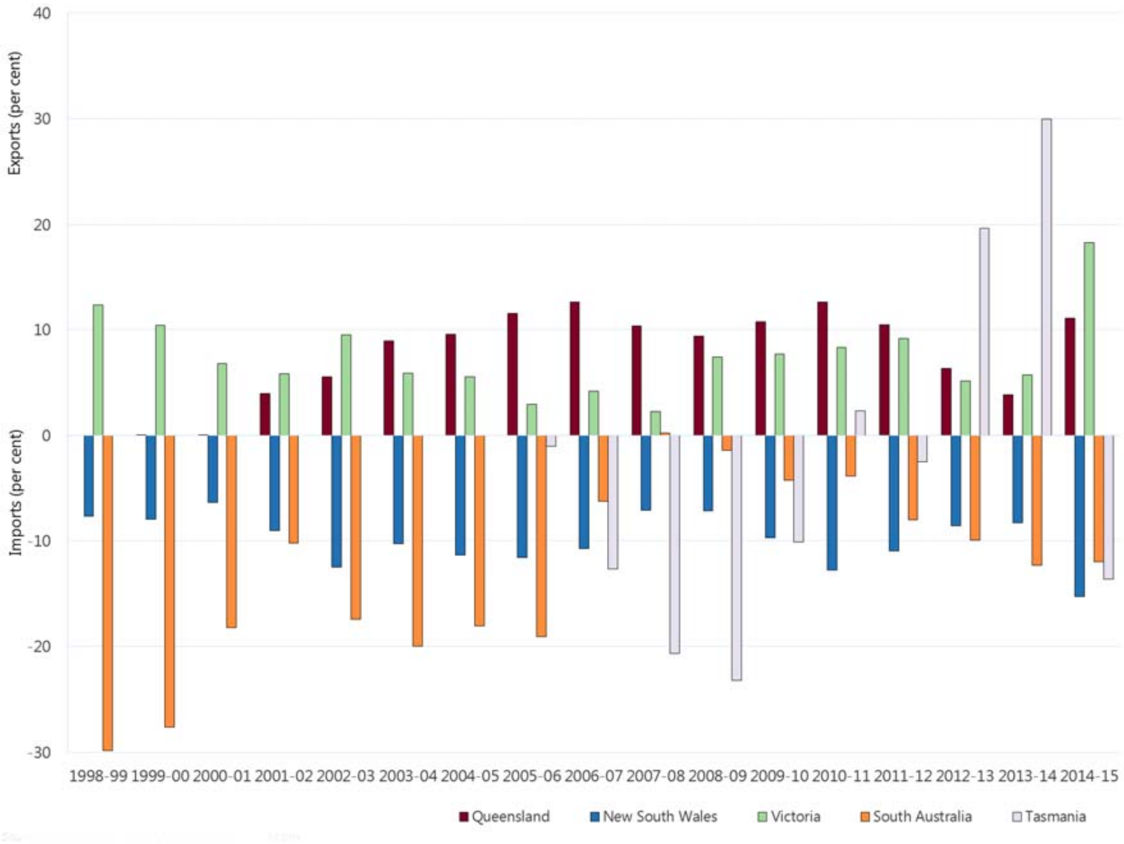
8 AEMO website, www.aemo.com.au, viewed 6 November 2015.

9 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 electricity consumption**



Source: Industry statistics on the Australian Energy Regulator website. Available from www.aer.gov.au/industry-information/industry-statistics, last viewed 6 November 2015.

The growing share of electricity generation coming from renewable energy sources may 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 in some regions; and
- the intermittence 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.

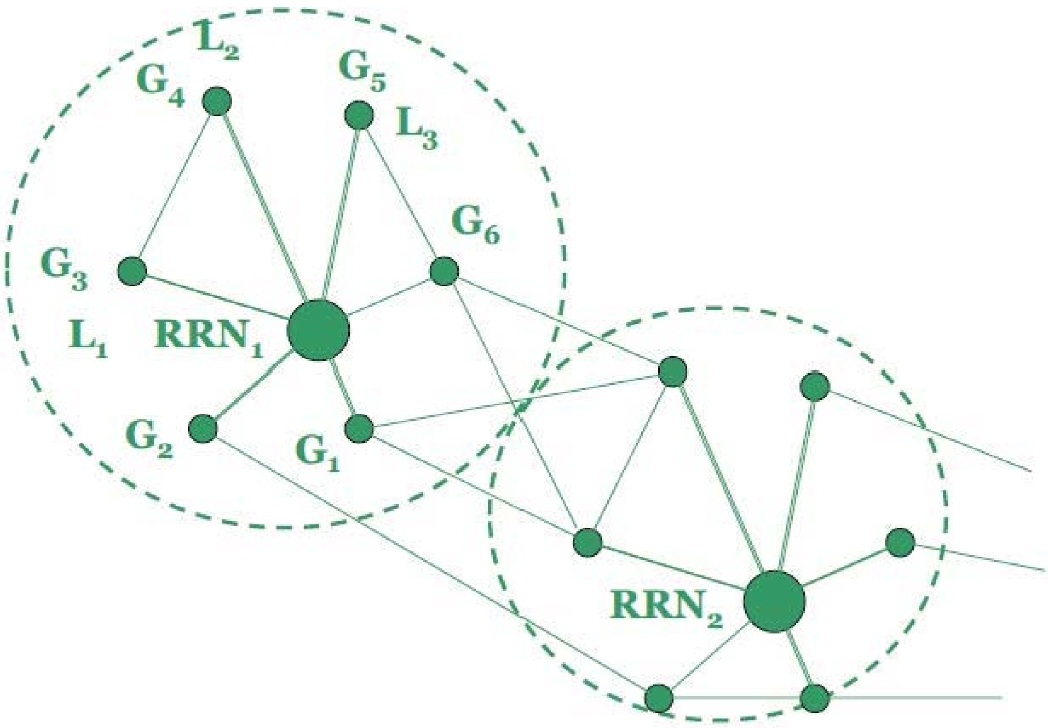
The importance of the transmission network in the functioning of the NEM leads to the need for it to be reliable, as outages or failures of the network can be disruptive and costly.

TNSPs 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. Physically, this infrastructure cannot necessarily be distinguished from other parts of the transmission network. Schematically, this can be represented by the diagram in Figure A.2.

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

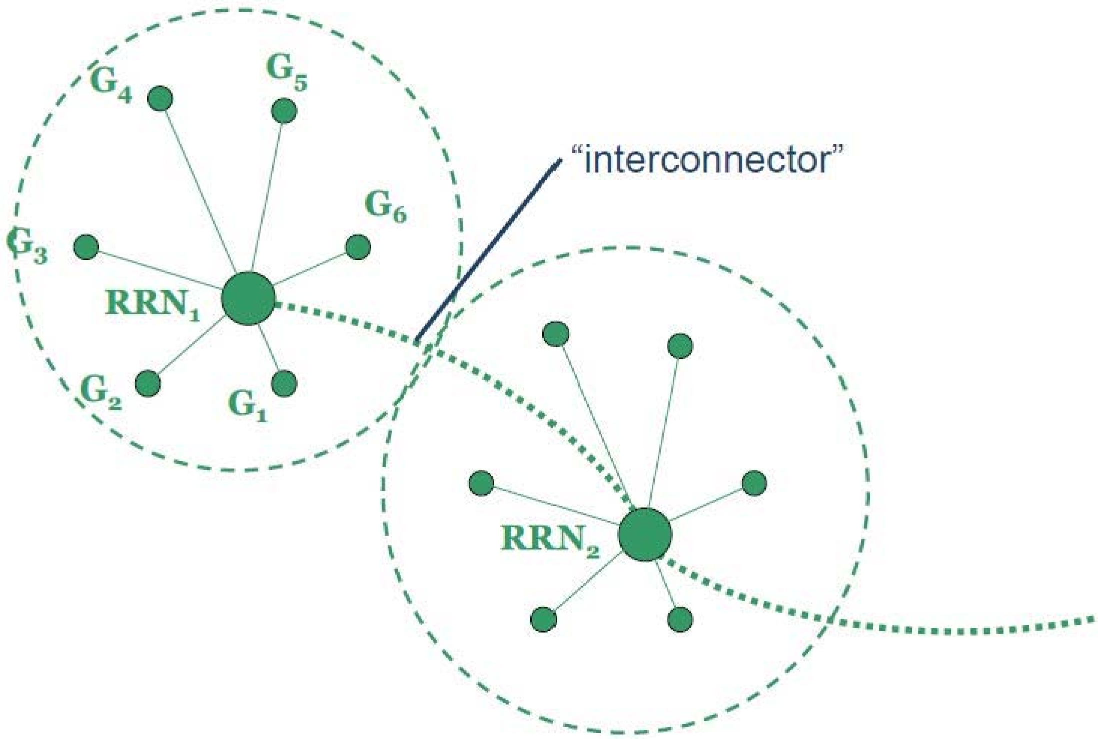


Note: ‘RRN’ refers to regional reference node, ‘G’ to generator and ‘L’ to load (demand) centres

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 to the 'physical' interconnectors, in addition to the transmission flow-paths and/or corridors leading up to the interconnectors when considering whether to exercise 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 (market) interconnectors.[10]

A regulated interconnector is an interconnector that forms part of a TNSP's regulated assets. The TNSP owning the interconnector can recover a maximum annual revenue set by the Australian Energy Regulator. The revenue is collected by distribution network service providers as part of the network charges levied on retailers. Generally, a TNSP is required to undertake a regulatory investment test for transmission (RIT-T) when planning for the building of a new regulated interconnector or increasing the capacity of an existing regulated interconnector.[11]

An unregulated (or market) 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. Expansions of unregulated interconnectors are not required to undergo the regulatory investment test evaluation. The only unregulated interconnector currently operating in the NEM is Basslink connecting Tasmania and Victoria.

10 See AEMO website, www.aemo.com.au, viewed 10 November 2015.

11 The RIT-T is discussed in more detail in Appendix B.4 of this report.

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.

