Australian Energy Market Commission

DECISION REPORT

Last Resort Planning Power - 2013 Review

5 December 2013

REVIEW

Reference: EPR0037
Decision report

Inquiries

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

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

Reference: EPR0037

Citation

AEMC 2013, Last Resort Planning Power - 2013 Review, decision report, 5 December 2013, Sydney

About the AEMC

The Council of Australian Governments (COAG), through its then Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. In June 2011, COAG established the Standing Council on Energy and Resources (SCER) to replace the MCE. The AEMC has two main functions. We make and amend the national electricity, gas and energy retail rules, and we conduct independent reviews of the energy markets for the SCER.

Executive summary

This report contains the Australian Energy Market Commission's (AEMC or Commission) decision regarding the exercise of the last resort planning power in 2013.

The purpose of the last resort planning power is to ensure timely and efficient inter-regional transmission investment for the long term interests of consumers of electricity. To that end, the AEMC assesses whether constraints in respect of critical inter-regional transmission flow paths in the National Electricity Market (NEM) are being sufficiently addressed in the planning activities of the jurisdictional planning bodies in the NEM.

If the Commission considers this is not the case, it has the power to direct participants to undertake additional planning activities.

From analysis undertaken, it appears jurisdictional planning bodies are including inter-regional transmission priorities in their planning activities. The Commission therefore concludes that there is no need to exercise the last resort planning power in 2013.

Background

The interconnected transmission network is important for facilitating a secure and stable supply of electricity to consumers and supporting the NEM wholesale market. It contributes to the National Electricity Objective of efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers.

Timely identification of constraints that may impact on the inter-regional transmission capability of the network is therefore crucial. An important aspect of transmission planning is to examine potential constraints in the transmission network and to consider options for alleviating those constraints when it is economically efficient to do so.

Responsibility for transmission planning in the NEM is shared between the Australian Energy Market Operator (AEMO) in its role as National Transmission Planner and jurisdictional planning bodies for each region of the NEM. AEMO annually publishes the National Transmission Network Development Plan (NTNDP), which identifies NEM-wide transmission planning priorities that are relevant for the development of the national transmission flow paths in the NEM. Jurisdictional planning bodies are required to take the most recent NTNDP into account when conducting their annual planning reviews.

2012 Review

In order to assess the need for exercising the last resort planning power in 2013, the Commission has reviewed the planning documents of the jurisdictional planning bodies for each region of the NEM in light of planning priorities identified in the 2012 NTNDP.

Substantial changes in the market environment, most notably the decline in energy demand growth, have led AEMO to conclude in the 2012 NTNDP that less transmission investment is likely to be required over the 25 year outlook period compared to previous estimates. Similarly, the NTNDP modelling found less need for augmentations to interconnectors. An exception is the upgrade of the Heywood interconnector between Victoria and South Australia. The planning bodies for Victoria and South Australia are actively addressing this upgrade. The Australian Energy Regulator recently found that the proposed upgrade of this interconnector satisfied the regulatory investment test for transmission.

From analysis undertaken, it appears jurisdictional planning bodies are including the inter-regional transmission priorities as identified in the 2012 NTNDP in their planning activities.

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

The review thus did not find a lack of planning activity regarding inter-regional transmission infrastructure. The Commission therefore concludes that there is no need to exercise the last resort planning power in 2013.

Last resort planning power

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

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

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

Contents

1 Introduction

Role of transmission network

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

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

The interconnected transmission network therefore contributes to the National Electricity Objective (NEO) of efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers.

Bottlenecks on the transmission network ('constraints') can impact on the network's ability to transfer electricity, including between regions. This can limit the benefits of interconnection and can create risks for generators and retailers, which will be discussed in more detail in the next chapter.

Transmission planning

Transmission planning relates to a suite of processes that are undertaken with a view to making decisions about the development of the transmission network. An important aspect of transmission planning is to examine constraints in the transmission network that may impact on the free flow of electricity across that network, and to consider options for alleviating those constraints where it is economically efficient to do so.

Planning processes range from long-term, NEM-wide planning to shorter-term regional planning to investment decision making and actual project implementation (see further chapter 3). Responsibilities for long-term and short-term transmission planning activities are shared between the Australian Energy Market Operator (AEMO) and transmission network service providers (TNSPs) in their role as jurisdictional planning bodies (JPBs) for respective regions of the NEM.

The National Electricity Rules (NER) also provide for a 'last resort planning power' (LRPP), conferred on the Australian Energy Market Commission (AEMC or Commission). The purpose of the LRPP is for the AEMC to assess whether sufficient consideration has been given to inter-regional transmission constraints in the planning activities of the TNSPs. If the Commission considers this is not the case, it has the power to direct participants to undertake additional planning activities (see further section 3.2).

The NER require the Commission to report annually on the exercise of the LRPP. This report fulfils that obligation.

Structure of this document

This report is structured as follows:

- Chapter 2 provides a background to the role of interconnectors and the existence of network constraints that impact on interconnector flows;
- Chapter 3 describes the transmission planning framework in the NEM and the role of the LRPP;
- Chapter 4 provides a summary of the 2011 and 2012 National Transmission Network Development Plans and inter-regional planning priorities identified by AEMO, as well as the main interconnector constraints in 2012;
- Chapters 5-9 compare the planning priorities impacting on inter-regional electricity flows as identified by the JPBs with priorities identified by AEMO; and
- Chapter 10 then considers, on the basis of the analysis undertaken in the previous chapters, whether there is reason for the Commission to exercise the LRPP in 2013.

2 Interconnection and constraints

2.1 Interconnection

Almost 40,000 km of transmission lines and associated infrastructure make up the physically interconnected NEM transmission network. The network supplies approximately 200,000 gigawatt hours of energy to both business and households from Far North Queensland to Tasmania each year.

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:[1]

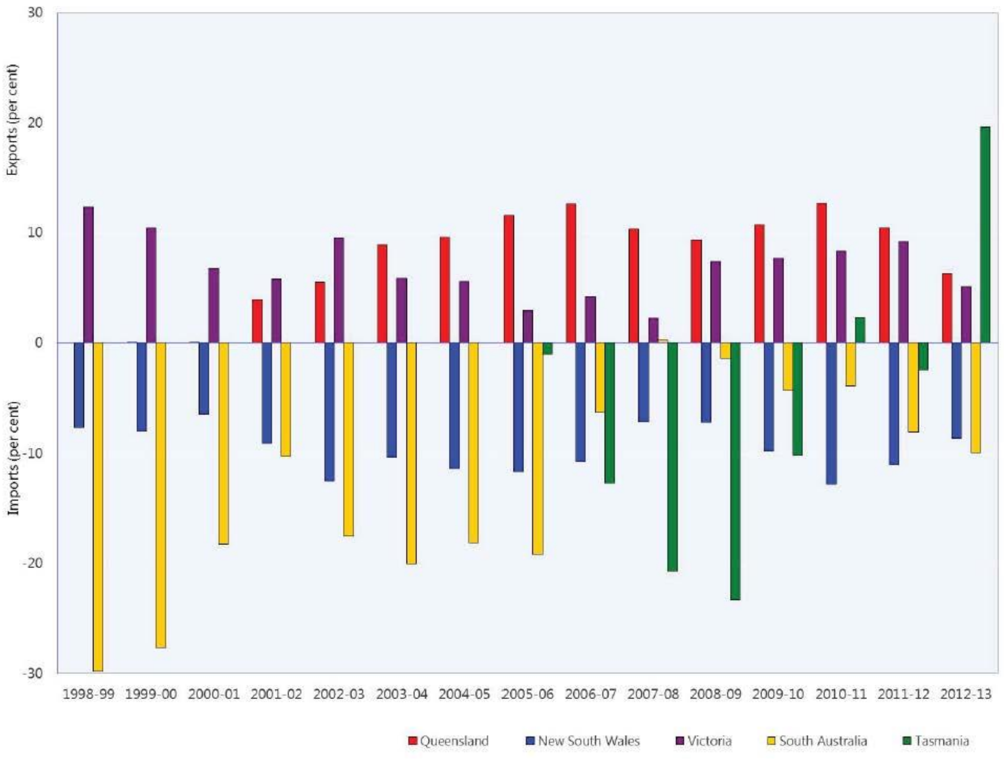
- allows electricity in lower priced regions to flow to higher priced regions, thereby reducing the cost of meeting demand in the NEM and the degree of price separation between regions;
- can contribute to a reduction of price volatility in regions;
- enables retailers to access cheaper sources of generation,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

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

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

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

Figure 2.1 Inter-regional trade, in net flows, as a percentage of regional demand



Taken from: AER, website, industry statistics. accessed via: http://www.aer.gov.au/Industry-information/industry-statistics

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

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

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

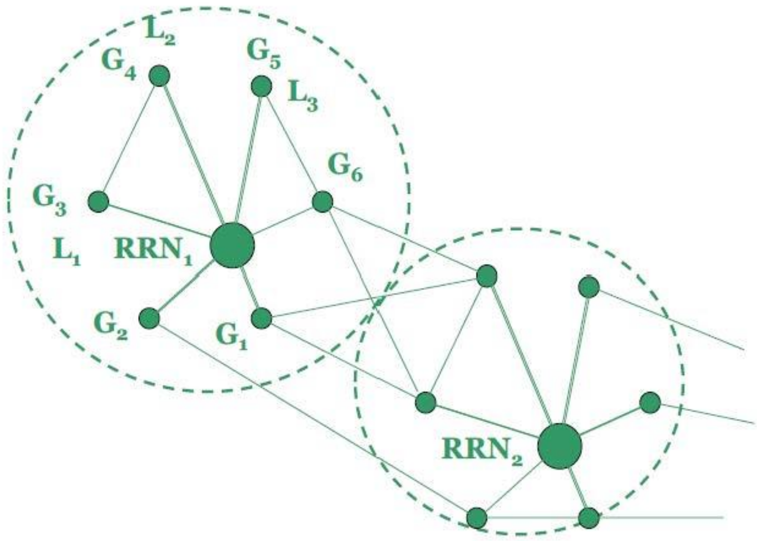
The TNSPs operate the transmission networks in the five regions of the NEM and are responsible for ensuring a reliable supply of electricity over the transmission system to consumers in their respective regions.

TNSPs need to comply with transmission reliability and system security requirements which guide how they plan and operate their networks.

2.2 Interconnectors

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

Figure 2.2 Stylised representation of interconnectors as cross-border infrastructure

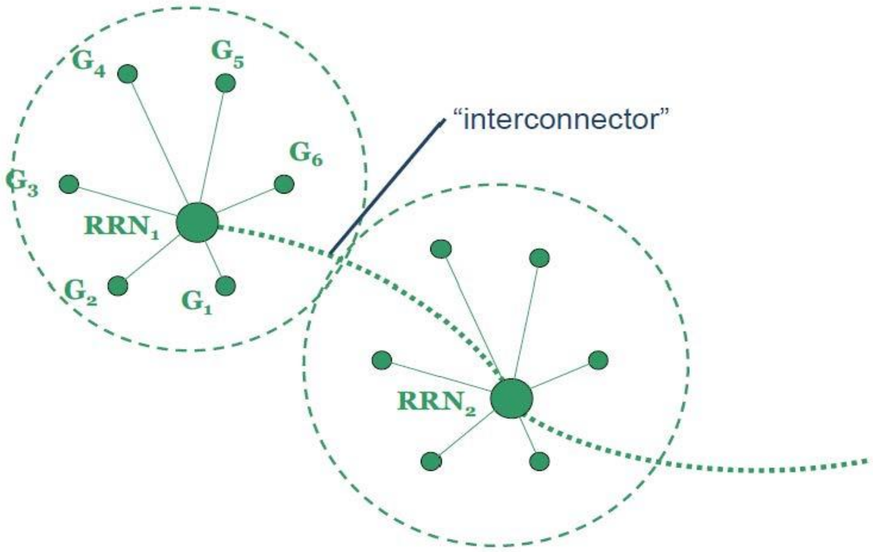


'RRN' refers to regional reference node; 'G' to generator and 'L' to load (demand) centres.

Taken from: 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 reference nodes in different regions of the NEM, as illustrated by figure 2.2. In this sense, they are a mathematical representation of the movement of electricity from one regional reference node to another.

Figure 2.3 Treatment of interconnectors for market purposes



Taken from: *AEMO, Electricity network regulation - AEMO's response to the Productivity Commission Issues Paper*, 21 May 2012, p31.

There are two types of interconnectors in the NEM: regulated and unregulated (merchant) interconnectors.[2]

A regulated interconnector is an interconnector that forms part of a TNSP's regulated assets.[3] TNSPs that own these interconnectors receive a regulated annual revenue based on the value of the asset, set by the Australian Energy Regulator (AER), regardless of the actual usage. The revenue is collected as part of the network charges included in the bills of electricity end-users.

The operator of a merchant interconnector derives revenue from the price difference on the wholesale market between a lower and a higher priced region. Alternatively, it could sell the rights to this revenue.[4]

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 (see next section) 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 2.1.

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

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

4 Unregulated interconnectors are not required to undergo the Regulatory Investment Test for Transmission.

Table 2.1 Interconnectors in the NEM

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

Interconnector capacity limits taken from: AEMO, *Interconnector performance*; Quarter June-August 2013, 10 October 2013.

This figure illustrates where the interconnectors are physically located:

Figure 2.4 Location of interconnectors in the NEM

AEMO, *An introduction to the Australia's National Electricity Market*, July 2010.

AEMO publishes details on the performance of interconnectors on a quarterly basis, which assists in scheduling and dispatch functions.[5]

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

2.3 Network constraints

The ability of the network to carry electricity (the 'transfer capability') is in practice affected by a range of factors.[6]

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

Importantly 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 via the first element.

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

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

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 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.

2.4 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

---

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

thermal, voltage and stability limits of the network. Within these parameters, NEMDE calculates the optimal market solution for dispatch (ie the lowest cost solution for dispatch of generation in order to meet demand).

Network limitations 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 2.1: 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 dispatch of the generator (G) and interconnector (IC) cannot exceed 500 MW. The α and β represent the coefficients 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 for example 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 - ie AEMO cannot dispatch the lowest priced generation because of network constraints - a constraint is said to be 'binding'.

