Australian Energy Market Commission

REVIEW

DECISION REPORT

Last resort planning power - 2017 review

07 November 2017

Reference: EPR0061
Decision report

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About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Summary

The Australian Energy Market Commission (AEMC or Commission) has determined not to exercise its last resort planning power in 2017.

From the analysis undertaken for the 2017 review, the Commission has concluded that transmission network service providers are appropriately including inter-regional transmission priorities in their planning activities.

Reasons for Commission's decision

To assist it in determining whether to exercise the last resort planning power in 2017 and in accordance with the last resort planning power guidelines, the Commission has reviewed the transmission network service providers' annual planning reports, published in 2017, against the constraints on the transmission network forecast by the Australian Energy Market Operator (AEMO) in the National Transmission Network Development Plans (NTNDPs) for 2016 and 2015, published in December 2016 and November 2015 respectively.[1] The Commission has also considered the National Electricity Market (NEM) constraints report 2016 published by AEMO and other information such as relevant regulatory investment test reports published by the transmission network service providers (TNSPs).

Upon reviewing relevant planning documents, the Commission has come to a view that all inter-regional flow constraints in the NEM are being adequately examined by the network service providers. TNSPs continue to address or monitor constraints on the infrastructure connecting the NEM regions and the infrastructure within their networks that could impact on inter-regional electricity flows in their 2017 transmission annual planning reports. For example, the Heywood interconnector upgrade was completed in mid-2016 to raise its nominal transfer capacity from 460 MW to 650 MW and TransGrid has identified several network augmentation options for Northern New South Wales which may increase the transfer capacity across QNI.

Current interconnection studies for the NEM

The Commission notes that the regulatory framework is facilitating feasibility studies to explore future interconnector development options for the NEM. These studies are being undertaken by a number of stakeholders in the electricity market to explore the benefits that may be associated with the upgrades.

AEMO’s 2016 NTNDP included a further interconnection analysis for the NEM, where it considered a range of possible interconnector development options and provided an overview of the potential market benefits associated with them. The assessment identified three network development options that had net positive benefits associated with them if competitively priced, the options included:[2]

1 Note that there has been a change in the naming convention for the NTNDP year adopted by the LRPP review to align it with the naming convention used by AEMO.

2 AEMO, *National transmission development plan*, June 2017, p23.

- A new interconnector linking South Australia with either New South Wales or Victoria from 2021.

- Augmenting the existing interconnector linking New South Wales with both Queensland and Victoria in the mid to late 2020s, particularly as coal-fired generation retires.

- A second Bass Strait interconnector from 2025, when combined with augmented interconnector capacity linking New South Wales identified above.

All three of the interconnector development options identified by AEMO as having positive market benefits are being explored by the relevant TNSPs. The TNSPs have initiated their own assessments to examine the viability of these development options and to explore whether alternative options could also deliver market benefits. The current and recent initiatives by the electricity market stakeholders to explore further interconnection for the NEM include the following:

- ElectraNet has initiated the South Australia Energy Transformation RIT-T with publication of the project specification consultation report (PSCR) in November 2016. The PSCR identified a non-network option and four interconnector options for further assessment, which include interconnection options for South Australia with Victoria, New South Wales and Queensland.

- Augmentations to the existing interconnectors linking New South Wales with Victoria and Queensland are being considered by AEMO and Powerlink respectively. AEMO identified that increasing the transfer capability of VIC-NSW interconnector is likely to be economically justifiable, with a pre-feasibility assessment for the project expected to be completed within a year. The AER has accepted Powerlink's proposal for QNI upgrade to be included as a contingent project in its 2017-22 regulatory control period.

- The feasibility of a second Tasmanian interconnector was assessed by a study initiated by the Commonwealth and Tasmanian Governments which published a final report in April 2017.[3] AEMO in its role as the national transmission planner is set to review the second Bass Strait interconnector as part of its least cost generator and transmission outlook, and its conclusion is expected to be reported in the 2017 NTNDP.

Background

The last resort planning power allows the Commission to direct one or more network service providers to apply the regulatory investment test for transmission to augmentation projects that are likely to relieve a forecast constraint on a national transmission flow path.