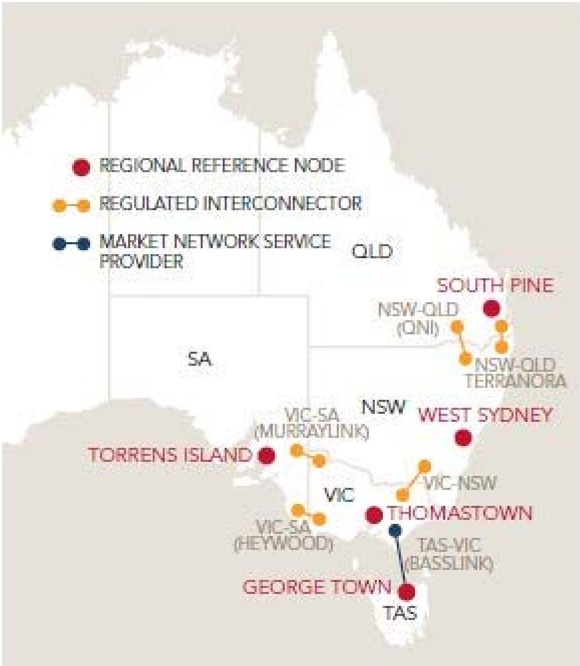
Table A.1 Interconnectors in the NEM

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

Source: AEMO website, www.aemo.com.au, viewed 10 November 2015.

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.[12]

A.3 Network constraints

The ability of the network to carry electricity (the 'transfer capability') is in practice affected by a range of factors.[13]

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, which it must be capable of carrying.

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:

12 AEMO's Interconnector Quarterly Performance Reports are available on AEMO's website, www.aemo.com.au, viewed 10 November 2015.

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

- 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 TNSPs will need to assess the costs and benefits of addressing constraints. Where it is economic to do so, constraints can be addressed by either:

- augmentations to the transmission infrastructure, called 'network options'.[14]
- solutions such as demand-side management and network support control ancillary services,[15] 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 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 considerations of net costs and benefits. In other words, some level of congestion is likely to be economically efficient.[16]

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

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

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

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

Box A.2 Congestion and inter-regional settlement residues[17]

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 in the importing region (the low-priced region). As a result, inter-regional

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

settlement residues can be negative. The cost of funding these negative settlement residues is ultimately borne by consumers in the importing region.[18]

18 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 Planning reports considered by the AEMC

This Appendix provides information on the planning reports the AEMC has considered to examine whether TNSPs are adequately examining inter regional constraints.

B.1 National Transmission Network Development Plans for 2014 and 2015

The National Transmission Network Development Plan (NTNDP) 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 NTNDP seeks to influence transmission investment by:

- providing a national focus on market benefits and transmission augmentations to support an efficient power system;
- proposing 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 alternatives, including demand-side and generation options.

For planning purposes, the NTNDP divides the NEM transmission network into sixteen zones, referred to as 'transmission zones'. These zones capture differences in generation technology capabilities, such as wind capacity, that exist within the NEM region and areas of potential congestion in the transmission corridors or flow paths linking the transmission zones.

Figure B.1 identifies the transmission zones and the main flow paths between these zones.

Figure B.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, *Planning methodology and input assumptions*, 30 January 2014, p5.

As required by the NER, the AEMC considers the NTNDP for the current and previous year when considering whether to exercise the LRPP.[19] The relevant NTNDPs are therefore the NTNDP for 2014 which was published by AEMO in December 2013, and the NTNDP for 2015 which was published by AEMO in December 2014. While both NTNDPs were considered, the Commission has given significantly more weight to the NTNDP for 2015 in its consideration of whether to exercise the LRPP as the investment needs identified by AEMO in this report are based on more recent electricity demand forecasts.

In the NTNDP for 2015, AEMO considered that two scenarios were credible:

- a medium energy consumption from centralised sources scenario (medium scenario); and
- a low energy consumption from centralised sources scenario (low scenario).[20]

The two scenarios are broadly defined in Table B.1.

19 NER clause 5.22(f)(2).

20 AEMO, *National Transmission Network Development Plan*, December 2014, pp8-9.

Table B.1 Scenarios in NTNDP for 2015

	Medium energy consumption from centralised sources	Low energy consumption from centralised sources
Energy consumption	Medium	Low
Level of consumer engagement[21]	High	High
Economic activity	Medium	Low

Source: AEMO, *2014 Planning and forecasting scenarios*, 11 February 2014, p4.

However, AEMO noted that no further thermal constraints requiring new network investment were identified in the low scenario beyond those already identified in the medium scenario. The low scenario was therefore not discussed in detail in the NTNDP for 2015.[22] More detail on the planning methodology and input assumptions used in the NTNDP for 2015 are published on AEMO's website.[23]

In November 2015, AEMO published the NTNDP for 2016. The Commission will assess whether TNSPs are addressing constraints identified by AEMO in this NTNDP after the TNSPs have published their 2016 transmission annual planning reports. TNSPs are required to address issues raised in the NTNDP for 2016 in their 2016 annual planning reports.

B.2 The NEM constraint report for 2014

The NEM constraint report published annually by AEMO contains details about constraint equation performance in the preceding calendar year.[24] 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 NTNDP, TNSPs have had the ability to use or consider this information to inform their annual planning reports. The relevant NEM constraint report for the 2015 LRPP review is the NEM constraint report for 2014 published by AEMO in April 2015.[25]

21 Highly engaged consumers adopt energy efficiency, distributed generation (rooftop PV), and demand-side management strategies to offset their energy consumption from the transmission network.

22 ibid.

23 www.aemo.gov.au, viewed 16 October 2015.

24 See for example, AEMO, *NEM constraint report 2014*, April 2015.

25 AEMO, *NEM constraint report 2014*, April 2015.

For the purpose of consideration of the LRPP, the Commission has analysed the 'system normal'[26] 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 Appendices C to H of this report.

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.[27] The top three market impacts for each interconnector from the NEM constraint report for 2014 in each direction is also outlined in the analysis on the individual interconnectors in Appendices C to H 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 appears in the constraint equations for the Heywood, Basslink, Murraylink, Victoria–New South Wales and the Queensland-New South Wales interconnectors.

B.3 2015 transmission annual planning reports

By 1 July each year, each TNSP must publish an annual planning report.[28] This report must set out the outcomes of a TNSPs annual planning review which a TNSP is required to conduct under the NER.[29] The annual planning review involves a TNSP analysing 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.[30] In addition, a TNSP must consider the potential for network augmentations or non-network alternatives to augmentations when conducing an annual planning review.[31]

Importantly, TNSPs are also required to take the most recent NTNDP into account when conducting their annual planning review.[32] In particular, when a TNSP

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

27 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.

28 NER clause 5.12.2(a).

29 NER clause 5.12.1(b).

30 NER clause 5.12.1(a).

31 NER clause 5.12.1(b)(4).

32 NER clause 5.12.1(b)(3).

proposes augmentations to the network, it must explain in its annual planning report how the proposed augmentations relate to the most recent NTNDP and the development strategies for current or potential national transmission flow paths specified in the NTNDP.[33] This provides coordination between the planning priorities identified by AEMO in the NTNDP regarding inter-regional flow paths and the planning activities undertaken by TNSPs for each jurisdiction. In addition to inter-regional flow paths, the TNSPs will typically also consider upgrades that primarily affect transmission flow paths within their regions.

The minimum forward planning period for the annual planning review and therefore that covered by the annual planning report is ten years.[34] The relevant transmission annual planning reports for the 2015 LRPP review are those published in 2015.

B.4 Regulatory investment test reports

The NER require that TNSPs must apply a regulatory investment test for transmission (RIT-T) for any augmentation projects with an estimated cost of more than $5 million.[35]

The purpose of the RIT-T 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.[36] The NER define a 'credible option' as an option or group of options that:

- address the identified need;
- is, or are, commercially and technically feasible; and
- can be implemented in sufficient time to meet the identified need.[37]

The costs associated with options for transmission augmentation must be weighed against the benefits they are likely to bring to the market. Investments may be undertaken to either meet reliability standards or to deliver a net market benefit, for example, economic expansion.[38]

33 NER clause 5.12.2(c)(6).

34 NER clause 5.12.1(c).

35 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 threshold will increase to $6 million on 1 January 2016 as a result of a cost thresholds review final determination made by the Australian Energy Regulator on 5 November 2015.

36 NER clause 5.16.1.

37 NER clause 5.15.2.

38 NER clause 5.16.1(c).

The NER also require 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.[39]

The procedure that a proponent must follow in conducting a regulatory investment test is also outlined in the NER.[40] Following completion of the regulatory investment procedure a project assessment conclusions report is published.

39 NER clause 5.16.1(c)(4).

40 NER clause 5.16.4.

C Review of the Queensland–New South Wales interconnector

There are no transmission network constraints on the Queensland–New South Wales interconnector that are not being addressed by the relevant TNSPs in their transmission annual planning reports. Similarly, there are no network constraints in the main transmission corridors around the interconnector in Queensland and NSW 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 NSP under its last resort planning power.