Information about constraints feeds into the planning process, as planning bodies will need to assess costs and benefits of addressing constraints. Constraints can essentially be addressed in two ways:

- by augmentations to the transmission infrastructure ('network options');[7]and
- via solutions such as demand-side management and network support control ancillary services[8], which may reduce strains on transmission infrastructure elements during certain periods, thereby assisting in keeping the usage of this infrastructure within its physical limits ('non-network options').

2.5 The effect of network constraints

Constraints in the network due to network congestion or outages could undo the benefits of interconnection that were mentioned earlier.

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 dispatch of higher-priced generation than would have been the case without the constraint.

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

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

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

considerations of net costs and benefits. In other words, some level of congestion is likely to be economically efficient.[9]

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

Box 2.2: Congestion and inter-regional settlement residues

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 they are based. 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. 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 accrue to AEMO via the NEM settlement process. AEMO then auctions off these residues among interested NEM participants.

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 settlement residues can be negative. The cost of funding these negative settlement residues is ultimately borne by consumers in the importing region.[10]

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

10 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 amount payable to TNSPs. TNSPs then recover these expenses through higher network service fees.

3 Transmission planning in the NEM and the last resort planning power

3.1 Transmission planning in the NEM

Transmission infrastructure is expensive to build, due to potentially large distances and resulting high capital costs. Investment decisions therefore need to be carefully assessed as costs will ultimately be borne by consumers.[11] Decisions about augmenting the transmission network also need to be taken in a timely manner, in order to reduce the risk of future transmission network limitations.

Not all network constraints will have the same market impact. Costs and benefits associated with augmenting the transmission infrastructure therefore need to be weighed, in order to focus on alleviating those constraints which have a significant market impact (ie the costs of network investment are likely to be outweighed by the market benefit of alleviating the constraint).

Transmission planning relates to a range of processes that are undertaken with a view to making decisions about the development of the transmission network, so that augmentations take place in a cost-effective and timely manner.

At a high level, roles and responsibilities in connection with transmission planning include:[12]

- planning: long-term and short-term;
- project specific planning/investment decision; and
- implementation of investment.

Long-term and short term planning

Long-term, strategic planning is undertaken by AEMO as National Transmission Planner. In this capacity, AEMO must annually publish the National Transmission Network Development Plan (NTNDP).[13]

The NTNDP provides a strategic vision for the development of the NEM transmission network as a whole, in particular the major inter-regional transmission flow paths (ie those areas of the transmission network connecting major generation or demand centres). Its overall objective is to facilitate the development of an efficient national electricity network that considers potential transmission and generation investments.[14] The minimum planning period for the NTNDP is 20 years.

Developing this long-term plan involves a number of activities, including the development of the different scenarios to be used for planning purposes. These

11 Costs are recouped via the network charges included in the bills of electricity end-users. In its *Economic regulation of network service providers* rule change, the AEMC made a number of amendments to the NER to improve the strength and capacity of the AER to determine network revenues.

12 NERA and Allens Linklaters, *Alternative Transmission Planning Arrangements: Ensuring Nationally Coordinated Decision-making - A Report prepared for the AEMC*, May 2012, p3.

13 NEL, s49(2); NER, rule 5.20.2.

14 AEMO, NTNDP 2012, p1-1.

scenarios can cover a range of different economic and government policy assumptions, demand forecasts and also generation scenarios.

In addition to the NTNDP, AEMO publishes a number of documents which inform and assist in the planning process. Among these documents are:

- the National Electricity Forecast Report, which provides annual energy and maximum demand forecasts over the next 10 years for each of the five regions in the NEM;
- the Electricity Statement of Opportunities (ESOO), which provides an assessment of supply adequacy in the NEM over the next 10 years, highlighting opportunities for generation and demand-side investment. The ESOO is complemented by the Power System Adequacy report, which assesses the electricity supply outlook for the next two years; and
- the NEM Constraint Report, which contains details on constraints in the transmission network.

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

The NER require that there is a JPB for each NEM jurisdiction. A JPB is defined as 'the entity nominated by the relevant Minister of a participating jurisdiction as having transmission system planning responsibility in that participating jurisdiction'.[15] With the exception of Victoria, where AEMO has been nominated as JPB, the TNSPs are responsible for transmission planning activities within their respective regions.

Table 3.1 Overview jurisdictional planning bodies

NEM region	Jurisdictional Planning Body
Queensland	Powerlink
New South Wales (and ACT)[16]	TransGrid
Victoria	AEMO
South Australia	ElectraNet
Tasmania	Transend

The NER prescribe that each TNSP must undertake an annual planning review. The purpose of this review is for a TNSP to analyse the expected future operation of its transmission network, taking account of forecast future demand and generation, demand side and transmission developments and other relevant data, and to consider

15 NER, Chapter 10, Glossary.

16 For transmission planning purposes, the ACT is part of the NSW region of the NEM.

the potential for network augmentations or non-network alternatives to augmentations. The minimum planning period for the purposes of this review is ten years.[17]

The results of the annual planning review must be published in an Annual Planning Report (APR), which describe the network developments plans for each of the individual state transmission networks. The APRs must be published before 1 July each year.

TNSPs are required to take the most recent NTNDP into account when conducting their annual planning review. When a TNSP proposes certain augmentations to the network, it must explain how the proposed augmentations relate to the most recent NTNDP and the development strategies for current or potential national transmission flow paths that are specified in that NTNDP.[18]

This framework seeks to ensure coordination between the planning priorities identified in NTNDP regarding inter-regional flow paths and the planning activities undertaken by the JPBs in the individual jurisdictions. In addition to inter-regional flow paths, the TNSPs will typically also consider upgrades that primarily affect transmission flow paths within their regions (ie intra-regional).

The long-term and short-term planning undertaken by AEMO and the TNSPs is complemented with the last resort planning power, conferred on the AEMC (see section 3.2).

Project specific planning/investment decision

Project specific planning relates to a particular investment need and culminates in a particular investment decision. The NER require that TNSPs must apply a Regulatory Investment Test for Transmission (RIT-T) to proposed transmission investments projects with an estimated cost of more than $5 million.

The purpose of a RIT-T is to identify the transmission investment option that maximises the net economic benefit to all those who produce, consume and transport electricity in the market, after having performed cost-benefit analysis of a number of credible options.[19] The NER define a 'credible option' as an option or group of options that:

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

The costs associated with options for transmission augmentation must be weighed against the benefits they are likely to bring to the market. Under the current RIT-T, investments may be undertaken to either meet reliability standards, or to deliver a net market benefit (ie economic expansion).

The NER require the RIT-T proponent to consider a number of classes of market benefits that could be delivered by each credible option, such as:

---

17 NER, clause 5.12.1. In Victoria, AEMO undertakes this review in its role as JPB.

18 NER, clause 5.12.2(c)(6).

19 NER, clause 5.16.1

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes costs for parties, other than the RIT-T 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 services costs; and
- competition benefits.

The NER also set out the procedure which a RIT-T proponent must follow for a proposed transmission network.

Following the RIT-T evaluation, the investment decision is made - ie a decision as to which investment will be undertaken.

Implementation of investment

The actual implementation of the investment follows on from the investment decision. It involves a number of detailed activities in order to construct and then commission the asset, such as:[20]

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

3.2 The last resort planning power

The last resort planning power was added to the NER in response to a concern that there may be insufficient incentives on AEMO and the JPBs to adequately consider inter-regional network developments.[21]

Clause 5.22(b) of the NER states that the purpose of the LRPP is

> "(...) to ensure timely and efficient inter-regional transmission investment for the long term interests of consumers of electricity."

20 NERA and Allens Linklaters, *Alternative Transmission Planning Arrangements: Ensuring Nationally Coordinated Decision-making - A Report prepared for the AEMC*, May 2012, p6.

21 AEMC 2007, *National Electricity Amendment (Transmission Last Resort Planning) Rule 2007*, Rule Determination, 8 March 2007

Under the LRPP, the AEMC has the power to direct a participant to undertake a RIT-T if the Commission considers there has been insufficient consideration of an inter-regional transmission constraint in the planning activities of a JPB. Specifically, the NER provide that the Commission may direct one or more Registered Participants:[22]

> "(1) to identify a potential transmission project and apply the regulatory investment test for transmission to that project; or
>
> (2) to apply the regulatory investment test for transmission to a potential transmission project identified by the AEMC. "[23]

Under the LRPP, the Commission would not direct that a certain investment occurs, but that the RIT-T is applied to a project which would address an identified inter-regional transmission constraint. The NER state that, in the course of deciding whether or not to exercise the LRPP, the AEMC must:

> "(1) identify a problem relating to constraints in respect of national transmission flow paths between regional reference nodes or a potential transmission project (the problem or the project);
>
> (2) make reasonable inquiries to satisfy itself that there are no current processes underway for the application of the regulatory investment test for transmission in relation to the problem or the project;
>
> (3) consider whether there are other options, strategies or solutions to address the problem or the project, and must be satisfied that all such other options are unlikely to address the problem or the project in a timely manner;
>
> (4) be satisfied that the problem or the project may have a significant impact on the efficient operation of the market; and
>
> (5) be satisfied that but for the AEMC exercising the last resort planning power, the problem or the project is unlikely to be addressed. "[24]

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

The NER require the Commission to report annually on the exercise of the LRPP.[25] In the past three years that the Commission has conducted this review, we have not found the need to exercise the last resort planning power.

22 A 'Registered Participant' is a person who is registered by AEMO in any one or more of the categories listed in rules 2.2 to 2.7 and includes network service providers and generators.

23 NER, clause 5.22(c).

24 NER, clause 5.22(g).

25 NER, clause 5.22(m).

3.3 The Commission's approach to exercise of the LRPP

Taking the NER requirements into account, the Commission has adopted a three-stage approach to the LRPP.

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

- the NTNDP of the current and previous year (as required by the NER);
- the NEM Constraint Report 2012;
- the APRs 2013; and
- any other relevant document, such as RIT-T documentation.

The second stage of the process would only be undertaken if the first stage identifies a constraint on an inter-regional flow path that may not have been adequately examined by the relevant JPBs. This second stage would focus on the particular flow path identified. The goal would be to collect all the information for a more in depth assessment of the identified potential planning gap. During the second stage of the LRPP assessment the AEMC would request information from AEMO and the relevant JPBs using the process laid out by the *LRPP Guidelines 2010*.[26] The AEMC would use this information to more closely examine this inter-regional flow path and the estimated economic impacts of the constraint. If the Commission was to conclude that making a direction may meet the National Electricity Objective, it would initiate the third stage.

At the third stage of the process the AEMC would request submissions from stakeholders. These submissions would be used to determine what information would need to be included in any direction that would be made to either the relevant JPBs or another registered participant. The third stage assessment of the LRPP would also focus on who should be directed to undertake the RIT-T and potential solutions that could be examined.

26 The *Last Resort Planning Power Guidelines* were published in December 2010, and are available via the AEMC website: www.aemc.gov.au.

4 Review of 2011 and 2012 NTNDPs

The NER require the AEMC to review the NTNDP for the current and previous year when considering the exercise of the LRPP. This chapter therefore provides a summary of the 2011 and 2012 NTNDPs and their key findings, in particular where they relate to inter-regional transmission priorities.

As was mentioned earlier, the NTNDP is typically concerned with development of the critical national transmission flow paths - ie those areas of the transmission network connecting major generation or demand centres.

The NTNDP seeks to influence transmission investment by:[27]

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

For NTNDP planning purposes the transmission network has been split into sixteen zones, referred to as 'transmission zones'. These zones capture differences in generation technology capabilities (eg wind capacity) and differences in costs (eg caused by the differences in connection costs) that exist within each NEM region.[28]

This figure provides an overview of these zones, and the flow paths between the zones:

27 Ibid, p1-1.

28 See: AEMO, *2012 Modelling methodology and assumptions*, 30 January 2012, p7.

Figure 4.1 National transmission zones and flow paths

Zone abbreviations

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

Taken from: Transend, *Annual Planning report for Tasmania*, 2013, p28.

4.1 The 2011 National Transmission Network Development Plan

The 2011 NTNDP built on the 2010 NTNDP in that no new modelling was undertaken compared to the 2010 NTNDP. The 2010 NTNDP presented five long-term, strategic scenarios, and, for each of these scenarios, two carbon price scenarios, giving a total of 10 different scenarios. These scenarios subsequently formed the potential drivers for modelling of transmission congestion and upgrade solutions. Other differences between the scenarios relate to, for example, economic and population growth, and the way in which generation investment will be affected (eg in the form of larger, centralised power stations, or smaller, distributed generation located closer to demand centres).

Table 4.1 provides an overview of the different scenarios and their inputs regarding key drivers.

Table 4.1 Scenarios 2010 NTNDP

Scenario	Economic growth	Population growth	Global carbon policy	Centralised supply-side response	Decentra-lised supply-side response	Demand-side response	Emission targets below 2000 levels
Fast rate of change	high	high	strong	strong	strong	strong	-25%[3] (sensitivity -15%)
Uncertain world	high	high	weak	strong	weak	weak	-5% [1] (sensitivity no carbon price)
Decentralised world	medium	medium	strong	weak	strong	strong	-15%[2] (sensitivity -25%)
Oil shock and adaptation	low	medium	moderate	moderate (renewable)	weak	weak	-15%[2] (sensitivity -5%)
Slow rate of change	low (mixed)	low	weak	moderate	weak	weak	-5%[1] (sensitivity no carbon price)

1. The -5% carbon emissions target (low carbon price) is associated with a carbon price trajectory from AUD0 to AUD44 per tonne CO2e.

2. The -15% carbon emissions target (medium carbon price) is associated with a carbon price trajectory from AUD0 to AUD62 per tonne CO2e.

3. The -25% carbon emissions target (high carbon price) is associated with a carbon price trajectory from AUD0 to AUD93 per tonne CO2e.

Taken from: AEMO, 2010 NTNDP, Executive Briefing.

In preparing the 2011 NTNDP, AEMO considered that the 2010 planning scenarios remained valid because, while there were small movements in demand forecasts from 2012, demand levels and project timings remained consistent with the 2010 scenarios.

On the basis of these scenarios, the 2010 and 2011 NTNDPs concluded that between $4 billion and $9 billion of transmission augmentation investment would be required over the next 20 years across the NEM. This investment is required to support new generation asset investments of between $35 billion under a low carbon price, low economic demand scenario, and $120 billion under a high carbon price, high economic growth scenario.