3 Commonwealth of Australia and Tasmanian Government, *Feasibility of a Second Tasmanian interconnector - Final Study*, April 2017

These flow paths include the infrastructure that allows electricity to be physically transferred across the NEM regional boundaries, known as interconnectors. Each interconnector will have a certain nominal 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 can cause the actual transfer capacity of an interconnector to be set at lower levels. For this reason, the Commission has regard to both the 'physical' interconnectors and to the transmission flow-paths and/or corridors leading up to the interconnectors when considering whether to exercise the last resort planning power.

Following on from this, 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 when other mechanisms to provide for the planning of this investment appear to have failed. Being a last resort mechanism, it is designed to only be utilised where there is a clear indication that regular planning processes have resulted in a planning gap regarding inter-regional transmission infrastructure. The Commission must exercise its power in accordance with requirements in the National Electricity Rules and the last resort planning power guidelines.[4]

The Commission is also required to report annually on the matters which it has considered during that year in deciding whether to exercise the last resort planning power. To date, the Commission has not exercised the last resort planning power.

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

Contents

1 Background and approach

1.1 Background

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

Responsibility for planning of the transmission network in the NEM is generally shared between the Australian Energy Market Operator (AEMO) in its role as National Transmission Planner and the transmission network service providers (TNSPs) in the NEM.[5] These responsibilities are complemented by the Australian Energy Market Commission's (Commission's) last resort planning power (LRPP).

The LRPP allows the Commission to direct one or more network service providers (NSPs) to apply the regulatory investment test for transmission (RIT-T) to augmentation projects that are likely to relieve a forecast constraint on a national transmission flow path.[6] These flow paths include the infrastructure that allows electricity to be physically transferred across the NEM regional boundaries, known as interconnectors.

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

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

Further information on the interconnection of the NEM and network constraints is provided in Appendix A of this report.

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

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

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

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

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

More detail on this approach can be found in the Commission's LRPP guidelines.[7]

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

2 Commission's considerations and conclusions

The Commission has concluded that TNSPs are adequately considering inter-regional transmission constraints in the NEM and has therefore decided not to exercise the LRPP in 2017 in accordance with the requirements in the NER.

In making this decision the Commission has considered:

- The 2016 National Transmission Network Development Plan (NTNDP) published by AEMO in December 2016 and the 2015 NTNDP published by AEMO in November 2015.[8]
- The 2017 transmission annual planning reports for each region of the NEM published by TNSPs.
- The NEM constraint report for 2016 published by AEMO.
- Relevant regulatory investment tests for transmission (RIT-T) reports for RIT-Ts that have recently been undertaken.

While both the 2015 and 2016 NTNDP have been considered, the Commission has given significantly more weight to the 2016 NTNDP as the constraints on the network forecast by AEMO in this report are based on more recent electricity demand and supply forecasts.

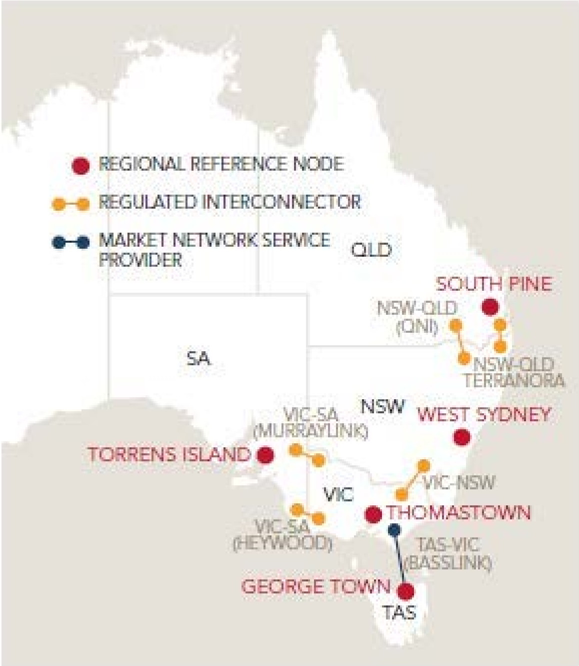
Table 2.1 below provides a summary of the analysis supporting the Commission's conclusion. In particular, it outlines the inter-regional network constraints identified by AEMO in the NTNDP and how the relevant TNSPs are planning to address these constraints.