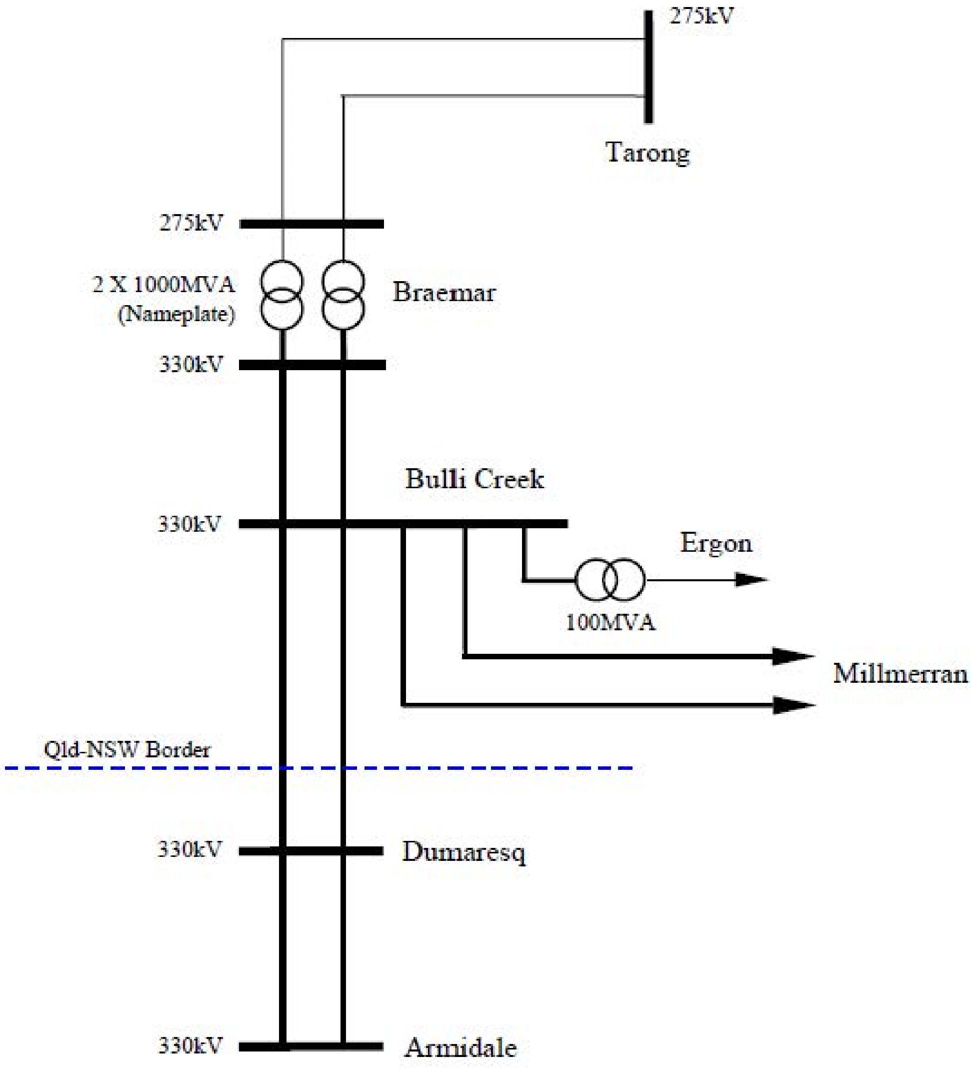
This section outlines the Commission's analysis in support of this conclusion. This analysis includes:

- 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 NEM constraint report for 2014;
- a review of the emerging transmission network constraints affecting this interconnector from the NTNDP for 2015, published in 2014;
- a review of TransGrid and Powerlink's 2015 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.

C.1 Overview of Queensland–New South Wales interconnector

The Queensland–New South Wales interconnector (QNI) connects the South West Queensland zone with the North NSW zone. It runs between Bulli Creek in Queensland and Dumaresq in NSW as set out in Figure C.1.

Figure C.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. The Northern NSW 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 NSW.

The flow on QNI is normally from Queensland into NSW. However, at times of high generation in NSW or low generation in Queensland, the flow can reverse and go from NSW to Queensland. Due to their close electrical proximity to the NSW side, both QNI and Terranora often appear on the left hand side of constraint equations.[41]

41 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.

C.2 Findings from the NEM constraint report for 2014

The transfer of electricity from NSW 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 NSW.[42]

Until November 2013, electrical transfer from NSW 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.[43]

Transfer from Queensland to NSW is normally limited by the transient stability limits for a fault on a Bulli Creek to Dumaresq line or frequency control ancillary services 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.

In 2014, electricity was mainly transferred from Queensland to NSW, reverting back to the historical norm after mainly flowing the other way in 2013. The top three most binding system normal constraints that affected flows on QNI in both directions for 2013 are outlined in Table C.1.

Table C.1 Binding constraint equations setting the QNI limits in 2014 (system normal)

NSW to Queensland limits			
Equation ID	**Hours binding in 2014**	**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).	72.1	To avoid voltage collapse for the loss of the largest Queensland generator.	$522,292 (number two in the top ten constraints with largest market impact in NSW)
N>>N-NIL__3_OPENED	4.6	To avoid overloading Liddell to Muswellbrook 330kV line on trip of Liddell to Tamworth 330kV line.	$441,872 (number three in the top ten constraints with largest market impact in NSW)
N^Q_NIL_A	4.6	To avoid voltage	$12,007 (number six

42 AEMO, *NEM constraint report 2015*, April 2015, p21.

43 ibid.

(This constraint was also identified on the Terranora (Directlink) interconnector).		collapse on loss of Liddell to Muswellbrook 330 kV line.	in the top ten constraints with largest market impact in NSW)
Queensland to NSW limits			
Q:N_NIL_AR_2L-G	784.4	To avoid transient instability for a two line to ground fault at Armidale.	$66,726 (number four in the top ten constraints with largest market impact in Queensland)
V::N_NILxxx (This constraint was also identified on the Vic-NSW, Heywood, Murraylink and Basslink interconnectors).	23.0	To prevent transient instability for fault and trip of a Hazlewood to South Morang 500 kV line.	$23,304 (this is a Victorian constraint)
Q:N_NIL_BI_POT	3.4	For high flows from Queensland to NSW. Either this constraint equation or Q:N_NIL_OSC or Q:N_NIL_BCK2L-G will bind.	$67 (number nine in the top ten constraints with largest market impact in Queensland)

[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 2014*, April 2015 and *NEM constraint report 2014 supplementary data*, April 2015.

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

C.3.1 Findings from the NTNDP for 2015

The NTNDP for 2015 identified a potential economic constraint on the Liddell-Muswell- Tamworth 330kV lines during the forecast period to 2033-34. AEMO considers that the flow on these lines, which transfer power to the Northern NSW zone and Queensland, may become congested at times of high northward flows on the QNI interconnector. It suggests this may occur following the retirement of the Redbank power station in the Hunter Valley which AEMO predicted will occur.[44] AEMO does not consider this potential constraint to be material at this stage.[45]

The NTNDP for 2015 did not identify any constraints in the transmission corridor leading to the QNI in Queensland.

C.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 in March 2014. Six options were included in the RIT-T analysis and discussed in the project assessment draft report:[46]

- Uprating of the the Northern NSW zone 330 kV transmission lines;
- Fifty percent series compensation of the interconnecting 330 kV lines between Armidale, Durmaresq and Bulli Creek;
- 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 project assessment draft report that may be found on Powerlink and TransGrid's websites. Each of these options was expected to have material inter regional network capability 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 the Northern NSW zone; and
- load growth.

44 AEMO, *National Transmission Network Development Plan*, December 2014, p19.

45 This constraint has also been identified in the NTNDP for 2016 published by AEMO in November 2015.

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

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 NSW to Queensland transmission capacity upgrade was deferred. AEMO stated that this project was excluded at the substantive proposal stage and that the NTNDP for 2014 did not identify a need to upgrade the QNI interconnector.[47]

In November 2014, Powerlink and Transgrid published a project assessment conclusions report. This report maintained the recommendation in the draft report to continue to monitor developments in key input assumptions. This recommendation was also supported by stakeholders in submissions to the draft report.[48]

C.3.3 Findings from Powerlink's 2015 transmission annual planning report for Queensland

Consistent with the NTNDP for 2015, Powerlink have not identified any emerging reliability or potential economic dispatch limitations across the main transmission network linking NTNDP zones within the Queensland region. As a result, Powerlink has not identified any projects in Queensland around QNI.

C.3.4 Findings from TransGrid's 2015 New South Wales transmission annual planning report

TransGrid outlined a number of possible network developments in the Northern NSW transmission zone 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 the Northern NSW zone. The projects included:

- 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 power flows to and from Queensland and increased generation developments (gas, solar and wind) in the

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

48 Powerlink and Transgrid, *Project assessment conclusions report, Development of the Queensland - NSW interconnector*, 13 November 2014, p7.

Northern NSW zone. This constraint was identified by AEMO in its NTNDP for 2015 as discussed in section C.3.1.

- Voltage control in the Northern NSW zone - the ability to maintain adequate voltage levels is the most constraining limitation on the NSW export capacity to Queensland. In particular, the ability to maintain adequate voltage levels at Tamworth, Armidale and Dumaresq is critical for inter-regional transfer.[49]

To improve the power transfer capability of the QNI interconnector in both directions, previous NTNDPs have recommended improvements to 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 NSW direction).
- A new 200 MVAr capacitor at the Armidale substation to increase the QNI interconnector's power transfer capability (in the NSW to Queensland direction). This project is due to be completed in late 2015.[50]

TransGrid's 2014 transmission annual planning report noted that the power oscillation damping control was installed on the Armidale SVC in 2013.[51] In relation to the second project, a tender for the refurbishment of one SVC at Armidale was issued by TransGrid in February 2014.[52] TransGrid are planning to complete this project in late 2015.[53]

Some possible network developments and committed projects undertaken by TransGrid in the Northern NSW zone are also relevant to the Terranora interconnector discussed in Appendix D.

C.4 Summary of projects for identified network constraints

There are no forecast transmission network constraints on QNI, or in the transmission corridors around QNI in Queensland and NSW that are not being adequately addressed by the relevant TNSPs in their 2015 annual planning reports. Table B.2 provides a summary of identified constraints and projects being undertaken by TNSPs that to deal with those constraints.

49 ibid, pp90-92.

50 ibid. p67.

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

52 Details of the tender may be found at the NSW eTendering website, https://tenders.nsw.gov.au/transgrid/ (archived). Last viewed 9 November 2015.

53 TransGrid, *New South Wales transmission annual planning report*, June 2015, p67.

Table C.2 Summary of constraints relating to the QNI interconnector and how these are being addressed by the relevant TNSPs

Report limitation identified	Details of constraint identified	Project to address constraint	Project status
Concluded RIT-T assessment	Increase the capability of QNI to transfer electricity between Queensland and NSW.	Upgrade of the Queensland-New South Wales interconnector (Powerlink and TransGrid)	Deferred as a result of lower demand growth and no clear net market benefits for any credible network and non-network options analysed. The capacity of the interconnector will be monitored along with developments in the NEM. The project will be re-evaluated should there be a change in circumstances. This is expected to be beyond five years at this stage.
NTNDP for 2015 (economic constraint)	Relieve future constraints in the Northern NSW zone, in particular between Liddell and Tamworth, at times of high northward flows on the QNI interconnector. AEMO did not specify the timing of the limitation within the NTNDP forecast period. However, it does not consider this limitation to be material at this stage.	Increase system capacity between Hunter Valley, Tamworth and Armidale (TransGrid)	Contingent on QNI being upgraded and new generation being connected in the Northern NSW zone. TransGrid have committed to reviewing this project at the same time as it undertakes a re-evaluation of the QNI upgrade with Powerlink (see above).