The 2010 and 2011 reports included a number of recommendations regarding interconnector upgrades. These are listed in the table 4.2, with the classification of 'urgency' given by AEMO.

Table 4.2 Interconnector recommendations 2010 and 2011 NTNDPs

Interconnector	Transmission development	Urgency rating
QNI	Series compensation on Armidale-Dumaresq 330 kV circuits and Dumaresq-Bulli Creek 330 kV circuits.	Early attention[29]
Vic to NSW	Upgrade of interconnector capacity between Victoria and New South Wales	Preparatory work[30]
Vic to NSW	A new 220 kV, 250 MVA phase angle regulator on the 220 kV Buronga-Red Cliffs interconnection to maintain a 200 MW export capability from VIC to SA on the Murraylink interconnector.	Early attention
Vic to SA	Work on the Heywood interconnector.	None given, but the RIT-T process regarding the Heywood upgrade, undertaken by ElectraNet and AEMO, is noted (see section 7.1.1 below)

In addition, the 2010 and 2011 NTNDPs listed a number of intra-regional transmission upgrades in regions of the NEM requiring attention if interconnector upgrades were realised, resulting in increased electricity flows across certain parts of the network.

4.2 The 2012 National Transmission Network Development Plan

4.2.1 Introduction

The 2012 NTNDP provides a new strategic 25-year plan for the NEM transmission network, thereby replacing the 2010 and 2011 plans. Substantial changes in the market environment, which impact on the input conditions to the NTNDP, are the reason for this.[31]

An important change in the market environment has been the decline in energy demand growth, with expected future growth rates expectations being revised downwards compared to previous years. Maximum demand growth is also growing less quickly.[32]

The slower energy demand is in itself driven by a number of developments. These include changes in the economic outlook, an increase in the installation of rooftop solar photovoltaic installations, which reduce energy taken from the power system, and changes in customer behaviour in response to electricity price increases. Significant

29 Development is triggered in the first five-year period under most scenarios and in the second five-year period in most of the remaining ones.

30 Development is generally triggered in the second five-year period in most scenarios but maybe later in others.

31 AEMO, 2012 NTNDP, Introduction, p1-1.

32 Ibid, p1-2.

price increases have also driven scrutiny of network investment and how further price increases can be contained by improving the efficiency of investment.[33]

These changing market circumstances are reflected in the 2012 NTNDP. The 2012 NTNDP provides AEMO's view of how the NEM's generation and transmission might be most efficiently developed in view of the current and expected market environment.

4.2.2 Modelling inputs and assumptions

This section summarises the modelling methodology and assumptions applied for the 2012 NTNDP, which have been subject to consultation by AEMO with market participants and other interested stakeholders.

For the 2012 NTNDP, AEMO selected two scenarios for detailed modelling:

- a Planning scenario, which represents AEMO's best estimate of how the future will develop; and
- a Slow Rate of Change scenario, which describes a future characterised by lower economic growth, low commodity prices, and a carbon price that dips effectively to zero after an initial three-year fixed-price period. The Slow Rate of Change scenario was modelled to investigate the sensitivity of the results to carbon price and demand growth assumptions.[34]

Both scenarios seek to describe the Australian stationary energy sector in 25 years' time. They differ regarding some of the key inputs in the scenario. Table 4.3 provides an overview:

33 Ibid.

34 AEMO, 2012 NTNDP, section 5.1.

Table 4.3 Planning scenarios 2012 NTNDP

Scenario	Economic				Greenhouse			
	Economic growth	Commodity prices	Productivity growth	Population growth	Reduction target (below 2000 levels)	Carbon price	National renewable energy target scheme	Green power sales
Planning	National economic growth continues at currently predicted levels. Global recovery continues with ongoing growth in the demand for Australian commodities particularly resources.	medium	medium	medium	5% reduction by 2020, 80% reduction by 2050.	Treasury core scenario, starting at 23 $/t CO2-e on 1 July 2012.	LRET[35] remains in place to 2036–37 with no significant changes from the two-yearly reviews. SRES[36] remains in place to 2030 with currently announced reductions to the STC[37] multiplier.[38]	No growth
Slow rate of change	Lower	low	low	low	Zero reduction by 2020, 80% reduction by 2050.	Treasury core scenario for first three years, then 0 $/t CO2-e.	Remains in place (as Planning scenario).	No growth

AEMO, *2012 NTNDP*, p5-3.

The scenarios were subsequently used as input for AEMO's modelling of generation development. AEMO refers to this as 'least cost expansion plan' modelling.

AEMO's modelling considers new generation developments, inter-regional transmission network augmentations and generation retirements across the NEM and seeks to deliver an optimal mix (ie which minimises overall capital and operating costs) of these elements under the scenario inputs.[39]

This optimisation is subject to:

- ensuring supply matches demand for electricity at any time (ie meeting reliability standards);
- ensuring sufficient generation is built to meet peak demand with the largest generation unit out of service ('N-1'); and

---

35 Large-scale Renewable Energy Target

36 Small-scale Renewable Energy Scheme.

37 Small-scale Technology Certificates

38 Also referred to as the Federal Solar Credits rebate Renewable Energy Certificate (REC) (STC) multiplier

39 See: AEMO, *2012 Modelling methodology and assumptions*, 30 January 2012.

- meeting the LRET which mandates an annual level of generation to be sourced from renewable energy sources.[40]

In AEMO's modelling, the transmission network is represented by a simplified, five-node model, representing the five regions of the NEM, joined together by interconnectors. Hence, it does not model intra-regional network elements.[41]

Because the model does not have information about intra-regional network elements, AEMO tested the generation expansion results by undertaking transmission network power flow studies. For example, it could be the case that the input fixed and variable costs for new generation are low in a particular zone. AEMO's model may locate a large concentration of new capacity at that zone. However, this may only be viable with substantial intra-regional network upgrades. If these costs had been taken into account in the new entry decision, perhaps the expansion model may have chosen a different location or more distributed new generation. AEMO feeds information from the transmission network flow studies into its modelled expansion plan in order to refine the results.[42]

AEMO's transmission development analysis focuses on assessing the adequacy of the main transmission network to reliably support major power transfers between NEM generation and demand centres, and identifying potential network needs when there is insufficient transmission network capability. This analysis is based on the assumption that new generation development follows AEMO's modelled expansion plan.

AEMO considered a list of possible inter-regional upgrade options when conducting their expansion modelling. An option was selected if the additional inter-regional transfer capability results in a net benefit, ie the costs of the upgrade are outweighed by lower total system costs.

4.2.3 Key findings

This section summarises the key findings of the 2012 NTNDP, particularly regarding transmission investment needs. More detailed findings for the regions are included in chapters 5-9.

On the basis of changes in the input conditions, most notably less demand, the 2012 NTNDP modelling found that less transmission investment is likely to be required over the 25 year outlook period compared to previous estimates. This has resulted in a revised transmission investment estimate of $4 bn compared to the previously estimated $7 bn.

The NTNDP modelling found that most main transmission network limitations are due to demand growth in major demand centres (eg around Melbourne). Some limitations are also driven by changed power flow patterns, resulting for example from increased use of renewable generation which is often located in more remote areas. The NTNDP observes that renewable generation is primarily driven by the LRET until 2020, with

40 Ibid, p6.

41 Ibid, p7.

42 Ibid, p14.

wind generation being the main technology until 2020. Other technologies, like solar and biomass, begin to appear towards 2020.

AEMO notes that, under their modelling, demand growth in each NTNDP zone is largely met by new generation in the same zone. AEMO therefore concludes there is generally sufficient capability in the main transmission network to allow for growth and avoiding the need for significant new transmission investment.

Regarding inter-regional transmission infrastructure, the NTNDP notes that, after the Heywood interconnector upgrade (see also section 7.1.1 below), further upgrades involving individual interconnector augmentations are not required because of low projected demand growth. Due to interconnector costs being expected to outweigh the market benefits from increased power transfer capabilities between regions, no need for further increases in power transfer capability between regions emerges for the outlook period.

Of the interconnector projects listed in the 2010-2011 NTNDPs, only the augmentations to the Heywood interconnector are therefore listed as a priority in the 2012 NTNDP.

AEMO, however, also notes that the transmission network adequacy assessments do not capture all variables that may influence transmission planning decisions. AEMO's assessment of transmission network adequacy for example does not include the following:[43]

- transmission augmentations that may be required if future generation development does not follow AEMO's modelled expansion plan;
- intra-regional transmission augmentations driven by economic justification to deliver net market benefits (for example, to improve competition);
- transmission augmentations based on TNSPs applying different planning criteria;
- ongoing local transmission needs in each transmission zone; and
- the need for additional transmission to replace aged assets.

Some of these aspects follow from the division of planning responsibilities in the NEM, as mentioned earlier, between AEMO as National Transmission Planner and TNSPs as planning bodies for individual states. The latter will, for example, have additional regard to local transmission needs within their regions when making transmission planning decisions.

This also leaves open the possibility that certain transmission infrastructure investments, which may be subject to planning activity undertaken by TNSPs, may meet an economic benefit test such as the RIT-T even if they do not appear in AEMO's modelling.

4.3 NEM Constraint Report 2012

AEMO also annually publishes the *NEM Constraint Report*. The report contains details about constraint equation performance in the preceding calendar year, drivers of

43 AEMO, 2012 NTNDP, p3-2.

constraint equation changes, analysis of binding and violating constraint equations, market impact of constraint equations and constraint equations that set interconnector limits. As the report is published after publication of the NTNDP, jurisdictional planning bodies have had the ability to use or consider this information to inform their annual planning reports.

From the Constraint Report, it can be deducted that the following 'system normal'[44] constraints formed the top five 'most binding' constraints (in terms of number of hours) on interconnector limits in 2012.

Table 4.4 Top five most binding constraints on interconnector limits by number of hours

Equation ID	Interconnector	Hours binding in 2012 (in 2011)	Description
S>>V_NIL_SETX_SETX	South Australia - Victoria	422.3 (195.3)	System normal constraint to avoid overloading a South East 275/132 kV transformer on trip of the remaining South East 275/132 kV transformer.
V::N_NILxxx	Victoria - New South Wales	364.0 (994.2)	System normal constraint to avoid transient instability for fault and trip of a Hazelwood to South Morang 500 kV line. There are 12 constraint equations that make up the transient stability export limit from Victoria and all the binding results have been combined.
V::N_NILxxx	Victoria - New South Wales	348.9 (864.5)	System normal constraint to avoid transient instability for fault and trip of a Hazelwood to South Morang 500 kV line. There are 12 constraint equations that make up the transient stability export limit from Victoria and all the binding results have been combined.
SVML_000	South Australia - Victoria (Murraylink)	281.6 (67.4)	South Australia to Victoria on Murraylink upper transfer limit of 0 MW
Q>>NIL_855_871	Queensland - New South Wales (QNI)	276.2 (215.6)	System normal constraint, in order to avoid overload on Calvale to Wurdong (871) 275 kV line on trip of Calvale to Stanwell (855) 275 kV line. AEMO notes that this constraint equation is expected to bind for a similar amount in 2013 until Powerlink constructs double circuit 275kV lines between Calvale and Stanwell , expected in late 2013.

Constraints can also be listed according to their market impact. The market impact seeks to quantify - in dollar value - the impact of a particular constraint.[45] This is not a definitive number - it gives an indication of the relative value of a certain constraint.

44 System normal constraints do not include constraints caused by outages or FCAS requirements.

From the information presented in the NEM Constraint Report, the following top five 'system normal' constraints on interconnector limits by market impact can be summarised:

Table 4.5 Top five most binding constraints on interconnector limits by market impact

Equation ID	Interconnector	Market impact 2012 (in 2011)	Description
Q>>NIL_855_871	Queensland - New South Wales (QNI)	$1,431,065 ($74,016)	System normal constraints to avoid overload on Calvale to Wurdong (871) 275 kV line on trip of Calvale to Stanwell (855) 275 kV line.
Q>>NIL_871_855	Queensland - New South Wales (QNI)	$895,184 ($20,711)	System normal constraints to avoid overload on Calvale to Stanwell (855) 275 kV line on trip of Calvale to Wurdong (871) 275 kV line.
V>>V_NIL_1B	Victoria - New South Wales	$199,598 ($36,520)	System normal constraint to avoid overloading Dederang to Murray #2 330 kV line for trip of the Dederang to Murray #1 330 kV line. AEMO notes that this constraint equation binds for high transfers from NSW to Victoria with the DBUSS (Dederang bus splitting scheme) active.
S>>V_NIL_RBTXW_RBTX1	South Australia - Victoria	$158,347 ($17,083)	System normal constraints to avoid overloading Robertstown #1 275/132 kV transformer on trip of the Robertstown #2 275/132 kV transformer. AEMO notes that this constraint equation normally binds when there is high generation from Northern, Hallett GT and the wind farms connected to the 275 kV between Robertstown and Davenport.
S>>V_NIL_SETX_SETX	South Australia - Victoria	$156,867 ($76,861)	System normal constraint to avoid overloading a South East 275/132 kV transformer on trip of the remaining South East 275/132 kV transformer.

As is obvious from the above, the number of hours a constraint may occur does not necessarily correlate with its market impact. For example, while the S>>V_NIL_SETX_SETX constraint may have been binding for the highest number of hours, it did not have the largest market impact.

45 The market impact is calculated by adding up the marginal values from the marginal constraint cost re-rerun. 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 then added up.

5 Review of inter-regional planning priorities Queensland - New South Wales

The next chapters review inter-regional planning priorities identified by AEMO in the 2012 NTNDP for the respective regions of the NEM, and the planning activities described by the jurisdictional planning bodies in their APRs. The purpose is to examine whether planning priorities relating to inter-regional transmission constraints as identified in the NTNDP are being addressed by the JPBs. Planning priorities can relate to upgrades of actual interconnector capacity or to augmentations to infrastructure further removed from the interconnectors, which impact on inter-regional flows via the interconnectors.

The chapters also contain information on the constraints that were most binding on the interconnector limits in 2012 and review whether these constraints are being addressed by the JPBs.

This chapter focusses on inter-regional planning priorities for the Queensland - New South Wales interconnection.