Each interconnector will have a certain nominal 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 can cause the actual transfer capacity of an interconnector being set at lower levels. For this reason, the Commission has regard to both the 'physical' interconnectors and to the transmission flow-paths and/or corridors leading up to the interconnectors when considering whether to exercise the last resort planning power.

The physical location of each interconnector in the NEM is set out in Figure 2.1.

8 Note that there has been a change in the naming convention for the NTNDP year adopted by the LRPP review to align it with the naming convention used by AEMO.

Figure 2.1 Location of interconnectors in the NEM



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

Further details and analysis supporting the Commission's conclusion are contained in Appendices C to H of this report. In addition, Appendix B of this report provides a summary of the information in the planning reports considered by the Commission.

Table 2.1 Constraints relating to NEM interconnectors and TNSP projects addressing these constraints

Inter-connector	Constraint identified by AEMO in the NTNDP	TNSP Responsible	Project(s) identified by TNSP to address constraint and its status
QNI	Transmission limitations between 330 kV lines between Dumaresq and Liddell in Northern New South Wales. It is forecast to occur during periods with high imports from Queensland into New South Wales and high wind or Solar PV generation.	TransGrid	Project options for low, medium and high capacity upgrades have been identified to address the constraint. They include the following: • A low capacity upgrade that involves turning both transmission lines between Armidale and Dumaresq into a switching station in between them. A further upgrade would include turning both transmission lines from Dumaresq to Bulli Creek into a new switching station midway. • A medium capacity upgrade can be achieved by installation of a second SVC at Armidale, along with upgrades to 330 kV lines between Liddell and Tamworth to 120°C design temperature. • Another medium capacity upgrade option includes the following: installation of a second SVC at Dumaresq and Tamworth, upgrades to 330kV lines between Liddell and Tamworth to 120°C design temperature and installation of capacitor banks at Tamworth, Armidale and Dumaresq substations. • A new route diverse interconnector between New South Wales and Queensland is considered as the high capacity upgrade option. A project and its timing will be chosen upon evaluation of the economic benefits of the options.

<table>
<tr><th>Inter-connector</th><th>Constraint identified by AEMO in the NTNDP</th><th>TNSP Responsible</th><th>Project(s) identified by TNSP to address constraint and its status</th></tr>
<tr><td>QNI</td><td>Transmission limitations between 330 kV lines between Dumaresq and Bulli Creek (part of QNI) when transient stability limits, enforced by constraints equations, set the exporting limits from Queensland to New South Wales.</td><td>Powerlink</td><td>QNI upgrade is included as a contingent project in the Powerlink’s 2017-22 revenue determination. Project progression depends on its trigger events being reached, which include the completion of a successful RIT-T, demonstrating net market benefits associated with the project.

Powerlink is also undertaking several analysis projects to help identify the best approach forward for QNI capacity expansion.</td></tr>
<tr><td>VIC-NSW</td><td>Transmission limitations on the Sydney to Canberra/Yass 330 kV corridor during times with high wind and PV generation in Canberra and high export from Victoria to New South Wales.</td><td>TransGrid</td><td>Project options for low and high capacity upgrades have been identified to address the constraint. They respectively include:

• Upgrading the 330 kV lines between Yass to Marulan, Canberra to Yass, Kangaroo Valley to Dapto, Sydney West to Bannaby, Gullen Range to Bannaby and Yass to Gullen Range to meet a 120°C design temperature.

• Carrying out staged upgrades of the 330 kV lines between Bannaby to Sydney West (39) and Canberra to Upper Tumut (O1) to meet a 120°C design temperature, and Yass to Marulan (4 and 5) to meet a 100°C design temperature. Installing phase shifting transformers at Bannaby and Marulan substations, and construction of a new transmission line between Yass and Bannaby.