D Review of Terranora (Directlink) interconnector

There are no constraints on Terranora that are not being adequately addressed by the relevant TNSPs in their transmission annual planning reports. Similarly, there are no network constraints in the main transmission corridors around Terranora in Queensland and NSW that are not being adequately addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a NSP under its last resort planning powers.

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

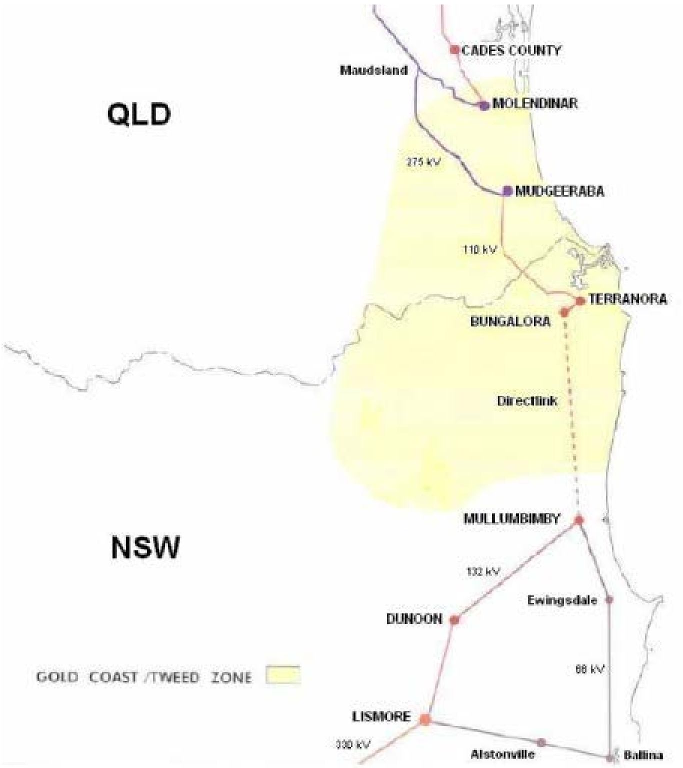
- an overview of the Terranora interconnector;
- a review of the binding constraint equations that most often set the limits on Terranora from AEMO's NEM constraint report for 2014;
- a review of the emerging transmission network constraints affecting the Terranora interconnector from the NTNDP for 2015 published by AEMO in December 2014;
- a review of Powerlink and TransGrid's 2015 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.

D.1 Overview of Terranora

The Terranora interconnector comprises the two 110 kV lines from Terranora in NSW to Mudgeeraba in the South East Queensland zone as set out in Figure D.1. The controllable element is a 180 MW direct current link between Terranora and Mullumbimby (both in NSW), known as Directlink, which consists of three separate direct current lines.[54] Directlink was commissioned in 2000, forming the first connection between NSW and Queensland. The Terranora interconnector is owned by Energy Infrastructure Investments Pty Ltd.

54 Contrary to an alternating current interconnector, where the voltage and current are at any point sinusoidal, in a direct current interconnector, the power is transferred using constant voltage and current.

Figure D.1 Terranora interconnector



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

D.2 Findings from the NEM constraint report for 2014

The majority of flows on this interconnector are towards NSW, so both the import and export values are negative unlike the other NEM interconnectors. It is usually constrained by thermal limits in the Northern NSW zone or the rate of change on Directlink.[55]

The Terranora interconnector often appears along with the Queensland to NSW interconnector (QNI) on the left hand side of the stability constraint equations, so both interconnectors may be constrained at the same time.[56]

The top three most binding, system normal, constraints in both directions for 2014 that affected flows on Terranora are listed in Table D.1. There were only two binding, system normal, constraints from Queensland to NSW.

In 2014, most of the time Terranora was restricted due to the outage of all three Directlink cables. All three Directlink cables were out for 70.3 days in 2014 compared with 158.1 days in 2013.[57]

55 AEMO, *NEM constraint report 2014*, April 2015, p20.

56 ibid.

Table D.1 Binding constraint equations setting the Terranora limits in 2014 (system normal)

NSW to Queensland limits			
Equation ID	**Hours binding in 2014**	**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 is the same as that identified for QNI).	14.6	To avoid voltage collapse for the loss of the largest Queensland generator.	$522,292 (number two in the top ten constraints with largest market impact in NSW)
NQTE_ROC	4.8	Rate of change limit (80MW/5 minute) for Terranora interconnector.	$49 (does not appear in top ten constraints with a market impact in either Queensland or NSW)
N^Q_NIL_A (This constraint is the same as that identified for QNI).	3.6	To avoid voltage collapse on loss of Liddell to Muswellbrook (83) 330 kV line.	$12,007 (does not appear in top ten constraints with a market impact in either Queensland or NSW)
Queensland to NSW limits			
Q>NIL_MUTE_757 & Q>NIL_MUTE_758	24.3	To avoid overloading a Mudgeeraba to Terranora (757 or 758) 110 kV line on no contingencies.	$17,162 (number nine in top ten constraints with a market impact in Queensland)
QNTE_ROC	3.8	Rate of change (Queensland to NSW) constraint (80 MW/5 Min) for Terranora Interconnector.	$96 (does not appear in top ten constraints with a market impact in either Queensland or NSW)

[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 2014*, April 2015 and *NEM constraint report 2014 supplementary data*, April 2015.

57 The outage of all three Directlink cables bound for a total of 342.5 hours in 2014 and was the most binding interconnector constraint in the national electricity market. Similarly, instances where two Directlink cables were out equated to 169.8 days, or 51.4 binding hours in 2014.

D.3 Network constraints affecting Terranora

D.3.1 Findings from the NTNDP for 2015

AEMO does not identify the need for increased power transfer capability between Queensland and NSW over the Terranora interconnector in the NTNDP for 2015. Therefore, no augmentations of the Terranora interconnector are listed in the NTNDP for 2015. However, AEMO does identify the potential for future constraints in the Northern NSW zone on the Liddell-Muswell-Tamworth 330kV lines. These constraints largely impact on the flows on the QNI interconnector and so are discussed in more detail in Appendix C.

D.3.2 Findings from Powerlink's 2015 transmission annual planning report for Queensland

Consistent with the NTNDP for 2015, Powerlink have not identified any emerging reliability or potential economic dispatch limitations across the main transmission network linking NTNDP zones within the Queensland region. As a result, Powerlink has not identified any projects around Terranora.

D.3.3 Findings from TransGrid's 2015 New South Wales transmission annual planning report

TransGrid have identified a number of potential projects in the Northern NSW zone to address potential constraints on the transmission network in this area. Although these constraints largely impact on flows on the QNI they may also impact on the Terranora interconnector. The potential and committed projects TransGrid have identified in this region are discussed in Appendix C.

D.4 Summary of projects for identified network constraints

There are no forecast transmission network constraints on Terranora, or in the transmission corridors around Terranora in Queensland and NSW that are not being adequately addressed by the relevant TNSPs in their transmission annual planning reports. Table D.2 provides a summary of identified constraints and how these are being addressed by the relevant TNSPs.

Table D.2 Summary of identified constraints relating to the Terranora interconnector and how these are being addressed

Report limitation identified	Details of constraint identified	Project to address constraint	Project status
NTNDP for 2015 (economic constraint).	Future constraints in Northern NSW zone, in particular between Liddell and Tamworth, at times of high northward flows on the QNI interconnector. The timing of the limitation within the NTNDP forecast period is not specified. However, AEMO does not consider this limitation to be material at this stage.	Increase system capacity between Hunter Valley, Tamworth and Armidale (TransGrid).	Contingent on QNI being upgraded and new generation being connected in the Northern NSW zone. TransGrid have committed to reviewing this project at the same time as it undertakes a re-evaluation of the QNI upgrade with Powerlink (see above).

E Review of Victoria-New South Wales interconnector

> There are no transmission network constraints on the Victoria-New South Wales interconnector that are not being addressed by the relevant TNSPs in their transmission annual planning reports. Similarly, there are no network constraints in the main transmission corridors around the interconnector in Victoria and NSW 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 NSP 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 Victoria-New South Wales interconnector;
- a review of the binding constraint equations that most often set the limits on this interconnector from AEMO's NEM constraint report for 2014;
- a review of the emerging transmission network constraints affecting the interconnector from the NTNDP for 2015 published by AEMO in 2014;
- a review of TransGrid and AEMO's[58] 2015 transmission annual planning reports on projects to address constraints on the interconnector and the main transmission corridors; and
- a summary of projects planned to reduce identified transmission network constraints.

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

NSW and Victoria are interconnected via the Victoria to New South Wales interconnector.