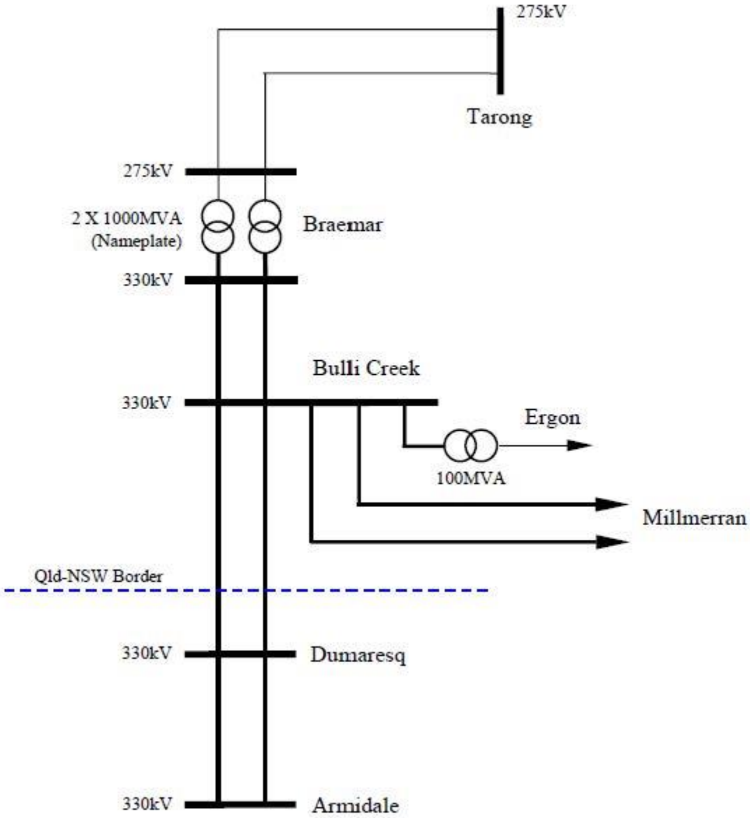
Queensland and New South Wales are interconnected via the Queensland–New South Wales interconnector (QNI) and the Terranora (Directlink) interconnector.

5.1 Queensland - New South Wales interconnector (QNI)

5.1.1 Introduction QNI

The QNI is the interconnection which connects the South West Queensland zone with the North New South Wales zone. It runs between Bulli Creek in Queensland and Dumaresq in New South Wales. Schematically, QNI can be illustrated as follows:

Figure 5.1 Queensland - New South Wales interconnector



Taken from: Powerlink and TransGrid, *Benefits of upgrading the capacity of the QNI*, March 2004.

The South West Queensland zone has the highest installed capacity in the Queensland region, with 4,790 MW of coal generation capacity. There is currently no installed wind generation capacity, and in the NTNDP modelling no wind generation is established in the outlook period.[46] The generation capacity exceeds local demand, so the region is a net exporter of electricity.

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

The flow on the QNI is normally from Queensland into New South Wales. However, at times of high generation in New South Wales or low generation in Queensland the flow can reverse and go from New South Wales to Queensland. Due to their close electrical proximity on the New South Wales side, both QNI and Terranora often appear on the LHS of constraint equations.[47]

46 AEMO, 2012 NTNDP, p3-7.

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

5.1.2 2012 NTNDP findings

This section summarises findings in the 2012 NTNDP regarding potential augmentations to interconnector transfer capacity, as well as potential augmentations to other transmission network infrastructure that impact on power flows across the interconnector.

Augmentations to the QNI

The 2012 NTNDP considered various augmentations to upgrade the power transfer capability of the QNI, by assessing the net market benefits under AEMO's modelled expansion plan. These options are driven by the ability for New South Wales to export energy to Queensland during high demand periods (given Queensland has the highest energy and demand growth among the regions), while allowing Queensland to export energy to New South Wales during lower demand periods.[48]

The NTNDP modelling does not find the need for any QNI interconnector upgrade options under the Planning scenario within the outlook period. Under these assumptions, the need for increased power transfer capability between Queensland and New South Wales does not arise because the augmentation cost outweighs the market benefits.

AEMO, however, also notes that if generation development in South West Queensland differs from the patterns AEMO modelled, future transmission reinforcement may be required to address any thermal, voltage stability and transient stability limitations. For example, if 1,200 MW of new generation currently modelled in South East Queensland zone (which has major demand centres in Brisbane and the Gold Coast) is located in the South West Queensland zone, then depending on the location and amount of new generation, increased power transfers from South West Queensland to South East Queensland will reach the existing limits, requiring reinforcement of the transmission network within South West Queensland and between the zones.[49]

Augmentations to Queensland infrastructure

The NTNDP notes that there are no limitations involving the main transmission network in or between any of the Queensland zones under AEMO's modelled expansion plan. This assessment builds on already committed projects by Powerlink.

One of these projects concerns the Calvale to Stanwell line. In practice, electricity flows on the QNI can be constrained by thermal limits on the Calvale to Wurdong and Calvale to Stanwell lines (see also information from the NEM Constraint report below).

The NTNDP notes that Powerlink has committed to building a new 275 kV double circuit line between Calvale and Stanwell to alleviate this constraint.[50]

48 Ibid, p3-6.

49 Ibid.

50 Ibid, p3-4.

Augmentations to New South Wales infrastructure

The transmission needs identified in the NTNDP build on major transmission network projects that TransGrid is already undertaking. Among these are:

- installation of a power oscillation damper on the Armidale static VAR compensator (SVC)[51] to increase the QNI interconnector's power transfer capability in the Queensland to New South Wales direction (under the RIT-T as part of the QNI upgrade project); and
- a new 200 MVAr capacitor[52] at the Armidale Substation to increase the QNI interconnector's power transfer capability in the New South Wales to Queensland direction (already committed to).

In addition, the NTNDP mentions that some limitations may occur as demand in the North New South Wales zone grows. The North New South Wales transmission network comprises multiple flow paths where 132 kV lines operate in parallel to 330 kV lines. As a result, 330 kV network power flows, including the QNI interconnector, can be limited by the 132 kV network's capability. As demand in the North New South Wales zone grows and as 132 kV network limitations increase, the NTNDP considers that strengthening or removing some of the 132 kV networks that run in parallel to the 330 kV network may result in positive net market benefits, providing economic justification. This network need is listed for the period 2017-2018 to 2021-2022, with a potential solution being a 330 kV line between Dumaresq to Lismore.[53]

5.1.3 NEM Constraint Report 2012

The table below lists the top three most binding system normal constraints that affect flows on the QNI, for both directions in 2012.

The information shows transfer of electricity on the QNI from New South Wales to Queensland is mainly limited by the system normal constraint equations for thermal limits on the Calvale to Wurdong (871) and Calvale to Stanwell (855) lines in Queensland, or the voltage collapse on loss of the largest Queensland generator unit (at Kogan Creek).

Transfer from Queensland to NSW is mainly limited by the transient stability limits for fault on a Hazelwood to South Morang line in Victoria, or Bulli Creek to Dumaresq line.

The table also mentions the market impact of the constraints, including their position in the top ten constraints with the largest market impact. This information makes clear that, although a certain constraint can be binding for a relatively large number of hours, its market impact may still be limited.

---

51 A static VAR compensator is an electrical component for providing fast-acting reactive power on an electricity network.

52 A capacitor is an electrical component used to provide reactive power and can increase power flow in an electrical network.

53 AEMO, 2012 NTNDP, p3-9.

Table 5.1 Binding constraint equations setting the QNI limits in 2012

NSW to QLD limits			
Equation ID	**Hours binding in 2012**	**Description**	**Market impact (with position in top ten market impact constraints per region)**
Q>>NIL_855_871	276.2	System normal constraint, in order to avoid overload on Calvale to Wurdong (871) 275 kV line on trip of Calvale to Stanwell (855) 275 kV line. AEMO notes that this constraint equation is expected to bind for a similar amount in 2013 until Powerlink constructs double circuit 275kV lines between Calvale and Stanwell , expected in late 2013.	$1,431,065 (number four in top ten constraints with largest market impact in Queensland)
N^^Q_NIL_B1, 2, 3, 4, 5, 6 & N^Q_NIL_B	99.5	System normal constraint to avoid voltage collapse on loss of the largest Queensland generator. AEMO notes that this voltage collapse limit is split into 7 constraint equations to co-optimise with each of the 6 largest generators in Queensland. Overall N^^Q_NIL_B1 (for trip of Kogan Creek) binds for the most number of intervals.	$73,013 (number four in top ten constraints with largest market impact in New South Wales)
Q>>NIL_871_855	98.3	System normal constraint, in order to avoid overload on Calvale to Stanwell (855) 275 kV line on trip of Calvale to Wurdong (871) 275 kV line.	$895,184 (number six in top ten of constraints with largest market impact in Queensland)
QLD to NSW limits			
V::N_NILxxx	234.0	System normal constraint to avoid transient instability for fault and trip of a Hazelwood to South Morang 500 kV line. There are 12 constraint equations that make up the transient stability export limit from Victoria and all the binding results have been combined.	Information not mentioned
Q:N_NIL_BCK2L-G	113.5	System normal constraint to avoid transient instability for a 2 phase to ground fault on a Bulli Creek to Dumaresq 330 kV line at Bulli Creek.	$38,412 (number ten in top ten constraints with largest market impact in Queensland)
Q:N_NIL_BI_POT	68.0	System normal constraint to avoid transient instability for a trip of a Boyne Island potline (400 MW).	Does not appear in top ten constraints with largest market impact in either Queensland or New South Wales

5.1.4 Annual Planning Reports review

Augmentations to the QNI

Since QNI was commissioned in 2001, Powerlink and Transgrid have undertaken a number of studies to assess the technical and economic viability of increasing the power transfer capacity in both directions. In addition to these studies, Powerlink, TransGrid and AEMO have over the years also undertaken testing work and refinement of control systems in order to gradually increase the QNI transfer capabilities. This has led to an increase of this capacity from the original 300 to 350 MW in both directions to 700 MW north from New South Wales to Queensland and to 1,078 MW south from Queensland to New South Wales.[54]

In 2012, Powerlink and TransGrid published a Project Specification Consultation Report as part of the first stage of formal consultation in accordance with the RIT-T process, in order to examine the viability of further upgrades to the QNI transfer capacity.

The report describes a number of credible network options that could increase the QNI transfer capability and consequently help with alleviating potential transmission congestion. The network options range in size from lower cost incremental options, capable of providing a modest increase in transfer capability, to large transmission projects involving significant lead times and costs, capable of providing a substantial increase in capability.

The RIT-T process also requires Powerlink and TransGrid to conduct an economic assessment of the market benefits of the various credible options. Among the potential market benefits of an upgrade of the QNI are competition benefits. Powerlink and TransGrid published a consultation paper on the methodology proposed to be used for a quantification of competition benefits in April 2013. Powerlink and TransGrid are now considering submissions to the consultation paper and performing the simulations required to quantify the potential market benefits associated with each upgrade option. The results of this assessment are planned to be communicated to interested parties by the end of 2013.

Augmentations to Queensland infrastructure

As mentioned, Powerlink has committed to building a new 275 kV double circuit transmission line between Calvale and Stanwell substations by summer 2013/2014. The works also involve augmentations to the network out of Calvale, towards Wurdong and Larcom Creek.[55] When constructed, this should alleviate the Q>>NIL_855_871 and Q>>NIL_871_855 constraints, which are the constraints with the highest market impact (see table 4.5).

In addition, Powerlink mentions in its APR for Queensland that grid capability in the South West Queensland zone defines the capability of the transmission system to transfer electricity imports from QNI to the rest of Queensland. The capability of this part of the grid is limited by thermal capacity limitations, occurring on a 330/275 kV

54 Powerlink and TransGrid, *Project Specification Consultation Report - Development of the QNI*, June 2012.

55 Powerlink, *Maintaining a Reliable Electricity Supply within Central Queensland - Final Report*, 27 September 2010, p27.

transformer at Middle Ridge substation or a Braemer to Tarong 275 kV circuit. Increased power generation in the Bulli Creek zone or northerly flows on the QNI cause these limitations to occur.[56] Powerlink notes in its APR that it is addressing this constraint through a number of committed projects which should increase the transfer capacity between the Bulli and South West regions.[57]

Powerlink also notes in its APR that a potential network limitation may arise in the Central Queensland-Southern Queensland section of the transmission network, which is the main corridor for electricity flows between southern and northern Queensland.[58] Under certain conditions, the maximum power transfer between central and southern Queensland and between New South Wales and Queensland is limited by transient instability.

Powerlink notes that, if no new generation locates in southern Queensland, this network limitation between central and southern Queensland is forecast to emerge from summer 2017/18. Depending on future generation developments, feasible network solutions may include establishment of an additional 275kV transmission line development between central and southern Queensland. A feasible network solution could also include an augmentation to QNI and/or Terranora interconnector that increases the northerly power transfer capability from NSW.