The decision to proceed on a project is contingent upon external outcomes such as the expansion of the Snowy Hydro Scheme.</td></tr>
</table>

Inter-connector	Constraint identified by AEMO in the NTNDP	TNSP Responsible	Project(s) identified by TNSP to address constraint and its status
VIC-NSW	Transmission limitation on South Morang 500/330 kV transformer. AEMO considers this is present when there is high export from Victoria to New South Wales.	AEMO	The following projects proposed under the emerging development opportunity to improve Victoria to New South Wales export capability may address the constraint: • installation of a new 500/300 kV transformer at South Morang • increasing the transient export limit, through network or non-network solutions. A project has not yet been commenced. AEMO will review the benefits on increasing the VIC-NSW interconnector capacity as part of the 2018 Victorian Annual Planning Report (VAPR), considering latest available information.
VIC-NSW	Transmission limitations on Dederang-South Morang 330 kV circuits. AEMO considers that this constraint is present when there is high transfer between Victoria and New South Wales (export or import).	AEMO	Projects proposed by AEMO under emerging development opportunity to improve Victoria to New South Wales export capability and augmentations proposed to address monitored limitations may relieve the constraint. The projects options include: • uprating of south Morang – Dederang 330 kV lines by conductor re-tensioning • increasing the transient export limit, through network or non-network solutions • uprating the two existing lines to 82 ºC (conductor temperature) operation and series compensation • installing a new (third) 330 kV, 1,060 MVA single circuit line between Dederang and South Morang with 50% series compensation. A project has not yet been commenced. AEMO will review the benefits on increasing the VIC-NSW interconnector capacity as part of the 2018 VAPR, considering latest available information.

Inter-connector	Constraint identified by AEMO in the NTNDP	TNSP Responsible	Project(s) identified by TNSP to address constraint and its status
VIC-NSW	Transmission limitations on Eildon-Thomastown 220 kV line. AEMO considers that this constraint is present when there is high import from New South Wales into Victoria.	AEMO	Projects proposed by AEMO under emerging development opportunity to improve New South Wales to Victoria import capability and augmentations proposed to address monitored limitations may relieve the constraint. The projects options include: • installing wind monitoring facilities on Dederang – Mount Beauty – Eildon – Thomastown 220 kV lines to increase transfer capabilities • implementing an automatic load shedding scheme to allow for operating the Dederang – Mount Beauty – Eildon – Thomastown 220 kV lines at a higher rating • uprating the Eildon-Thomastown 220kV line, including terminations to 75 ºC operation. A project has not been committed as yet. AEMO will review the benefits on increasing the VIC-NSW interconnector capacity as part of the 2018 VAPR, considering latest available information.
VIC-NSW	Transmission limitations on Dederang – Mt. Beauty 220 kV lines during periods of high export to New South Wales.	AEMO	Projects proposed by AEMO under emerging development opportunity to improve New South Wales to Victoria import capability and proposed augmentations to address monitored limitations may relieve the constraint. The outlined project include: • installing wind monitoring facilities on Dederang – Mount Beauty – Eildon – Thomastown 220 kV lines to increase transfer capabilities • implementing an automatic load shedding scheme to allow for operating the Dederang – Mount Beauty – Eildon – Thomastown 220 kV lines at a higher rating • uprating the conductor temperature of both 220 kV circuits between Dederang and Mt. Beauty to 82 ºC. A project has not been committed as yet. AEMO will review the benefits on increasing the VIC-NSW interconnector capacity as part of the 2018 VAPR, considering latest available information.