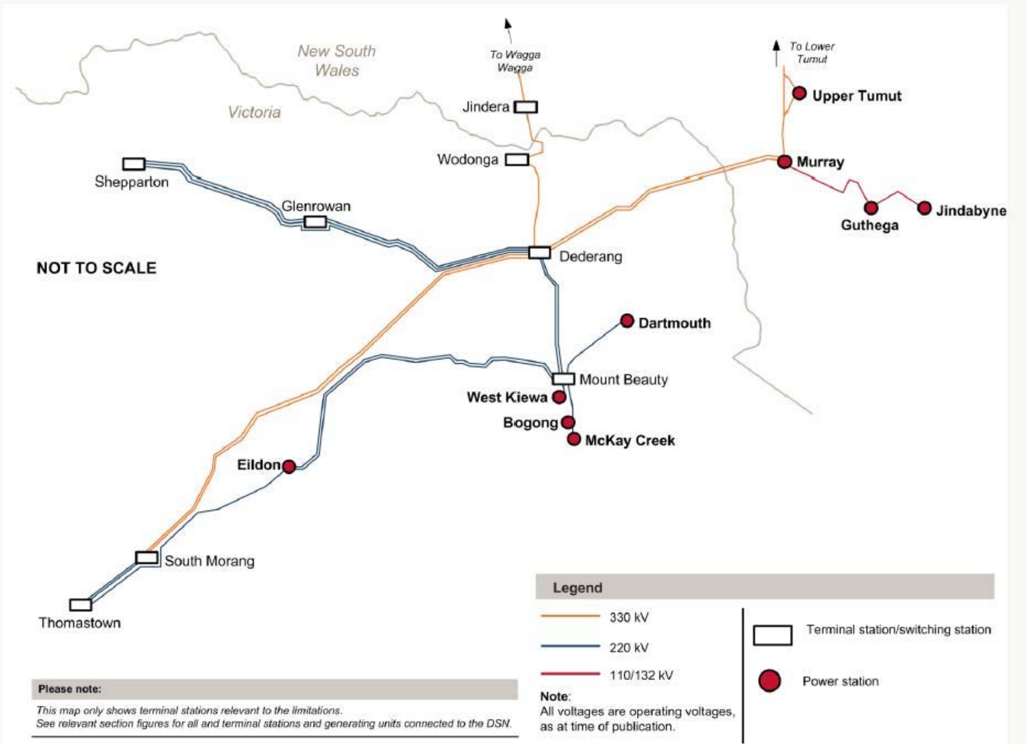
This interconnector comprises the 330 kV lines between Murray and Upper Tumut, Murray and Lower Tumut, and Jindera and Wodonga. These lines link the South West NSW zone with the Northern Victoria zone containing a large amount of hydroelectric generation. As such, they are part of the 'northern corridor' running between Murray (NSW) and South Morang (Victoria). This part of the interconnector is set out in Figure E.1

In addition, the interconnector comprises the 220 kV line between Buronga and Red Cliffs connecting Victoria's north west, part of the Country Victoria zone, to the South West NSW zone. This part of the network delivers supply to load centres in the Country Victoria zone such as Bendigo and Ballarat and also transfers power to South

58 AEMO is responsible for the planning of the network in Victoria and is a TNSP for this purpose under the NER.

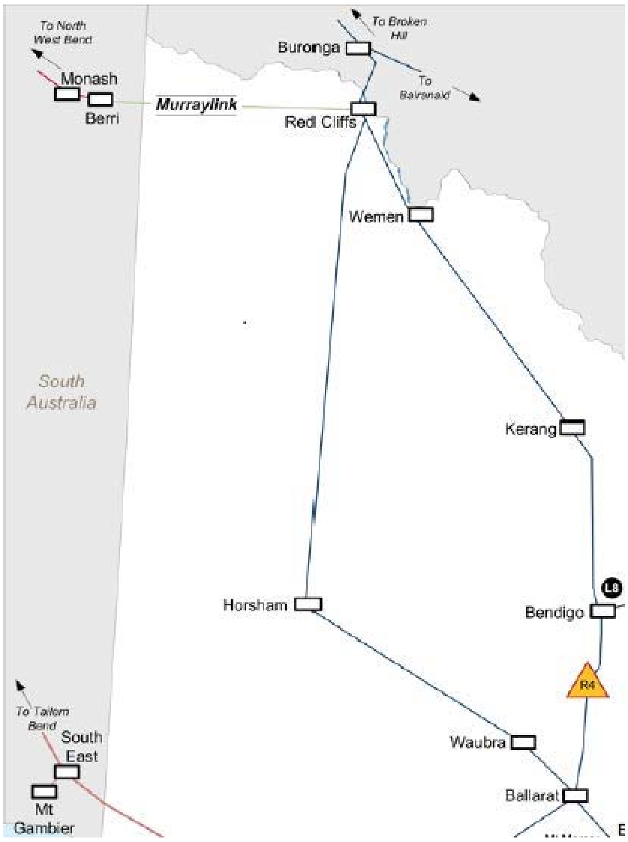
Australia via the Murraylink interconnector. This part of the indicator is set out in Figure E.2.

Figure E.1 Victoria–New South Wales interconnector



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

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



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

E.2 Findings from the NEM constraint report for 2014

The Victoria–New South Wales interconnector may bind in either direction due to high demand in NSW or Victoria.

Transfer from Victoria to NSW 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. 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.[59]

Transfer from NSW to Victoria is mainly limited by voltage collapse for loss of the largest Victorian generator or the thermal overload limits on the Murray to Denderang 330 kV lines.[60]

The top three most binding system normal constraints in both directions for 2014 that impacted on flows on the Victoria-New South Wales interconnector is listed in Table E.1.

59 AEMO, *NEM constraint report 2014*, April 2015, p23.

60 ibid. p24.

Table E.1 Binding constraint equations setting the Victoria–New South Wales interconnector limits in 2014 (system normal)

Equation ID	Hours binding in 2014	Description	Market impact (with position in top ten market impacts per region)[a]
Victoria to NSW limits			
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).	672.3	To 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.	$48,248 (does not appear in top ten constraints with a market impact in Victoria).
V::N_NILxxx (This constraint was also identified on the QLD-NSW, Heywood, Murraylink and Basslink interconnectors).	311.6	To prevent transient instability for fault and trip of a Hazlewood to South Morang 500 kV line.	$23,304 (does not appear in top ten constraints with a market impact in Victoria).
V>>SML_NIL_7A	41.6	To avoid overloading Ballarat North to Buangor 66 kV line on trip of the Ballarat to Waubra to Horsham 220 kV line.	$48,808 (does not appear in top ten constraints with a market impact in Victoria).
NSW to Victoria limits			
N^^V_NIL_1 (This constraint was also identified on the Murraylink interconnector)	207.8	To avoid voltage collapse for loss of the largest Victorian generating unit.	$701,455 (number one in top ten constraints with a market impact in NSW).
V>>V_NIL_1B (This constraint was also identified on the Murraylink interconnector).	9.3	To avoid overloading Dederang to Murray No.2 330 kV line for trip of the Dederang to Murray No.1 330 kV line.	$729,653 (number three in top ten constraints with a market impact in Victoria).

N^^V_NIL_2	4.4	To avoid voltage collapse for loss of a Dederang to Murray 330 kV line.	$38,516 (number four in top ten constraints with largest market impact in NSW)

[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 2014*, April 2015 and *NEM constraint report 2014 supplementary data*, April 2015.

E.3 Network constraints on the Victoria-New South Wales interconnector

E.3.1 Findings from the NTNDP for 2015

The NTNDP for 2015, identifies a reliability driven network constraint in the Country Victoria zone relating to the overload of the Ballarat-Bendigo 220kV circuit for an outage of the Bendigo-Shepparton 220kV circuit. It considers this constraint requires a non-network solution or an upgrade of the Ballarat-Bendigo 220kV line.[61]

The NTNDP for 2015 also identifies a potential economic constraint on the network in the Canberra zone during the outlook period to 2033-34. As a result, AEMO considers that generation in the South West NSW zone and the import of electricity to NSW from Victoria may be constrained. It considers this may occur at times of peak demand, in particular during high levels of generation in the Canberra and South West NSW zones combined with high import into NSW from Victoria. AEMO does not consider this potential constraint to be material at this stage.[62]

E.3.2 Findings from AEMO's 2015 Victorian transmission annual planning report

Deferred investment and completed projects

AEMO reports that four emerging investment opportunities identified in the 2014 Victorian annual planning report have been deferred beyond the ten year outlook due to reduced demand forecasts. One of these deferred investment opportunities was to address constraints on the Dederang–Shepparton line which services parts of regional

61 AEMO, *National Transmission Network Development Plan*, December 2015, p19. This constraint was not identified in the NTNDP for 2016 published by AEMO in November 2015 as this limitation has now been addressed.

62 AEMO, *National Transmission Network Development Plan,* December 2014, pp19-20. The NTNDP for 2016 also identifies an economic constraint in the Canberra transmission zone.

Victoria and is in the transmission corridor leading to the NSW-VIC interconnector. AEMO states that it will continue to monitor this constraint.[63]

Similarly, as a result of an update to a project assessment conclusions report of a RIT-T, AEMO reports that it sought tenders for the acquisition of non-market ancillary services in regional Victoria in July 2014 as part of a solution to manage identified constraints on the Ballarat– Bendigo 220 kV line and the Moorabool–Ballarat No.1 220 kV line.[64] After reviewing current and forecast network conditions and potential solutions, AEMO reports that it found that the acquisition of the services did not deliver net economic benefits to Victorian customers at this stage. It therefore decided to defer this expenditure.[65]

As a result of the same RIT process AEMO states that wind monitoring has been installed on the Ballarat–Bendigo 220 kV line, allowing an increase in the rating of this line. AEMO notes that this project was identified through the Regional Victorian Thermal Capacity Upgrade RIT-T process as the first stage of the preferred option.[66]

Future projects

AEMO reports that construction of an additional Moorabool to Ballarat 220 kV line will commence in early 2017.[67]

It considers that a reduction of equipment ratings increased the market impact of constraints on the Ballarat and Horsham 66kV lines during January and February 2015. These lines can limit the capability of the network to export to NSW. AEMO reports that an automatic bus-splitting control scheme at Challicum Hills 66 kV substation will be pursued to address this limitation.[68]

Finally, AEMO reports that it is monitoring network congestion relating to the South Morang 500/330 kV F2 transformer which limits the export capacity to NSW. It considers the market impact of this constraint does not currently justify augmenting the network but that it will continue to monitor the performance of this constraint and explore options to increase the export limit to NSW. It states that these options are likely to include projects to address thermal limits on the 330 kV network and transient stability limits, and are expected to primarily be contestable augmentations.[69]

63 AEMO, *Victorian annual planning report*, June 2015, p4.

64 AEMO, *Victorian annual planning report*, June 2015, p4; AEMO, *Regional Victorian Thermal Capacity Upgrade RIT-T Stage 3 Report,* 12 June 2014.

65 AEMO, *Victorian annual planning report*, June 2015, p4.

66 AEMO, *Victorian annual planning report*, June 2015, p4; AEMO, *Regional Victorian Thermal Capacity Upgrade RIT-T - Project Assessment Conclusion Report*, 10 October 2013.

67 ibid. p5.

68 ibid. p5.

69 ibid. p6.