Powerlink anticipates undertaking consultation that could give rise to implementing transmission investments to address this imitation in the coming months.[59]

Augmentations to New South Wales infrastructure

As mentioned in the NTNDP, work on the Armidale Static VAr Compensator in order to increase the QNI interconnector's power transfer capability in the Queensland to New South Wales direction has been underway, and TransGrid expects it to be completed in 2013.[60]

TransGrid notes in its APR that upgrades to the QNI transmission capacity may be increased by relieving some of the constraints in the transmission networks connecting to the QNI. This is particularly the case for the capacity of the transmission network north of the Hunter Valley (the Liddell - Tamworth - Armidale lines) and north of Armidale (the 330 kV lines towards Dumaresq and Lismore and the 132/110 kV network from Lismore towards the Terranora interconnector). TransGrid notes that it is investigating the impact of the limited capacity on the Liddell-Tamworth transmission line on the QNI transfer capability and may also consider upgrading its capacity in order to maximise the benefits of QNI upgrade.[61] Similarly, TransGrid notes other augmentations may be required in this area in the longer term, with a potential for a 500 kV high level interconnection with Queensland.[62]

56 Powerlink, Queensland APR 2013, p62.

57 Ibid, p73.

58 Ibid, p75.

59 Ibid, p82.

60 TransGrid, New South Wales APR 2013, p36.

61 Ibid, p53 and 57.

62 Ibid, p58.

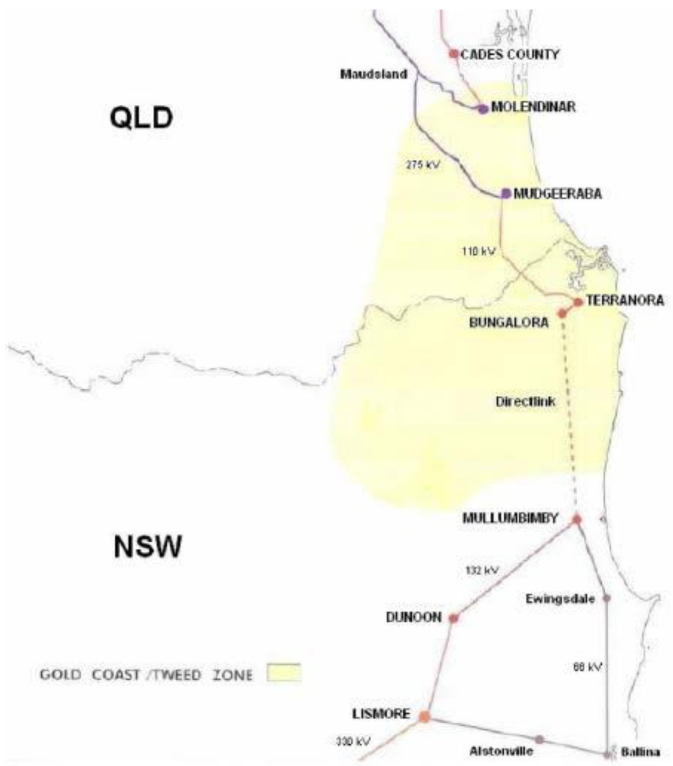
5.2 Terranora interconnector

5.2.1 Introduction

The Terranora interconnector comprises the two 110 kV lines from Terranora in New South Wales to Mudgeeraba in the South East Queensland zone. The controllable element is a 180 MW DC link between Terranora and Mullumbimby (both in New South Wales), known as Directlink, which consists of three separate DC lines.[63] The DC lines were commissioned in 2000, forming the first connection between New South Wales and Queensland. The Terranora interconnector is owned by Energy Infrastructure Investments Pty Ltd.

The South East Queensland zone is a major demand centre that includes the Brisbane area, Sunshine Coast and Gold Coast. It currently has 885 MW of installed generation capacity. AEMO's modelling locates 600 MW of gas-fired generation in the zone by 2026-27, increasing to 1,200 MW by 2031-32. With local demand exceeding installed generation, the South East Queensland zone is a net importer, mainly from the South West Queensland and Central Queensland zones.

Figure 5.2 Terranora/Directlink interconnector



Taken from: APA Group, *Directlink Network Management Plan*, Directlink Joint Venture, May 2013.

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

5.2.2 2012 NTNDP findings

AEMO notes in the NTNDP that the need for increased power transfer capability between Queensland and New South Wales does not arise under its planning assumptions because the augmentation cost outweighs the market benefits. No augmentations of the Terranora interconnector are therefore listed in the NTNDP.

The NTNDP also does not find transmission network development needs for the South East Queensland zone.

5.2.3 NEM Constraint Report

The table below lists the top three most binding system normal constraints on the Terranora interconnector, for both directions in 2012.

In 2012 the majority of the flow on Terranora was restricted by the system normal constraints to avoid voltage collapse on loss of the largest Queensland generator (at Kogan Creek) or to avoid overloading on Lismore to Dunoon 132 kV line (9U6 or 9U7) on trip of the other Lismore to Dunoon 132 kV line (9U7 or 9U6).

Table 5.2 Binding constraint equations setting the Terranora limits in 2012

NSW to QLD limits			
Equation ID	**Hours binding in 2012**	**Description**	**Market impact (with position in top ten market impact constraints per region)**
N^^Q_NIL_B1, 2, 3, 4, 5, 6 & N^Q_NIL_B	66.9	System normal constraint to avoid voltage collapse on loss of the largest Queensland generator. This voltage collapse limit is split into seven constraint equations to co-optimise with each of the six largest generators in Queensland. Overall N^^Q_NIL_B1 (for trip of Kogan Creek) binds for the most number of intervals.	$73,013 (number four in top ten constraints with largest market impact in New South Wales)
N>N-NIL_LSDU	53.9	System normal constraint to avoid overloading Lismore to Dunoon line (9U6 or 9U7) 132 kV line on trip of the other Lismore to Dunoon line (9U7 or 9U6) 132 kV line. AEMO notes this constraint equation only binds when all three Directlink cables are in service.	$115,282 (number two in top ten constraints with largest market impact in New South Wales)
NQTE_ROC	25.0	System normal constraint, rate of change (NSW to Queensland) limit (80 MW / 5 minute) for Terranora interconnector.	$44,818 (number six in top ten constraints with largest market impact in New South Wales)

QLD to NSW limits			
Q>NIL_MUTE_757 & Q>NIL_MUTE_758	18.8	System normal constraint to avoid overloading a Mudgeeraba to Terranora (757 or 758) 110 kV line on no contingencies. These constraint equations are dependent on the Terranora load as well as all three cables of Directlink being in service. In May 2011 the constraint equation Q>NIL_757+758_B was replaced with two constraint equations Q>NIL_MUTE_757 and Q>NIL_MUTE_758. The binding results for each have been combined.	Does not appear in top ten constraints with largest market impact in Queensland or New South Wales.
QNTE_ROC	18.3	System normal constraint. Rate of Change (Qld to NSW) constraint (80 MW / 5 Min) for Terranora Interconnector	Does not appear in top ten constraints with largest market impact in Queensland or New South Wales.
N>N-NIL_MBDU	14.9	System normal constraint to avoid overloading Mullumbimby to Dunoon (9U6 or 9U7) 132 kV line on trip of the other Mullumbimby to Dunoon (9U7 or 9U6) 132 kV line. This constraint equation only binds when all three Directlink cables are in service.	Does not appear in top ten constraints with largest market impact in Queensland or New South Wales.

5.2.4 Annual Planning Report review

Similar to the QNI, flows across the Terranora interconnector are at times constrained by thermal limits on the Liddell - Tamworth line and on the Armidale circuit. As mentioned earlier, TransGrid is considering upgrades to this part of the network in order to alleviate this constraint.

TransGrid also indicates in its APR that it is monitoring the supply towards New South Wales' far north east, including via Essential Energy's 132/110 kV network around Lismore and towards the Terranora interconnector. TransGrid has noted that it has ceased its work on the upgrade of the Dumaresq to Lismore 330 kV line, because the need for upgrade may not be required before 2020. TransGrid will, however, continue to review the electricity forecasts for Far North NSW and closely monitor any change in demand data.[64] To that end, TransGrid and Essential Energy will continue to:

- monitor summer and winter maximum demand;
- monitor the availability of Directlink; and
- work with Directlink to identify opportunities to improve its capacity and/or availability where this is cost-effective.[65]

64 TransGrid website, update on projects. Accessed via: http://www.transgrid.com.au/projects/projects/dumaresq_lismore/Pages/default.aspx

65 TransGrid, New South Wales APR 2013, p63.

5.3 Conclusion Queensland - New South Wales

The NTNDP does not prioritise any augmentations to the capacity of the power flow between Queensland and New South Wales, via either the QNI or Terranora interconnectors. The NTNDP notes potential limitations to the existing capacity, resulting from constraints elsewhere in the network (most notably: the Stanwell to Calvale and Stanwell to Wurdong lines, as well as the lines connecting to the QNI and Terranora interconnector in North New South Wales, on the Liddell-Armidale circuit and around Lismore). These constraints also appear among the most binding constraints between Queensland and New South Wales in the Constraint Report.

Powerlink and TransGrid are currently in the process of studying potential upgrades of the QNI, through a RIT-T procedure. In addition, TransGrid notes it is monitoring the situation in New South Wales North in order to be able to consider in a timely fashion any necessary upgrades should they arise. Powerlink has committed to a new 275 kV double circuit transmission line between Calvale and Stanwell substations by summer 2013/2014 and is studying upgrades of other grid infrastructure in southern Queensland that impact on interconnector flows.

It therefore appears inter-regional transmission infrastructure priorities that currently exist or may arise in the near future are either being addressed, or being monitored, as part of the planning activities in Queensland and New South Wales.

From this information, there do not appear to be obvious planning gaps regarding major inter-regional transmission flow paths between Queensland and New South Wales.

6 Review of inter-regional planning priorities New South Wales - Victoria

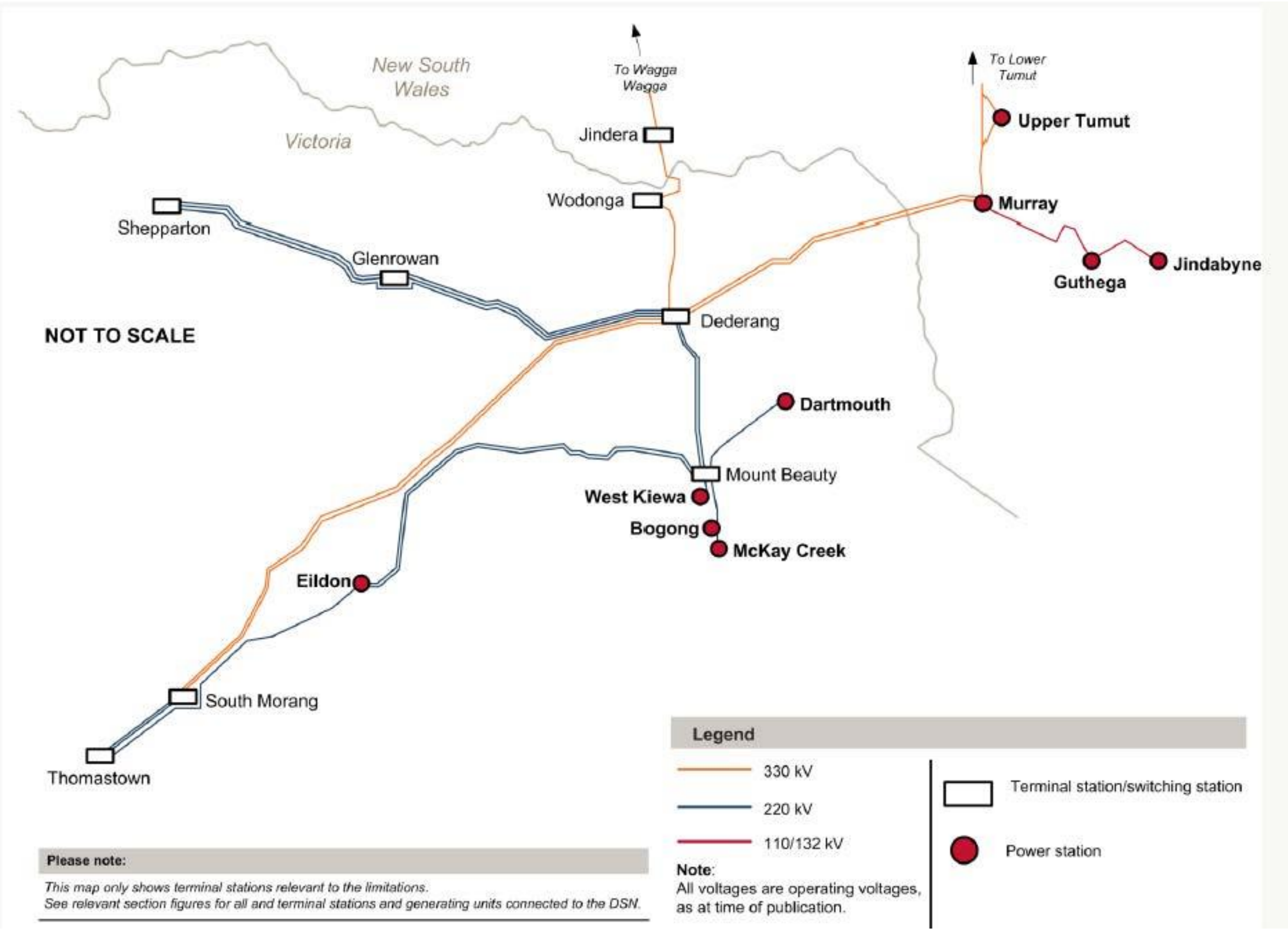
6.1 Introduction New South Wales - Victoria interconnector

New South Wales and Victoria are interconnected via the Victoria to New South Wales interconnector (VIC1-NSW1). It comprises the 330kV lines between Murray and Upper Tumut, Murray and Lower Tumut, Murray and Dederang and Jindera and Wodonga in the Snowy Mountains region. This connects the South West New South Wales region with the Northern Victoria region.

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

The NTNDP mentions the South West New South Wales zone currently has no wind generation, but the amount of wind generation increases from 2016 onwards in AEMO’s model. No other energy source emerges in Northern Victoria according to the NTNDP modelling.

Figure 6.1 NSW VIC interconnectors

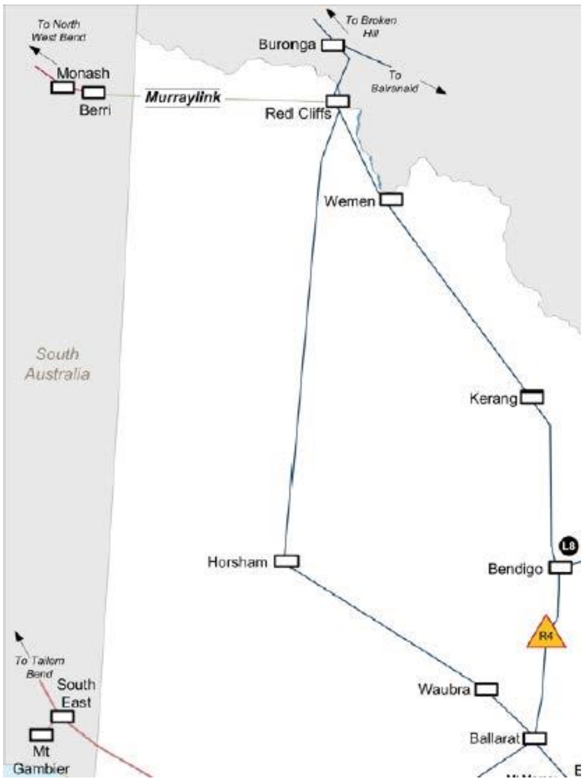


Taken from: AEMO, Victoria APR, p3-30.

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

In the NTNDP modelling, a significant amount of wind generation capacity will be established in the Country Victoria zone. AEMO's model locates this generation at Ballarat, Bendigo, Horsham, Terang and Red Cliffs. This latter location is near the interconnector with New South Wales and South Australia (via Murraylink).

Figure 6.2 NSW - VIC interconnector at Red Cliff



Taken from: AEMO, Victoria APR, p3-5.

6.2 2012 NTNDP findings

In the 2012 NTNDP, AEMO notes that it does not expect limitations involving the main transmission network in the South West New South Wales zone or connections to neighbouring zones to arise in the outlook period if new generation is located according to AEMO's modelled expansion plan. Under these assumptions, there are no South West New South Wales zone transmission network development needs identified in the Planning scenario.

The Victoria to New South Wales interconnector is not augmented under the Planning Scenario, because the augmentation cost exceeds any market benefits gained from the increased power transfer capability.

The NTNDP, however, also notes that the addition of significant amounts of wind generation in the South West New South Wales zone and also around Horsham, Terang or Red Cliffs in Victoria may lead to network limitations in the Country Victoria zone. A number of these limitations have been highlighted in the NTNDP, with the timing being subject to the location, size and timing of proposed wind and solar generation.

6.3 NEM Constraint Report

The table below lists the top three most binding system normal constraints on the Victoria to New South Wales interconnector, for both directions, in 2012.

The New South Wales - Victoria interconnector can bind in either direction for high demand in New South Wales or Victoria. Transfer from Victoria to New South Wales is mainly limited by the transient stability limit for a fault and trip of a Hazelwood to South Morang line or the thermal limits on the South Morang F2 transformer or the Murray to Upper Tumut line.

Transfer from New South Wales to Victoria is mainly limited by voltage collapse for loss of the largest Victorian generator or the thermal limits on the Murray to Dederang or Wagga to Lower Tumut (051) lines.

Table 6.1 Binding constraint equations setting the Victoria to NSW interconnector limits in 2012

VIC to NSW limits			
Equation ID	**Hours binding in 2012**	**Description**	**Market impact (with position in top ten market impact constraints per region)**
V::N_NILxxx	364.0	System normal constraint to avoid transient instability for fault and trip of a Hazelwood to South Morang 500 kV line. There are 12 constraint equations that make up the transient stability export limit from Victoria and all the binding results have been combined.	Information not mentioned
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P	161.0	These system normal constraints avoid overloading the South Morang F2 transformer.	Does not appear in top ten constraints with largest market impact in New South Wales or Victoria.
V>>V_NIL1A_R	46.0	System normal constraint to avoid overloading a South Morang to Dederang 330 kV line for trip of the parallel line.	Does not appear in top ten constraints with largest market impact in New South Wales or Victoria.

NSW to VIC limits			
N^^V_NIL_1	108.1	System normal constraint to avoid voltage collapse for loss of the largest Victorian generating unit.	Does not appear in top ten constraints with largest market impact in New South Wales or Victoria.
V>>V_NIL_1B	7.3	System normal constraint to avoid overloading Dederang to Murray #2 330 kV line for trip of the Dederang to Murray #1 330 kV line.	$199,598 (number one in the top ten of constraints with largest market impact)
N^^V_NIL_2	4.9	System normal constraint to avoid voltage collapse for loss of a Dederang to Murray 330 kV line.	Does not appear in the top ten of constraints with largest market impact in New South Wales or Victoria.

6.4 Annual Planning Report review

Augmentations to the New South Wales - Victoria interconnector

TransGrid mentions in its APR that it has previously worked with AEMO in its capacity as JPB for Victoria on options for improving the New South Wales - Victoria interconnector. This was aimed at improving both the import and export capability, potentially arising because of constraints due to:

- the need for additional New South Wales import; or
- significant renewable energy developments in Victoria.[66]

A number of options have been considered:

- upgrading of Victorian lines and transformers, SVC installation and a braking resistor[67] to improve the Victorian export capability;
- reactive support in the Jindera area, line series compensation[68] of the Lower Tumut – Wagga – Jindera system or other power flow control devices to improve the Victorian import capability; and
- major 330 kV line development to provide a significant increase in the Victoria import capability.[69]

The constraints are now listed as arising over a time frame longer than five years so no immediate planning activities are being undertaken.

66 TransGrid, New South Wales APR 2013, p57.

67 A braking resistor can be temporarily connected to an electricity network to improve the transient stability of an electrical power system by dissipating energy following a fault.

68 Series compensation refers to the insertion of capacitor in series with transmission lines, generally used in order to increase the transfer capability and increase system stability.

69 Ibid, p61.

Augmentations to New South Wales infrastructure

TransGrid notes in its APR that New South Wales relies on imports from the south to serve high demand in the state. This includes imports from Victoria. At times of high demand, import capability is governed by the thermal rating of the four 330 kV lines immediately north of Snowy (around Yass).[70] TransGrid therefore notes there may be market benefits arising from an increase in the capability of this part of the system to assist in meeting the New South Wales peak demand and to increase competition in generation. TransGrid is considering a number of options and has been undertaking a preliminary assessment of the potential market benefits from upgrading this system. Depending on the outcome of this analysis, a regulatory consultation process addressing these limitations will be initiated in the near future.[71]

TransGrid is also considering options to upgrade capacity in the Wagga-Darlington Point area, which can constrain flows on the line towards the interconnector with Victoria at Red Cliffs.[72]

Augmentations to Victoria infrastructure

AEMO in its APR for Victoria notes that limitations on a number of lines in the Northern corridor can pose limitations on the flows between Victoria and New South Wales. In particular, limitations on the Murray - Dederang 330 kV line are among the constraints with the highest market impact (see table 4.5). Although no Victoria to New South Wales interconnector upgrade was modelled (consistent with the 2012 NTNDP), AEMO indicates it continues to monitor these limitations.[73]

AEMO is also undertaking work on the South Morang H1 and H2 330/220 kV transformers.[74] These transformers help supply the Melbourne Metropolitan area, but also form part of the Northern corridor towards New South Wales. AEMO notes that, during maximum demand conditions with high import from New South Wales into Victoria, these transformers can become overloaded. Under certain conditions, imports from New South Wales will need to be reduced to avoid overload. This may cause prices to rise due to the need to dispatch higher-cost generation plant in Victoria, South Australia and Tasmania. As the H1 and H2 transformers are nearing the end of their effective lives in the foreseeable future, AEMO worked with SP AusNet to assess the cost-benefits of installing transformers with higher ratings. This exercise has demonstrated only the replacement of the H1 transformer can be justified by market benefits. The replacement of the H1 transformer is expected to be completed by 2016.[75]

In addition, AEMO is monitoring a number of limitations on lines in the Country Victoria and Northern Victoria zones where congestion may arise if imports from New South Wales were to increase via the interconnector between Buronga and Red Cliffs.

70 Ibid, p54.

71 Ibid, p47.

72 Ibid, p55.

73 AEMO, Victoria APR 2013, p3-31.

74 Transformers are used to influence the relative voltage of electric circuits.

75 Ibid, p3-42.

This includes various circuits between Red Cliffs and Bendigo and between Bendigo and Dederang.

6.5 Conclusion New South Wales - Victoria

The 2012 NTNDP does not prioritise any augmentations to the interconnector capacity between New South Wales and Victoria. It does note limitations may arise on lines in Country Victoria and Northern Victoria if imports via the interconnector between Buronga and Red Cliffs were to increase.

TransGrid and AEMO are undertaking works to upgrade elements of grid infrastructure that affect interconnector flows (eg the upgrade the H1 transformer in Victoria), or are considering such upgrades (eg around Yass and in the Red Cliffs area). They also continue to monitor the capacity of the interconnector between New South Wales and Victoria, as well as that of regional transmission lines potentially affecting the interconnector flows.

From this information, there do not appear to be obvious planning gaps regarding major inter-regional transmission flow paths between New South Wales and Victoria.

7 Review of inter-regional planning priorities Victoria - South Australia

Victoria and South Australia are interconnected via the Heywood and Murraylink interconnectors.

7.1 Heywood interconnector

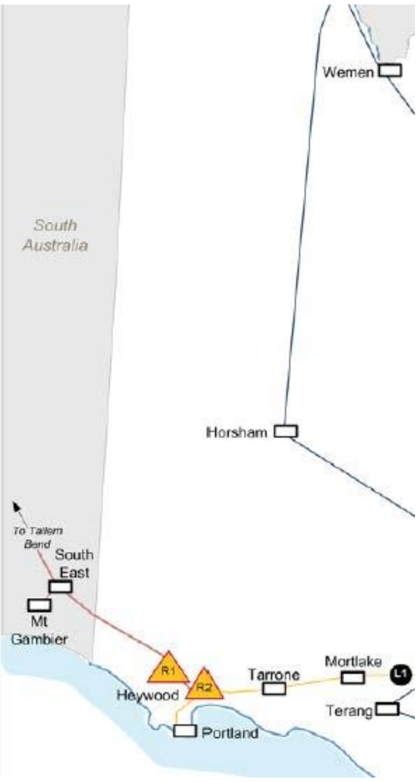
7.1.1 Introduction Heywood interconnector

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

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

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

Figure 7.1 Heywood interconnector



AEMO, Victoria APR, p3-5.

Until recently, the vast majority of the time the flow on the Heywood interconnector was from Victoria to South Australia. With an increasing number of wind farms in South Australia, the flow is now often from South Australia to Victoria. In March 2010 the limit from South Australia to Victoria on Heywood 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 Australian network following a South Australian generator trip; and
- thermal limitations on the underlying 132 kV transmission system in the South East South Australia zone.[76]

The current capacity limitation affects the extent to which electricity can flow across the interconnector. Specifically it affects the amount of generation from other regions in the NEM which can be used to meet peak demand conditions in South Australia. It also restricts the amount of wind generation which can be exported from South Australia at times of high wind output but low South Australian demand.[77]

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

The study found that expanding the transfer capacity of the Heywood Interconnector would relieve the current limitations, and would increase both import and export capability. This would then 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 NEM) and reduced capital costs associated with meeting the LRET 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.[78]

A number of options were considered for upgrading the interconnector capability. The preferred option is to install a third transformer and 500 kV bus-tie at Heywood in Victoria, series compensation on 275 kV transmission lines in South Australia, and 132 kV network reconfiguration works in South Australia. This is expected to increase

76 ElectraNet, South Australia APR 2013, p25.

77 AEMO and ElectraNet, *South Australia – Victoria (Heywood) Interconnector Upgrade - RIT-T: Project Specification Consultation Report*, p3.

78 Ibid.

interconnector capability by about 40% in both directions, enabling increased wind energy exports from South Australia and also increasing lower-cost generation imports into South Australia.[79]

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 AER in April 2013 for a determination on whether the preferred options satisfies the RIT-T. The AER found that the option identified by ElectraNet and AEMO in their report provides the maximum economic benefits, and satisfies the requirements of the RIT-T. The upgrade would increase the capability of the network to transfer electricity between the two regions.[80]

The AER notes 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.

The determination means ElectraNet can now apply to the AER for an allowance for the cost of the Heywood interconnector upgrade to be included in charges during the 2013–2018 period. The AER will review ElectraNet's proposal and decide how much it will be allowed to charge to recover the efficient costs attributable to the upgrade.

The actual investment decision will be made by ElectraNet and AEMO. The estimated commissioning date is July 2016.

7.1.2 2012 NTNDP findings

In the 2012 NTNDP modelling, the Heywood interconnector upgrade project (assumed to be committed in the NTNDP analysis) will defer the need for further upgrades of the Victoria to South Australia interconnector for the outlook period. This is due to the cost of further interconnector augmentation outweighing any market benefits gained from increased power transfer capability between the two regions.

Emerging major transmission network limitations within the South East South Australia zone are not expected to arise during the outlook period due to a number of network augmentations to be implemented as part of the Heywood interconnector upgrade project. Equally, no transmission needs impacting the Heywood interconnector flows are listed as necessary for Victoria in the NTNDP.

7.1.3 NEM Constraint Report

The table below lists the top three most binding system normal constraints on the Heywood interconnector, for both directions in 2012.

Victoria to South Australia flow is most often restricted by the transient stability limit for a fault on a Hazelwood to South Morang 500 kV line or the voltage collapse for the loss of the largest generator in South Australia. Export from South Australia is mainly

79 AEMO, Victoria APR 2013, p3-16.

80 AER, press release, 4 September 2013.

restricted by the thermal limits on the South East substation 275/132 kV transformers and the South Morang F2 transformer.

Table 7.1 Binding constraint equations setting the Heywood limits in 2012

<table>
<tr><td colspan="4">VIC to SA limits</td></tr>
<tr><td>Equation ID</td><td>Hours binding in 2012</td><td>Description</td><td>Market impact (with position in top ten of market impact constraints per region)</td></tr>
<tr><td>V::N_NILxxx</td><td>348.9</td><td>System normal constraint to avoid transient instability for fault and trip of a Hazelwood to South Morang 500 kV line.

There are 12 constraint equations that make up the transient stability export limit from Victoria and all the binding results have been combined.</td><td>Information not mentioned</td></tr>
<tr><td>V^^S_NIL_MAXG_xxx</td><td>220.3</td><td>System normal Victoria to SA long term voltage stability limit for loss of the largest credible generation contingency in SA, South East capacitor bank on / off.</td><td>Does not appear in top ten constraints with largest market impact in Victoria or South Australia.</td></tr>
<tr><td>VS_HYTS_TX</td><td>99.7</td><td>System normal upper transfer limit from Victoria to SA on Vic-SA based on Heywood transformer 30 minute rating and tertiary winding MW load</td><td>Does not appear in top ten constraints with largest market impact in Victoria or South Australia.</td></tr>
<tr><td colspan="4">SA to VIC limits</td></tr>
<tr><td>S>>V_NIL_SETX_SETX</td><td>422.3</td><td>System normal constraint to avoid overloading a South East 275/132 kV transformer on trip of the remaining South East 275/132 kV transformer.</td><td>$156,867

(number eight in the top ten constraints with largest market impact in South Australia)</td></tr>
<tr><td>V>>V_NIL_2A_R &
V>>V_NIL_2B_R &
V>>V_NIL_2_P</td><td>149.3</td><td>These system normal constraints avoid overloading the South Morang F2 transformer.</td><td>Does not appear in top ten constraints with largest market impact in Victoria or South Australia.</td></tr>
<tr><td>S>V_NIL_HYTX_HYTX</td><td>8.3</td><td>System normal constraint to avoid overloading a Heywood 275/500 kV transformer on trip of the other Heywood 275/500 kV transformer.</td><td>Does not appear in top ten constraints with largest market impact in Victoria or South Australia.</td></tr>
</table>

7.1.4 Annual Planning Reports review

Augmentations to the Heywood interconnector

Both APRs mention the Heywood interconnector upgrade project as an ongoing part of their transmission network planning priorities.