E.3.3 Findings from TransGrid's 2015 New South Wales transmission annual planning report

TransGrid have indicated that there may be net market benefits if parts of the network between Snowy and Sydney were to be uprated. TransGrid are investigating a number of options relating to the lines between the Victoria–New South Wales interconnector and Sydney. Those potential projects relevant to the removal of network constraints on the interconnector include:

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 NSW and Queensland;
   - load growth in NSW and Queensland; and
   - decommissioning or reduction of coal-fired generation in NSW.[70]
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 NSW to the maximum capacity allowed the upgrade; and
   - the present and future wind farms connected in the Southern NSW zone operate at or near their maximum capacities.

   TransGrid notes that constraints in this part of the network would increase if other proposed generation is developed.[71]

TransGrid considers that any network development would be determined by detailed market modelling and there is no preferred network option at present.[72]

E.4 Summary of projects for identified network constraints

There are no transmission network constraints on the Victoria–New South Wales interconnector or in the transmission corridors around this interconnector that are not being addressed by the relevant TNSPs in their transmission annual planning reports.

70 TransGrid, *New South Wales transmission annual planning report*, 30 June 2015, pp97-99.

71 ibid.

72 ibid.

Table E.2 provides a summary of constraints identified in relevant planning documents that may impact flows on the Victoria-New South Wales interconnector and how these constraints are being addressed by TransGrid and AEMO.

Table E.2 Summary of transmission projects for identified network constraints impacting on the Victoria–New South Wales interconnector

Report limitation identified	Details of constraint identified	Project to address the identified need	Project status
NTNDP for 2015 (reliability driven constraint).	Reliability constraint in the Country Victoria zone which is in the transmission corridor leading to the VIC-NSW interconnector. AEMO considers this will bind between now and 2018-19.	Installation of wind monitoring on the Ballarat–Bendigo 220 kV line to increase the rating of this line.	Completed in February 2015.
NTNDP for 2015 (economic constraint).	A potential economic constraint on the network between Victoria and Sydney at times of peak demand. This may limit generation in the South West NSW zone and the import of electricity from Victoria into NSW. The timing of this limitation within the NTNDP forecast period is not specified. However, AEMO does not consider it to be material at this stage.	Projects relating to the uprating of the capacity of the transmission network between the Vic-NSW interconnector and Sydney.	TransGrid are investigating a number of options relevant to the lines between the Vic-NSW interconnector and Sydney. More detailed modelling would be required to help identify a preferred option if this was required.

F Review of the 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 TNSPs in their transmission annual planning reports. Similarly, 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 NSP under its last resort planning powers.

This section outlines the Commission's analysis including:

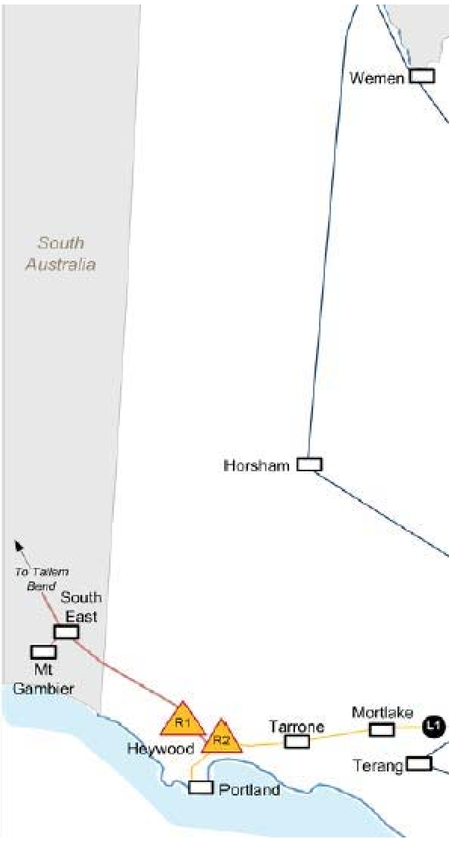
- an overview of the Heywood interconnector;
- a review of the binding constraint equations that most often set the limits on this interconnector from the NEM constraint report for 2014;
- a review of the emerging transmission network constraints affecting this interconnector from the NTNDP for 2015, published by AEMO in December 2014;
- a review of ElectraNet and AEMO's 2015 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 the Heywood interconnector

The Heywood interconnector, set out in Figure F.1, is an alternating current connection between Heywood near Portland and the South East substation in South Australia in the state's south east. 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 this zone which mainly comes from wind energy.

Figure F.1 Heywood interconnector



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

Originally, 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 MW 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, ElectraNet and AEMO have conducted a regulatory test for investment. The results of this assessment are outlined in section F.3.1.

F.2 Findings from the NEM constraint report for 2014

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.[73]

As a result of capacity increases, the voltage collapse limit for the 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, 209 in 2013 and down to 173 in 2014. Flows are now most often restricted by thermal overloads on the Snuggery to Keith 132 kV line and the Heywood 500/275 kV transformers.[74] 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.[75]

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

Table F.1 Binding constraint equations setting the Heywood interconnector limits in 2014 (system normal)

Victoria to South Australia limits			
Equation ID	**Hours binding in 2014**	**Description**	**Market impact (with position in top ten market impacts per region)[a]**
V>>S_NIL_SETB_SGKH	271.3	To 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.	$63,809 (number four in the top ten constraints with largest market impact in South Australia)
V::N_NILxxx (This constraint was also identified on the	217.7	To prevent transient instability for fault and trip of a Hazlewood to South	$23,304 (does not appear in top ten constraints with a market impact in

73 AEMO, *NEM constraint report 2014*, April 2015, p24.

74 ibid. p25.

75 ibid.

QLD-NSW, Vic-NSW, Murraylink and Basslink interconnectors).		Morang 500 kV line.	Victoria).
S>>NIL_SETB_KHTB1	192.8	To avoid overloading Keith - Tailem Bend #1 132kV on trip of South East - Tailem Bend 275kV line.	$166,195 (number three in the top ten constraints with largest market impact in South Australia)
South Australia to Victoria limits			
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).	616.5	To 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.	$48,248 (does not appear in top ten constraints with a market impact in Victoria)
S>>V_NIL_SETX_SETX	406.2	To 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.	$291,351 (number two in the top ten constraints with largest market impact in South Australia)
S>V_NIL_HYTX_HYTX	0.7	To avoid overloading a Heywood 275/500 kV transformer on trip of the other Heywood 275/500 kV transformer.	$55 (does not appear in top ten constraints with a market impact in either Victoria or South 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 2014*, April 2015 and *NEM constraint report 2014 supplementary data*, April 2015.

F.3 Network constraints on the Heywood interconnector

F.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 possible economic benefits 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-scale 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 RIT-T process in January 2013. Subsequently, ElectraNet submitted a request to the Australian Energy Regulator in April 2013 for a determination on whether the preferred option satisfied the RIT-T.[76]

The Australian Energy Regulator found that the option identified by ElectraNet and AEMO in their report provides the maximum economic benefits, and satisfies the requirements of the RIT-T. The upgrade would increase the capability of the network to transfer electricity between the two regions. The Australian Energy Regulator 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.[77]

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76 NER clause 5.16.6 allows a RIT-T proponent to request the AER to determine whether a preferred option satisfies the RIT-T. ElectraNet's request is published on the Australian Energy Regulator's website: www.aer.gov.au.

77 Australian Energy Regulator, *Decision: South Australia – Victoria (Heywood) interconnector upgrade*, September 2013.

In March 2014, the AER adjusted ElectraNet's maximum allowed revenue for the 2013-14 to 2017-18 regulatory period to allow it to recover the efficient costs of upgrading the interconnector. The upgrade of the interconnector was determined to be a contingent project by the AER in ElectraNet's 2013-14 to 2017-18 revenue determination, as the project was not certain to proceed at that time.[78] This was consistent with what ElectraNet proposed during the revenue determination process.

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; and
- 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.

The project is due to be completed in July 2016.[79]

F.3.2 Findings from the NTNDP for 2015

The NTNDP for 2015 identified the potential for economic constraints on the Heywood interconnector between the South East substation and Heywood. This was forecast at times of peak demand in South Australia leading to high import from Victoria to South Austraia or high levels of South Australia export to Victoria during times of high wind generation in South Australia.[80]

In addition, the NTNDP for 2015 also identified four network constraints on the ElectraNet network in South Australia as potential market benefit constraints. Of these constraints, one relates to the South Australian transmission corridor leading up to the Heywood interconnector, that of the Tailem Bend–Tungkillo transmission corridor.

78 Australian, Energy Regulator, *Final decision: ElectraNet transmission determination 2013-14 to 2017-18*, April 2013, p44.

79 ElectraNet, *South Australian transmission annual planning report*, May 2015, pp76-79.

80 AEMO, *National Transmission Network Development Plan*, 17 December 2014, p20. The NTNDP for 2016 published by AEMO in November 2015 does not identify this constraint.

AEMO considers this constraint may occur due to new generation it forecasts east of Adelaide or at times of high import from Victoria.[81]

AEMO did not identify any constraints within the Victorian transmission corridor leading up to the Heywood interconnector in the NTNDP for 2015. It noted the Heywood interconnector upgrade as a committed project in information accompanying this NTNDP.[82]

F.3.3 Findings from the AEMO's 2015 Victorian transmission annual planning report

Consistent with forecasts in the NTNDP for 2015, AEMO did not identify any projects in the transmission corridors in Victoria around the Heywood interconnector. It notes the Heywood interconnector upgrade as a committed project.[83]

F.3.4 Findings from ElectraNet's 2015 transmission annual planning report

ElectraNet noted in its 2015 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. They will also occur between Tailem Bend and Heywood on the 275 kV network.[84]

ElectraNet reports that while early indications, as reported in 2014, suggested that forecast higher gas prices could make a further interconnector upgrade economic, more detailed investigation has shown this not to be the case at this time. It notes that it is exploring lower cost opportunities to improve equipment ratings that would help to minimise the identified constraints. It will also continue to monitor the drivers of congestion to identify the appropriate time for a further upgrade of the interconnector.[85]

As part of its planning process ElectraNet also considered three scenarios:

- a base scenario which was ElectraNet's central planning scenario (the base scenario);
- a scenario which considers a number of potential future mining loads (the SA mining growth scenario); and

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81 AEMO, *National Transmission Network Development Plan*, December 2014, p20. The NTNDP for 2016 also identifies this constraint.