Augmentations to South Australia and Victoria infrastructure

Besides the Heywood interconnector upgrade project, the South Australia APR does not contain further projects impacting on the flow between South Australia and Victoria via the Heywood interconnector.

In addition to the planned Heywood interconnector upgrades, AEMO indicates in the Victoria APR that voltage instability may arise on the South-West corridor in Victoria, which runs between Portland and Moorabool (near Geelong), due to upgrades of the Heywood interconnector capacity. AEMO notes it is monitoring these limitations.

7.2 Murraylink interconnector

7.2.1 Introduction Murraylink interconnector

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

The Country Victoria zone currently has 312 MW of installed wind generation capacity, but as mentioned, in the 2012 NTNDP modelling, the amount of wind generation capacity increases significantly in this zone. AEMO's modelling locates this generation at Ballarat, Bendigo, Horsham, Terang and Red Cliffs.

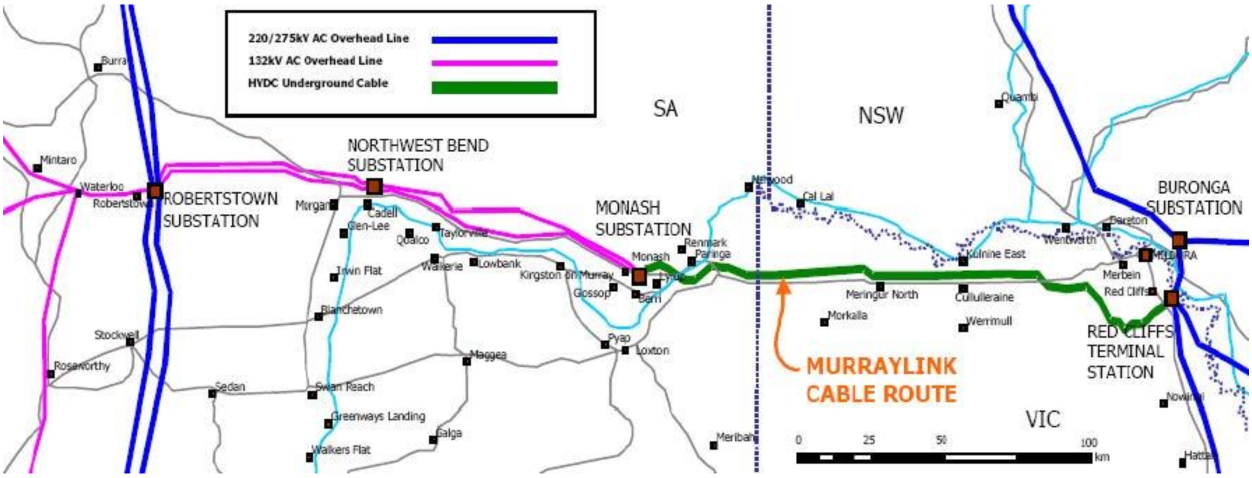
The North South Australia zone, which covers the Mid-North, Upper North, Eyre Peninsula and Riverland areas, accounts for approximately 20% of the region's total demand. The zone is connected to the Adelaide zone via four 275 kV circuits and one 132 kV circuit. The zone currently has 844 MW of installed wind generation capacity and 318 MW of gas. The 770 MW of coal fired generation currently installed is forecast to be retired in the NTNDP modelling by 2031-32. Solar power is expected to increase under the NTNDP modelling from 0 MW currently to 400 MW from 2021-2022.

AEMO expects that throughout the outlook period, the North South Australia zone continues to be a net power importer at the time of the 10% probability of exceedence (POE) summer maximum demand in South Australia[81], even though the North South Australia zone accounts for approximately 30% of South Australia's total non-wind generation under the Planning scenario. In the NTNDP, this is attributed to the high cost of OCGT generation in this zone, demand growth, and the low coincidence factor

81 The 'probability of exceedence' is used in maximum demand forecasts. Maximum demand forecasts are represented by a statistical distribution (rather than a single value). Distributions are represented by 10%, 50%, and 90% probability of exceedence (POE) maximum demand projections. The 10% POE represents "1 in 10 years hot weather", ie temperatures (and associated maximum demand levels) only expected to occur one year in 10.

between solar generation and South Australia's 10% POE summer maximum demand.[82]

Figure 7.2 Murraylink interconnector



Taken from: Australian Pipeline Trust, *Acquisition of Murraylink Transmission Company*, 30 March 2006.

7.2.2 2012 NTNDP findings

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

Regarding connections to neighbouring zones in Victoria, the NTNDP notes that the modelled increase in the amount of wind generation capacity in the Country Victoria zone could lead to limitations on a number of lines in Country Victoria zone, including the Moorabool - Ballarat 220 kV line and the line between Red Cliffs and Kerang.

The NTNDP notes that no limitations involving the main transmission network in the North South Australia zone or connections to neighbouring zones are forecast to arise in the outlook period if new generation is located according to the patterns AEMO modelled. Under these assumptions, there are no North South Australia zone transmission network development needs identified under the Planning scenario.

7.2.3 NEM Constraint Report

Table 7.2 lists the top three most binding system normal constraints on the Murraylink, for both directions in 2012.

Transfers from Victoria to South Australia via the Murraylink interconnector are mainly limited by constraint equations that affect the export from Victoria as a whole, such as the South Morang F2 transformer overload, or the transient stability limit for exports from Victoria.

Many of the thermal issues closer to Murraylink are dealt with by the Murraylink runback scheme.[83] Transfers from South Australia to Victoria on the Murraylink are

82 The 'low coincidence factor' refers to the fact that, typically, the timing of maximum output from solar generation (typically, during the day) does not perfectly align with the timing of maximum demand on hot days (typically, in the afternoon).

limited by the 132 kV lines from Robertstown to Monash and Robertstown to Waterloo as well as the Robertstown 275/132 kV transformers.

Table 7.2 Binding constraint equations setting the Murraylink limits in 2012

VIC to SA limits			
Equation ID	**Hours binding in 2012**	**Description**	**Market impact (with position in top ten market impact constraints per region)**
V::N_NILxxx	362.3	System normal constraint to avoid transient instability for fault and trip of a Hazelwood to South Morang 500 kV line. There are 12 constraint equations that make up the transient stability export limit from Victoria and all the binding results have been combined.	Information not mentioned
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P	157.3	These system normal constraints avoid overloading the South Morang F2 transformer.	Does not appear in top ten constraints with largest market impact in Victoria or South Australia.
V>>V_NIL1A_R	44.8	System normal constraint to avoid overloading a South Morang to Dederang 330 kV line for trip of the parallel line.	Information not mentioned
SA to VIC limits			
S>V_NIL_NIL_RBNW	72.5	System normal constraint to avoid overloading the North West Bend to Robertstown 132 kV line on no line trips This constraint equation normally sets the upper limit on Murraylink.	$113,505 (number ten in the top ten constraints with largest market impact in South Australia)
S>>V_NIL_RBTXW_ RBTX1	46.8	System normal constraint to avoid overloading Robertstown #1 275/132 kV transformer on trip of the Robertstown #2 275/132 kV transformer.	$158,347 (number seven in the top ten constraints with the largest market impact in South Australia)

83 The runback scheme reduces the active power in the event of contingencies in the network, when an important transmission line in the receiving or the supplying network is tripped.

7.2.4 Annual Planning reports Review

Augmentations to the Murraylink interconnector

No augmentations to the Murraylink interconnector transfer capacity are considered in the Victoria and South Australia APRs.

Augmentations to South Australia and Victoria infrastructure

ElectraNet states in the South Australia APR that the import capability of the Murraylink interconnector is influenced by the capability of supply networks in South Australia and Victoria, which vary with network loading and outage conditions. ElectraNet notes that network limit equations that describe limitations in the Riverland region of South Australia, assuming system normal conditions, depend on the import and export capability of the Murraylink interconnector.[84]

In particular, limitations on the Robertstown - North West Bend line in the Riverland region in South Australia could occur if no power is being imported through the Murraylink interconnector into South Australia at peak load times. Forecast 10% Probability of Exceedence demand in the Riverland region is currently at a level such that, if no power is being imported through the Murraylink interconnector to South Australia at peak load times, an outage of the Robertstown – North West Bend No. 2 132 kV line would overload the thermal rating of the Robertstown – North West Bend No. 1 132 kV line.[85]

This forecast potential overload can be avoided, according to ElectraNet, if the level of import to South Australia through the Murraylink interconnector is above a certain level. The amount of required import through the Murraylink interconnector to avoid such an overload at forecast peak load times increases from year to year, as the demand forecast for the Riverland region increases.

In this respect, ElectraNet states that the capability of the Murraylink interconnection to inject power into South Australia is influenced by the ability of the Victorian transmission system to supply Murraylink, especially under high demand conditions in Victoria. Thermal limits on the Ballarat to Moorabool, Ballarat to Bendigo and Red Cliffs to Kerang lines 220 kV lines are particularly severe.

AEMO is currently addressing these constraints through a RIT-T process. AEMO mentions that potential overload on the existing Ballarat–Bendigo 220 kV line and the Moorabool–Ballarat No.1 220 kV line may occur under a combination of the following conditions:

- high ambient temperature leading to a 1-in-10-year maximum demand occurrence;
- low wind speed affecting the ability of the transmission lines into Ballarat and Bendigo to transmit the required energy;
- constrained import into Victoria across the Murraylink Interconnector due to limitations on South Australia's Riverland network; and

84 ElectraNet, South Australia APR 2013, p28.

85 Ibid, p31.

- constrained import into Victoria across the New South Wales interconnectors.[86]

AEMO notes that, while these events are unlikely, the consequence should they occur may result in the requirement to reduce demand by up to 251 MW in 2013–14.

AEMO has proposed a preferred option that addresses this network limitation. AEMO noted that the RIT-T has demonstrated that the upgrade would deliver a positive market benefit through significant reductions in involuntary load shedding over the long term.[87] The project is expected to increase the capability of the Ballarat - Bendigo line by about 50% and the combined capability of the Moorabool - Ballarat lines by about 65%.

The South Australia APR notes ElectraNet and AEMO are undertaking joint planning in order to:

- confirm the capability of the Victorian network, which will consider the capability of the Victorian network now and after the completion of the western Victorian RIT-T; and
- identify the optimal timing for the commencement of a joint RIT-T process to reinforce supply to the Riverland region.

ElectraNet also notes that generation installed in the Riverland 132 kV transmission system and in the eastern region of the Mid North 132 kV transmission system can potentially displace import on the Murraylink interconnector.

The AEMC understands that the S>V_NIL_NIL_RBWN constraint, which is among the constraints with the highest market impact in South Australia, is being considered as part of the joint analysis by ElectraNet and AEMO. An increase of the line rating on the Robertstown - North West Bend #1 line is being considered, which should increase the limit on Murraylink from 160-175 MW to around 200 MW instead.

AEMO has also indicated that the S>>V_NIL_RBTXW_RBTX1 constraint, which is also among the constraints with the highest market impact (see table 4.5), has been removed from 'system normal', and has been made part of the Murraylink runback scheme. This means that overload of the second Robertstown transformer is managed by rapidly reducing the flow on Murraylink.

7.3 Conclusion Victoria - South Australia

Work is ongoing regarding the augmentation of the Heywood interconnector connecting Victoria and South Australia in the south. The NTNDP does not list an additional need for upgrading Victoria - South Australia interconnector capacity.

AEMO as JPB for Victoria is undertaking additional planning regarding potential limitations on transmission lines in Victoria arising from increased flow via the Heywood interconnector.

AEMO and ElectraNet are also undertaking planning activities in order to improve electricity flows over the Murraylink interconnector which connects these states in the

86 AEMO, *Regional Victoria Thermal Capacity Upgrade RIT-T Assessment Conclusion Report*, 10 October 2013.

87 AEMO, Victoria APR 2013, p3-19.

north. AEMO is currently undertaking a RIT-T process to address thermal limitations on transmission lines in Victoria which impact on the electricity flows via Murraylink into South Australia. ElectraNet in its APR for South Australia mentions further (joint) planning will be undertaken.

From this information there do not appear to be obvious planning gaps regarding major inter-regional transmission flow paths between Victoria and South Australia.

8 Review of inter-regional planning priorities Victoria - Tasmania

8.1 Introduction Basslink interconnector

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

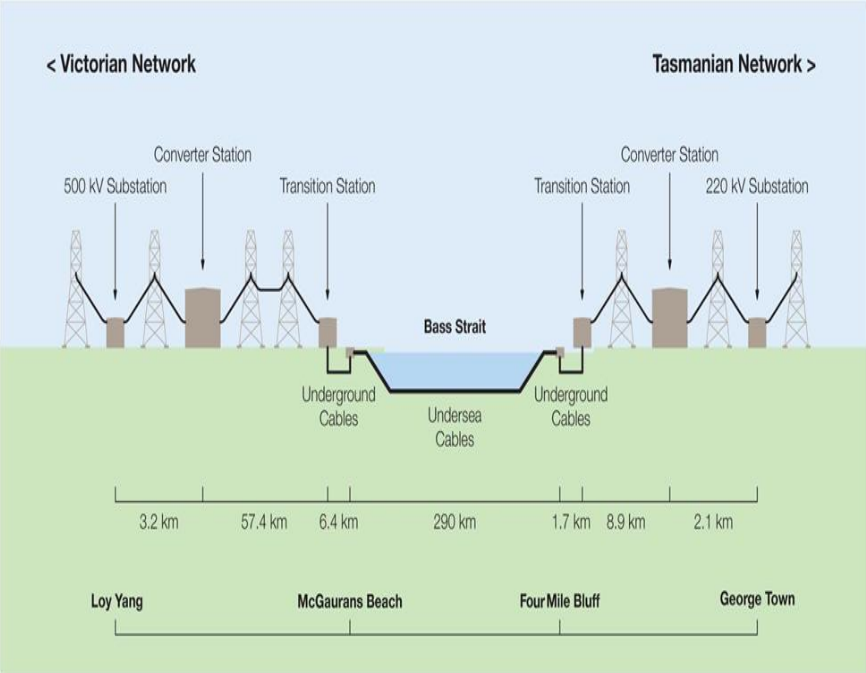
The Latrobe Valley zone has a significant amount of coal-fired generation. It is a major exporter of energy, principally to Melbourne and Geelong (via its 500 kV and 220 kV transmission networks - the 'Eastern corridor'), and also to regional Victoria and Tasmania. In the NTNDP modelling, approximately 26% of brown coal-fired generation is retired in the outlook period (884 MW from 2016-17 and another 800MW between 2031-32 and 2036-37). In the modelling, it is replaced by increased gas-fired generation, some wind generation and also, in the longer term, biomass. The NTNDP modelling finds that new generation (coupled with moderate demand growth) in the zone will be slightly less than modelled retirements, but that the Latrobe Valley will continue to be a net exporter throughout the outlook period.

Under AEMO's modelling assumptions, the new generation will be located in the same location as the existing coal generation, or connected to the Hazelwood 500 kV station. This enables the existing transmission network to accommodate the new generation with minimal (or no) new transmission investment.[88]

The Tasmania zone has a significant amount of hydroelectric generation, geographically dispersed across the region. In the NTNDP modelling, 1,060 MW of new wind-generated capacity is established from 2021-22 onwards in this zone.

88 AEMO, 2012 NTNDP, p3-14, 3-15.

Figure 8.1 Basslink interconnector



Taken from: Cigre, *HVDC and Power Electronics projects in Australia and New Zealand*, 2011.

8.2 2012 NTNDP findings

A second high capacity link, increasing Victoria to Tasmania interconnector capability, is not found to be economic under the Planning Scenario for the outlook period. This is due to the cost of the project outweighing the market benefits gained from increased power transfer capability between the two regions. The analysis is based on additional new wind generation of 1,000 MW in Tasmania with the existing Victoria to Tasmania interconnector and 1,700 MW with a second Victoria to Tasmania interconnector.[89]

In the NTNDP modelling for both the Latrobe Vally and the Tasmania zones, no limitations involving the main transmission networks or connections to neighbouring zones arise in the outlook period if new generation is located according to the patterns AEMO modelled. Under these assumptions, there are no transmission network development needs identified under the Planning scenario for either zone.[90]

The NTNDP, however, notes that limitations on lines within the Tasmania zone may arise during periods of high wind generation and moderate levels of demand, coupled with maximum levels of export to Victoria, if substantial amounts of wind generation were to be realised.

89 Ibid, p3-15.

90 Ibid, p3-25.

8.3 NEM Constraint Report

The table below lists the top three most binding system normal constraints on the Basslink interconnector, for both directions in 2012.

The energy constraint equations that can limit Basslink flow from Victoria to Tasmania are the transient stability limits for a fault and trip of a Hazelwood to South Morang line. Flows from Tasmania to Victoria are mainly limited by the South Morang F2 transformer overload constraint equations. Basslink is mainly limited by frequency control ancillary services or the frequency control system protection scheme (established to maintain system frequency within standards) constraint equations.

Table 8.1 Binding constraint equations setting the Basslink interconnector limits in 2012

TAS to VIC limits			
Equation ID	**Hours binding in 2012**	**Description**	**Market impact (with position in top ten market impact constraints per region)**
F_T++NIL_TL_L60	1465.3	Tasmania lower 60 second requirement for loss of two Comalco potlines, Basslink able to transfer FCAS.	Does not appear in top ten constraints with largest market impact in Victoria or Tasmania.
F_T++NIL_TL_L6	951.2	Tasmania lower 6 second requirement for loss of two Comalco potlines, Basslink able to transfer FCAS.	Does not appear in top ten constraints with largest market impact in Victoria or Tasmania.
F_MAIN++NIL_MG_R6	534.4	Mainland raise 6 second requirement for a mainland generation event, Basslink able to transfer FCAS.	Does not appear in top ten constraints with largest market impact in Victoria or Tasmania.
VIC to TAS limits			
F_MAIN++ML_L5_0400	586.1	Mainland lower 5 minute requirement for a mainland load event, Basslink able to transfer FCAS.	Does not appear in top ten constraints with largest market impact in Victoria or Tasmania.
V::N_NILxxx	240.7	System normal constraint to avoid transient instability for fault and trip of a Hazelwood to South Morang 500 kV line. There are 12 constraint equations that make up the transient stability export limit from Victoria and all the binding results have been combined.	Information not mentioned
V_T_NIL_FCSPS	230.8	Basslink limit from Victoria to Tasmania for load enabled for the Basslink frequency control special protection scheme (FCSPS)	$94,121 (number four in the top ten constraints with largest market impact in Victoria)

8.4 Annual Planning Reports review

Upgrade to Victoria - Tasmania interconnection capacity

Consistent with the 2012 NTNDP, an augmentation of the interconnector capacity between Victoria and Tasmania is not considered in the APRs for Victoria and Tasmania.

Augmentations to Victoria and Tasmania infrastructure

AEMO mentions in the Victoria APR that the Hazelwood - Loy Yang 500 kV line and the Latrobe Valley - Melbourne 500 kV line could pose limitations in a situation of increased import into Victoria via the Basslink. For this reason, AEMO subjects these limitations to ongoing monitoring.[91]

Transend has previously carried out a study into the effects of increased wind generation on the stability of its system and import/export levels of the Basslink interconnector. The study found these effects are potentially significant. Transend therefore notes in its 2013 APR that it continues to investigate these effects.[92]

Transend is also undertaking a number of projects in the George Town area to increase reliability and capacity of this part of the transmission system. This includes projects on parts of this network that potentially affect interconnector flows across Basslink (such as on the George Town - Sheffield 220 kV line).[93]

8.5 Conclusion Victoria - Tasmania

The 2012 NTNDP does not prioritise any augmentations to the interconnector capacity between Victoria and Tasmania.

From the 2012 Victoria and Tasmania APRs it appears both AEMO and Transend are monitoring and/or addressing potential limitations within their networks that could affect interconnector flows via Basslink.

From this information, there do not appear to be obvious planning gaps regarding major inter-regional transmission flow paths between Victoria and Tasmania.

---

91 AEMO, Victoria APR 2013, p3-6.

92 Transend, *Future wind generation in Tasmania, Executive Summary*, May 2009.

93 Transend, Tasmania APR 2013, p93.

9 New South Wales - South Australia

There is currently no direct interconnection between New South Wales and South Australia.

In its APR for New South Wales, TransGrid however suggests there is potential for such an interconnection in the future.[94] In part this is driven by the potential to develop substantial amounts of renewable energy in South Australia (wind and geothermal). TransGrid notes the existing South Australia – Victoria interconnection and size of the South Australian demand places limitations on the ability to absorb this generation in South Australia.

TransGrid therefore notes there is potential for the development of a direct interconnection between South Australia and New South Wales. This interconnection could be developed as a 500 kV AC link or a high-voltage DC link or a combination of both.

This interconnection has a number of advantages, according to TransGrid, as it would:

- enable the connection of significant levels of renewable energy sources in South Australia by increasing the interconnection capability with the eastern States;
- provide a transmission path to transfer excess renewable energy from South Australia to NSW;
- enable the transfer of base-load energy to South Australia;
- reinforce the existing South Australia – Victoria and Victoria – New South Wales interconnections and improve the capability for power transfer between the states;
- facilitate the potential for wind farm development near Broken Hill; and
- provide access to large areas that are suitable for solar power developments.

The TransGrid APR lists this potential interconnector as an 'indicative development', appearing on a time frame longer than five years.

94 TransGrid, New South Wales APR, p61.

10 Conclusion on the exercise LRPP in 2013

10.1 Summary table

The table below provides a summary of the findings of the review undertaken in the previous chapters.

Table 10.1 Summary NTNDP and APRs

Interconnection	NTNDP	APRs
Queensland - New South Wales	A need to increase capacity on the QNI and Terranora interconnectors between Queensland and New South Wales does not arise under the NTNDP planning scenarios. The NTNDP does not find investment needs in the central and southern Queensland zones regarding transmission infrastructure which impacts on interconnector flows, taking account of already committed projects by Powerlink: • an augmentation of the circuit between Calvale and Stanwell; and • a number of works around Braemar substation. Additional needs may arise if actual generation development differs from AEMO's modelled expansion plan. For New South Wales, the NTNDP built on works already being addressed by TransGrid: • installation of a power oscillator damper on the Armidale SVC; and • a new 200 MVar capacitor at the Armidale substation. The NTNDP notes limitations on the QNI may arise as a result of limitations on the parallel 132 kV network in the North NSW zone.	Powerlink and TransGrid are currently undertaking a RIT-T process to examine potential augmentations to the QNI. For Queensland, in addition to the already mentioned projects around Stanwell and Braemar, Powerlink anticipates undertaking consultation to examine potential limitations between south Queensland and central Queensland. A potential solution may involve augmentation of the QNI and/or Terranora interconnector. TransGrid notes in its APR it is examining the effects of the network capacity around Liddell and Lismore in the North NSW zone on the QNI tranfer capability and may consider upgrading this capacity. TransGrid also indicates that it will monitor the availability of the Terranora interconnector and will work with Directlink to identify opportunities to improve its capacity and/or availability where this is cost-effective.
New South Wales - Victoria	The Victoria to New South Wales interconnector is not augmented in the modelling under the Planning Scenario, because, under these assumptions, the augmentation cost exceeds any market benefits gained from the increased power transfer capability. The NTNDP notes some limitations may occur in the Country Victoria zone if a large amount of wind generation was to be installed there, as modelled in AEMO's expansion plan.	TransGrid mentions in its APR that it has previously worked with AEMO in its capacity as JPB for Victoria to consider options for improving the New South Wales - Victoria interconnector. The constraints are now listed as arising over a time frame longer than five years so no immediate planning activities are being undertaken. TransGrid and AEMO are undertaking a number of planning activities regarding regional infrastructure which may impact on inter-regional flows:

		• potential upgrades of the NSW network around Yass, with a consultation process expetect in the near future; • potential upgrades in the Wagga - Darlington Pointarea in NSW; • work on the H1 transformer at South Morang in VIC; • monitoring of the limitations on the Murray - Dederang line in VIC; and • monitoring potential limitations in the Country Victoria zone.
Victoria - South Australia	The NTNDP mentions the Heywood upgrade project and expects that this defers the need for further upgrades of the Victoria to South Australia interconnector for the outlook period. No need for upgrade of the Murraylink interconnector was found in the NTNDP. The NTNDP notes some limitations may occur in the Country Victoria zone if a large amount of wind generation was to be installed there, as modelled in AEMO's expansion plan.	AEMO is currently undertaking a RIT-T process to address limitations in the Country Victoria zone which impact on interconnector flows via Murralink. ElectraNet notes it is undertaking joint planning activities with AEMO to further address limitations to flows via Murraylink.
Victoria - Tasmania	A second high capacity link, increasing Victoria to Tasmania interconnector capability, is not found to be economic under the Planning Scenario in the NTNDP. The NTNDP does not list transmission network development needs for the zones in Victoria and Tasmania connecting to Basslink.	AEMO and Transend are undertaking a number of planning activities regarding regional infrastructure which may impact on inter-regional flows: • monitoring potential limitations on the Hazelwood - Loy Yang 500 kV line and the Latrobe Valley - Melbourne line in VIC; • undertaking studies of the effects of wind generation on the import/export capacity of Basslink; and • work in the George Town area in TAS to increase reliability and capacity in this part of the network.
New South Wales - South Australia	New South Wales and South Australia are currently not directly interconnected. The potential for such an interconnection is not considered in the NTNDP.	TransGrid notes in its APR that there is potential for the development of a direct interconnection between South Australia and New South Wales. This interconnection could be developed as a 500 kV AC link or a high-voltage DC link or a combination of both. The TransGrid APR lists this potential interconnector as an 'indicative development', appearing on a time frame longer than five years.

10.2 Conclusion

As described in section 3.2, the purpose of the last resort planning power is to ensure timely and efficient inter-regional transmission investment for the long term interests of consumers of electricity.

Under the LRPP, the AEMC has the power to direct a participant to undertake a RIT-T if the Commission considers there has been insufficient consideration of an inter-regional transmission constraint in the planning activities of a JPB.

To assess the potential need for exercising the LRPP in 2013, the Commission has reviewed the 2012 NTNDP and the planning reports of the jurisdictional planning bodies. The purpose of this exercise is to examine whether transmission investment needs that are considered necessary for the development of the critical flow paths between regions in the NEM, identified in the NTNDP, are being addressed in the planning activities of jurisdictional planners.

In the NTNDP, AEMO notes that significant changes in the input conditions, most notably a decline in demand growth, impact on the level of transmission infrastructure investment required in the planning period.

In terms of augmentations to interconnectors, the 2012 NTNDP only lists upgrade of the Heywood interconnector as a planning priority. This upgrade is being addressed by AEMO and ElectraNet via a RIT-T process, and has recently received regulatory approval.

The NTNDP also lists a number of other constraints in transmission infrastructure further removed from the actual interconnector which arise or could arise in the future under its planning assumptions, for consideration by jurisdictional planners.

From the information included in the jurisdictional annual planning reports, it appears the JPBs are addressing the transmission investment needs identified in the 2012 NTNDP. In addition, they are undertaking planning activities, either in the form of ongoing monitoring or more advanced studies or RIT-T processes, aimed at examining potential upgrades to their networks which may not be mentioned in the NTNDP. This includes both potential upgrades of interconnectors themselves, or of transmission lines which may impact on interconnector transfer capability. These activities appear to be covering the constraints that have the greatest market impact.

From analysis of the relevant planning documents, there do not appear to be obvious planning gaps regarding major inter-regional transmission flow paths.

The Commission therefore considers there is no need to exercise the LRPP in 2013.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
ESOO	Electricity Statement of Opportunities
JPB	jurisdictional planning bodies
LRPP	last resort planning power
MCC	marginal cost of constraint
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
NER	National Electricity Rules
NTNDP	National Transmission Network Development Plan
RIT-T	regulatory investment test - transmission
SCER	Standing Council on Energy and Resources
TNSP	transmission network service provider