82 AEMO, *Annual planning reports project summary*, 17 December 2014.

83 AEMO, *Victorian annual planning report*, June 2015, p5.

84 ibid. p58.

85 ibid. pp58-59.

- a scenario that represents an extreme yet possible future expansion of SA wind generation (the SA renewable generation expansion planning scenario).[86]

ElectraNet identified some potential augmentation projects that would avoid significant congestion at peak demand times on the SA transmission network if implemented within the next ten years under the SA renewable generation expansion scenario.[87] One of the potential projects would incrementally increase available export transfers across the Heywood interconnector. The project is to apply dynamic line ratings to the Tungkillo to Heywood 275 kV corridor. ElectraNet notes that this project is subject to the demonstration of net market benefit following further wind farm connections.[88] ElectraNet notes that a more significant increase in the ability to export power from South Australia would be contingent on the ability of a new interconnector to provide net market benefits.[89]

F.4 Summary of projects for identified network constraints

There are no 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 TNSPs in their transmission annual planning reports. Table F.2 provides a summary of identified constraints relating to the Heywood interconnector and how these constraints are being addressed by AEMO and ElectraNet in their transmission annual planning reports.

86 ibid. pp80-81.

87 ibid. p92.

88 ibid. pp92-94.

89 ibid. p92.

Table F.2 Identified constraints relating to the Heywood interconnector and projects addressing these

Report limitation identified	Details of constraint	Project addressing constraint	Project status
NTNDPs for 2014 and 2015.	Limitations on the Heywood interconnector between the South East substation and Heywood.	Heywood interconnector upgrade.	Completion anticipated in July 2016.
NTNDP for 2015 (potential economic dispatch limitation)	Reduce congestion on Tailem Bend–Tungkillo 275 kV line due to new generation east of Adelaide or high import from Victoria. AEMO does not specify the timing of this constraint within the NTNDP outlook period. However, it does not consider it to be material at this stage.	ElectraNet considers that a further upgrading of the interconnector is not efficient at this time. ElectraNet is exploring lower cost opportunities to improve equipment ratings that would help to minimise the identified constraints.	Ongoing consideration.

G Review of Murraylink interconnector

> There are no transmission network constraints on the Murraylink interconnector that are not being addressed by the relevant TNSPs in their annual planning reports. Similarly, 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 NSP under its last resort planning powers.

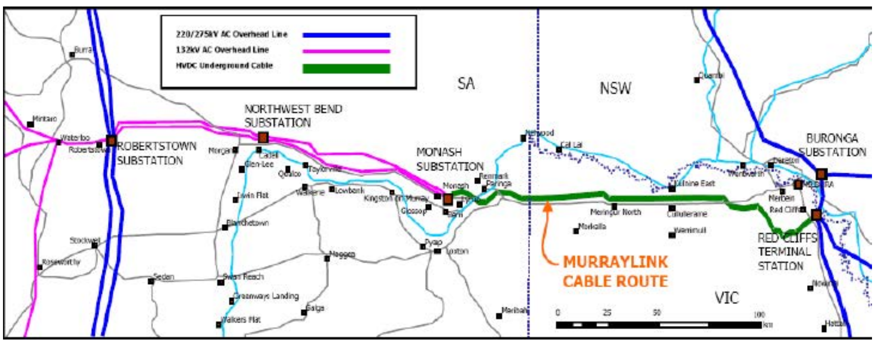
This section outlines the Commission's analysis in support of this conclusion. This analysis includes:

- an overview of the Murraylink interconnector;
- a review of the binding constraint equations that most often set the limits on this interconnector from the NEM constraint report for 2014 published by AEMO;
- a review of the emerging transmission network constraints affecting this interconnector from the NTNDP for 2015, published by AEMO in 2014;
- a review of ElectraNet and AEMO's 2015 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 Murraylink interconnector

Murraylink is a 220 MW direct current link between Red Cliffs in Victoria and the Monash substation near Berri in South Australia as set out in Figure G.1. It was commissioned in 2002 and is owned by Energy Infrastructure Investments Pty Ltd.

Figure G.1 Murraylink interconnector



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

The interconnector connects the County Victoria zone with the North South Australia zone. The wider Country Victoria zone includes load centres such as Geelong and

Ballarat, and it links to the Melbourne and Northern Victoria zones. 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.

G.2 Findings from the NEM constraint report for 2014

Many of the thermal issues closer to Murraylink are handled by the South Australian or Victorian Murraylink runback schemes.[90] 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.[91]

Transfers from Victoria to South Australia on Murraylink are mainly limited by thermal overloads on the South Morang F2 transformer, South Morang–Denderang 330 kV line, Ballarat–Bendigo 220 kV line, or Ballarat North to Buangor 66kV line. Alternatively these flows may be limited by the voltage collapse limit for loss of the Darlington Point–Buronga (x5) 220 kV line for an outage of the NSW Murraylink runback scheme.[92] 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.[93]

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

90 These schemes allow higher pre-contingency flows on Murraylink due to automatic post-contingency action returning the network to a secure state.

91 AEMO, *NEM constraint report 2014*, April 2015, p26.

92 ibid.

93 ibid.

Table G.1 Binding constraint equations setting the Murraylink limits in 2014

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 (This constraint was also identified on the Victoria–New South Wales, Heywood and Basslink interconnectors).	662.4	To 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.	$48,248 (does not appear in top ten constraints with a market impact in Victoria).
V::N_NILxxx (This constraint was also identified on the QLD-NSW, Vic-NSW, Heywood, and Basslink interconnectors).	310.9	To prevent transient instability for fault and trip of a Hazlewood to South Morang 500 kV line.	$23,304 (does not appear in top ten constraints with a market impact in Victoria).
N^^V_NIL_1 (This constraint was also identified on the Victoria-NSW interconnector).	105.0	To avoid voltage collapse for loss of the largest Victorian generating unit.	$701,455 (number one in top ten constraints with largest market impact in NSW).
South Australia to Victoria limits			
S>V_NIL_NIL_RBNW	235.3	To avoid overloading the North West Bend to Robertstown 132 kV line on no line trips. AEMO notes that this constraint normally sets the upper limit on Murraylink.	$2,478,435 (number one in top ten constraints with largest market impact in South Australia).
S>>V_NIL_RBTX_MW4RB	133.4	To avoid overloading Morgan Whyalla 4 to Robertstown line on	$11,477 (not in top ten constraints with largest market

		trip of one Robertstown 275/132kV transformer, feedback.	impact in South Australia or Victoria).
V>>V_NIL_1B (This constraint was also identified on the Vic-NSW interconnector).	8.5	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 NSW to Victoria with the DBUSS (Dederang bus splitting scheme) active.	$729,653 (number three in top ten constraints with largest market impact in Victoria).

[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 2014*, April 2015 and *NEM constraint report 2014 supplementary data*, April 2015.

G.3 Network constraints on the Murraylink interconnector

G.3.1 Findings from the NTNDP for 2015

The NTNDP for 2015 did not find the need for upgrade of the Murraylink interconnector transfer capability under its modelling assumptions.

In relation to the main transmission corridors in South Australia, the NTNDP for 2015 identified a limitation on the Robertstown–North West Bend 132 kV line as a reliability driven network limitation. AEMO considers this limitation could occur during times of peak load conditions in the Riverland area when Murraylink is not importing into South Australia. It predicts it will bind between now and 2018-19.[94]

Similarly, AEMO identified potential economic constraints during the NTNDP outlook period on the 132kV transmission network in the Riverland area of South Australia. It considers this constraint may bind during high levels of wind generation in the North South Australia zone.[95] Details and results of ElectraNet and AEMO's joint planning studies related to the Riverland region of South Australia are summarised below.

94 AEMO, *National Transmission Network Development Plan*, December 2014, p20. The NTNDP for 2016, published in November 2015, does not identify this constraint as it has now been addressed.

95 ibid. The NTNDP for 2016 also identifies this constraint.

Regarding connections to neighbouring zones in Victoria, the NTNDP for 2015 identified a reliability driven network constraint in the Country Victoria zone relating to the overload of the Ballarat-Bendigo 220kV circuit for an outage of the Bendigo-Shepparton 220kV circuit. It considers this constraint requires a non-network solution or an upgrade of the Ballarat-Bendigo 220kV line.[96] This constraint is discussed in relation to the NSW-Vic interconnector in section E.3.

G.3.2 Findings from AEMO's 2015 Victorian transmission annual planning report

There were no specific projects in the AEMO's Victorian transmission annual planning report that specifically related to the transmission corridors leading to the Murraylink interconnector. However, there were some projects in the Country Victoria zone that were discussed in the context of the Vic-NSW interconnector in Appendix E which are also relevant to the Murraylink interconnector.

G.3.3 Findings from ElectraNet's 2015 South Australian transmission annual planning report

To provide increased transfer capacity into the Riverland region, ElectraNet and AEMO considered a range of augmentations through a joint planning process. The recommendations were 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;
- increase line clearance on the Robertstown–North West Bend No. 1 132 kV line to improve the summer thermal rating in 2015; and
- monitor the ability of Murraylink to provide capacity support for the Riverland region in future years.[97]

ElectraNet noted that these recommendations are consistent with the NTNDP for 2015 which identified transfer constraints on the Robertstown–North West Bend 132 kV line and advised of the potential need for additional capacity along the Riverland region 132 kV transmission corridor.[98]

ElectraNet reports that the outcomes of this study have been incorporated into its network development plans and that the capital works relating to these projects have been committed to and are due to be completed by summer 2015/2016.[99]

96 AEMO, *National Transmission Network Development Plan*, December 2015, p19. The NTNDP for 2016 does not identify this constraint as it has now been addressed.

97 Electranet, South Australian transmission annual planning report, May 2015, p59.

98 ibid.

99 ibid. p59.

As noted in section F.3 of this report, as part of its planning process ElectraNet also considered three scenarios:

- a base scenario which was ElectraNet's central planning scenario (the base scenario);
- a scenario which considers a number of potential future mining loads (the SA mining growth scenario); and
- a scenario that represents an extreme yet possible future expansion of SA wind generation (the SA renewable generation expansion planning scenario). The assumptions in this scenario included: reductions in connection point and system wide maximum demand forecasts from the base scenario; maintaining the existing conventional generation fleet; and 1.86 GW of new wind generation over the next ten years.[100]

ElectraNet identified some potential augmentation projects that would avoid significant congestion at peak demand times on the SA transmission network if implemented within the next ten years under the SA renewable generation expansion scenario.[101] One of these projects would involve the installation of up to two 15 MVAr 132 kV capacitors at Monash which would improve voltage levels on the Riverland 132 kV network during times of high power transfer through the Riverland, area. ElectraNet considers this would support increased available exports across the Murraylink interconnector.[102]

G.4 Summary of projects for identified network constraints

There are no 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 TNSPs in their transmission annual planning reports. Table G.2 provides a summary of the projects impacting on the Murraylink interconnector that are noted in relevant planning documents and how these constraints are being addressed in AEMO and ElectraNet's 2015 transmission annual planning reports.

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100 ibid. pp80-81.

101 ibid. p92.

102 ibid. p95.

Table G.2 Identified constraints relating to the Murraylink interconnector and how these are being addressed

Report limitation identified	Constraint details	Project to address constraint	Project status
NTNDP for 2015 (reliability driven and potential economic network constraint).	Overload of Robertson–North West Bend line during times of peak load conditions in the Riverland area when Murraylink is not importing into South Australia. AEMO predicts that this constraint will bind between now and 2018-19. Constraints in the Riverland area as a result of high levels of wind generation in the North South Australia zone	Implement dynamic ratings on the Robertstown–North West Bend No. 1 132 kV line and on the Robertstown–MWP3 132 kV line section. Increase line clearance on the Robertstown–North West Bend No. 1 132 kV line to improve the summer thermal rating in 2015.	Completed. Due to be completed in November 2015.
NTNDP for 2015 (potential economic dispatch limitation).	Reduce transmission network constraints in the Riverland area as a result of high levels of wind generation in the North South Australia zone. AEMO does not specify the timing of this constraint within the outlook period. However, it does not consider this constraint to be material at this stage.	Monitor ability of Murraylink to provide capacity support for the Riverland region in future years.	Ongoing.

H Review of Basslink interconnector

There are no transmission network constraints on the Basslink interconnector that are not being addressed by the relevant TNSPs in their annual planning reports. In addition, 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 NSP under its last resort planning powers.

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

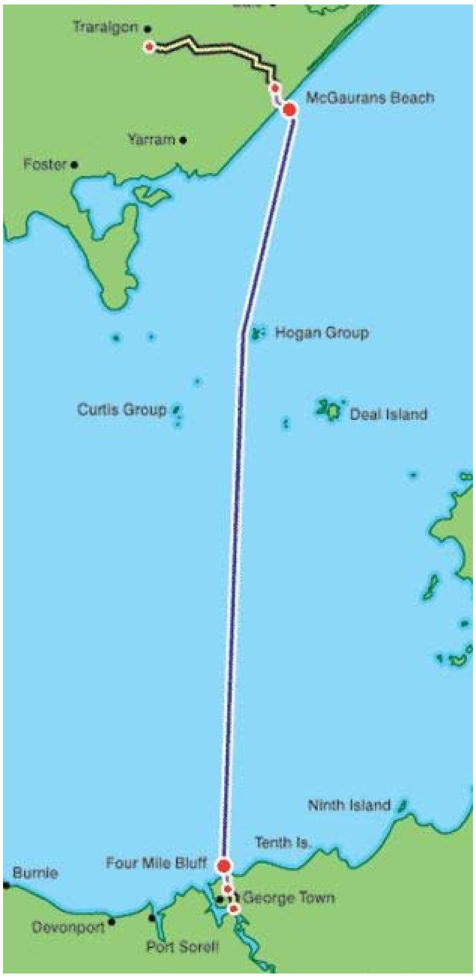
- an overview of the Basslink interconnector;
- a review of the binding constraint equations that most often set the limits on this interconnector from AEMO's NEM constraint report for 2014;
- a review of the emerging transmission network constraints affecting this interconnector from the NTNDP for 2015, published in December 2014;
- a review of TasNetworks' and AEMO's 2015 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.

H.1 Overview of Basslink interconnector

Victoria and Tasmania are connected via the Basslink interconnector. Basslink is a direct current interconnection between George Town in Tasmania and Loy Yang in the Latrobe Valley area in Victoria as set out in Figure H.1. It is an unregulated market link that was commissioned in early 2006 after Tasmania joined the NEM. Basslink is owned by Keppel Infrastructure Trust.[103] Unlike the other direct current lines in the NEM, Basslink has a frequency controller and is able to transfer frequency control ancillary services between Tasmania and the mainland.

103 Keppel Infrastructure was known as CitySpring Infrastructure until 18 May 2015.

Figure H.1 Basslink interconnector



Source: Basslink website, www.basslink.com.au, viewed 9 November 2015.

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. The Tasmanian region has a significant amount of hydroelectric generation. This generation is geographically dispersed across the region.

As Basslink is an unregulated market interconnector and not a TNSP, it is not required to apply the RIT-T to address an identified investment need on the interconnector. Therefore, if the Commission identified a deficiency in the planning arrangements of the interconnector it would not be able to direct Basslink to carry out a RIT-T 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 could direct the TNSP in Victoria, Tasmania or both to undertake a RIT-T.

H.2 Findings from the NEM constraint report for 2014

AEMO reports that the majority of constraints on Basslink transfers are due to frequency control ancillary service constraint equations for both mainland and Tasmanian contingency events.

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.[104]

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

Table H.1 Binding constraint equations setting the Basslink limits in 2014 (system normal)

Tasmania to Victoria limits			
Equation ID	**Hours binding in 2014**	**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).	644.8	To 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.	$48,248 (does not appear in top ten constraints with a market impact in Victoria)
T^V_NIL_BL_6	50.8	To prevent transient over-voltage at Georgetown 220 kV bus for loss of Basslink.	$8,967 (number ten in top ten constraints with a market impact in Tasmania)
T^V_NIL_8	35.8	Tamar Valley Combined Cycle GT OOS, prevent voltage collapse at Georgetown 220 kV	$11,988 (number nine in top ten constraints with a market impact in Tasmania)

104 Source: AEMO, *NEM constraint report 2014*, April 2015 and *NEM constraint report 2014 supplementary data*, April 2015, p27.

		bus for loss of a Sheffield to George Town 220 kV line, swamped if Tamar Valley Combined Cycle in service.	
Victoria to Tasmania limits			
V_T_NIL_FCSPS	267.0	Basslink limit from Victoria to Tasmania for load enabled for the Basslink frequency control special protection scheme (FCSPS)	$59,536 (does not appear in top ten constraints with a market impact in either Victoria or Tasmania)
V::N_NILxxx (This constraint was also identified on the QLD-NSW, Vic-NSW, Heywood and Murraylink interconnectors).	112.0	To prevent transient instability for fault and trip of a Hazlewood to South Morang 500 kV line.	$23,304 (does not appear in top ten constraints with a market impact in Victoria)
V_T_NIL_BL1	100.8	Basslink no go zone limits Victoria to Tasmania.	$29,369 (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 2014*, April 2015 and *NEM constraint report 2014 supplementary data*, April 2015.

H.3 Network constraints on the Basslink interconnector

H.3.1 Findings from the NTNDP for 2015

AEMO did not identify any forecast network constraints for Basslink in the NTNDP for 2015 during the outlook period to 2033-34.

However, it identified two potential economic dispatch constraints in Tasmania. In particular it considered there could be constraints in the Burnie to Sheffield or Palmerston to Sheffield transmission corridors at times of high wind generation in Tasmania.[105]

105 AEMO, *National Transmission Network Development Plan*, December 2014, p20. The NTNDP for 2016 also identifies these constraints.

The NTNDP for 2015 did not identify any transmission network constraints in the eastern corridor in the Latrobe Valley and into Greater Melbourne over the outlook period.

H.3.2 Findings from AEMO's 2015 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 2015 transmission annual planning report.

AEMO reports that some emerging investment opportunities identified in the 2014 Victorian transmission annual planning report have been deferred beyond the ten year outlook due to reduced demand forecasts. This included projects to relieve constraints on the Rowville-Malvern lines, the Rowville-Springvale-Heatherton lines, and the Rowville A1 500/220 kV transformer.[106] These lines are part of the Eastern transmission corridor between Melbourne and the La Trobe Valley.

H.3.3 Findings from TasNetworks' 2015 Tasmanian transmission annual planning report

TasNetworks states that as a result of the softening demand forecast, the majority of its projects have been deferred, a number to outside its ten year planning horizon.

However, it noted the installation of line fault location functionality on the Sheffield to Palmerston and Sheffield to Burnie 220kV transmission lines which will help reduce the time taken to locate faults, allowing quicker restoration times. It states that this project is scheduled to be completed in June 2016.[107]

H.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 TNSP in their transmission annual planning reports. Table H.2 provides a summary of the constraints impacting on the Basslink interconnector that are noted in the NTNDP for 2015 and how these are being addressed in AEMO and Transend's transmission annual planning reports where relevant.

106 AEMO, *Victorian annual planning report*, June 2015, p4.

107 TasNetworks, *TasNetworks annual planning report 2015*, June 2015.

Table H.2 Summary of constraints relating to the Basslink interconnector and how these are being addressed by the relevant TNSP

Report limitation identified	Details of constraint identified	Project to address constraint	Project status
NTNDP for 2015 (potential economic dispatch limitation).	Transmission network constraints in the Burnie–Sheffield transmission corridor as a result of high levels of new generation in North-West Tasmania. AEMO does not specify the expected timing of the constraint during the outlook period. However, it does not consider this potential constraint to be material at this stage.	No commentary in annual planning report. TasNetworks has not proposed investment be undertaken in ten year outlook period.	Investment not required at this stage.
NTNDP for 2015 (potential economic dispatch limitation).	Reduce transmission network constraints in the Palmerston–Sheffield transmission corridor as a result of high levels of new generation in Central Tasmania. AEMO does not specify the expected timing of the constraint during the outlook period. However, it does not consider this potential constraint to be material at this stage.	No commentary in annual planning report. TasNetworks has not proposed investment be undertaken in ten year outlook period.	Investment not required at this stage.