Inter-connector	Constraint identified by AEMO in the NTNDP	TNSP Responsible	Project(s) identified by TNSP to address constraint and its status
Heywood	Transmission limitations on the Tungkillo to Tailem Bend South East transmission corridor of South Australia. AEMO believes this issue will arise during high levels of wind and or solar generation in the Northern South Australia and Adelaide zones.	ElectraNet	ElectraNet identified two projects in its 2017 TAPR to address the forecast economic limitation. The outlined projects include: • populating an additional diameter at Tungkillo to connect the Tailem Bend to Cherry Gardens 275 kV line • construction of a new high capacity interconnector between South Australia and the eastern states as proposed under the South Australia Energy transformation RIT-T. The first project is included in ElectraNet's proposed network capability incentive parameter action plan (NCIPAP) for the 2018-19 to 2022-23 period, while a Project Specification Consultation Report (PSCR) for the RIT-T was published in November 2016.
Murraylink	Transmission limitations are forecast on the 132 kV network in the Riverland region of South Australia. AEMO considers this issue will arise during high levels of wind and/ or solar generation in the Northern South Australia zone and high Murraylink export to Victoria.	ElectraNet	ElectraNet identified two projects in its 2017 TAPR to address the forecast potential economic limitation. The outlined projects include: • uprating of the Robertstown to North West Bend No. 2 132 kV line and the North West Bend to Monash No. 2 132 kV line from 80°C to design clearances to 100°C design clearances • construction of a new high capacity interconnector between South Australia and the eastern states as proposed under the South Australia Energy Transformation RIT-T. The first project is already committed and included in ElectraNet's NCIPAP, while a PSCR for the RIT-T was published in November 2016.
Basslink	Transmission limitations on the George Town – Sheffield 220 kV line during periods of high wind generation from the North West and West Tasmania area and, high Basslink export from Tasmania to Victoria.	TasNetworks	TasNetworks has outlined in its 2017 TAPR that it is aware of the issue and has since informed the Commission that it is preparing a strategic plan for transmission capacity in north west Tasmania. It will consider the constraints on George Town to Sheffield 220 kV lines, as well as other lines in the region. Further details of this plan are expected in TasNetworks's upcoming annual planning reports.

Inter-connector	Constraint identified by AEMO in the NTNDP	TNSP Responsible	Project(s) identified by TNSP to address constraint and its status
Basslink	Voltage collapse at George Town when there is high export from Tasmania to Victoria with no gas powered generation units on line in Tamar Valley and reduced number of hydro units in northern Tasmania.	TasNetworks	TasNetworks plans to address the voltage collapse at George Town with the following augmentation project: • Installation a new 40 MVAr 110 kV capacitor bank at George Town substation to facilitate reactive power compensation. The capacitor bank upgrade is expected to be operational by March 2018. Dynamic reactive support will also be required to assist with this issue.
Basslink	Transient over-voltage at George Town when there is high export from Tasmania to Victoria with no gas powered generation units on line in Tamar Valley and reduced number of hydro units in northern Tasmania.	TasNetworks	TasNetworks outlined in its TAPR that it is aware of the issue and has since informed the Commission of its intention to include following proposed project in its next revenue proposal: • Installation of a 50 MVAr STATCOM at George Town. TasNetworks's final revenue proposal for the next period is will be submitted to the AER by January 2018.
Basslink	Basslink inverter commutation instability due to low fault level at George Town.	TasNetworks	TasNetworks outlined in its TAPR that it is aware of the issue and has since informed the Commission that the issue will be managed through implementation of constraint equations. TasNetworks is considering a contracting arrangement with a Tasmanian generator to alleviate the constraints. Analysis will need to be carried out to assess the benefits of addressing the constraint.
Basslink	High rate of change of frequency for Tasmania when there is high wind generation in Tasmania and or increased import from Victoria to Tasmania and reduced Tasmanian hydro units on line.	TasNetworks	TasNetworks outlined in its TAPR that it is aware of the issue and has since informed the Commission that the issue will be managed through implementation of constraint equations.

Inter-connector	Constraint identified by AEMO in the NTNDP	TNSP Responsible	Project(s) identified by TNSP to address constraint and its status
Basslink	High rate of change of frequency for Tasmania when there is unavailability of existing (FCAS) with the retirement of smelters in Tasmania.	TasNetworks	TasNetworks outlined in its TAPR that it is aware of the issue and has since informed the Commission that the issue will be managed through implementation of constraint equations.

Abbreviations

AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
IC	Interconnector
LRPP	Last resort planning power
MVAr	Mega volt amps (reactive)
NCIPAP	Network capability incentive parameter action plan
NEM	National electricity market
NEMDE	National electricity market dispatch engine
NER	National Electricity Rules
NTNDP	National Transmission Network Development Plan
PV	Photovoltaic (Solar)
QNI	Queensland–New South Wales interconnector
RIT-T	Regulatory investment test for transmission
TAPR	Transmission annual planning report
TNSP	Transmission network service provider
VAPR	Victorian annual planning report

A Interconnection and constraints

A.1 Interconnection

Almost 40,000 km of transmission lines and associated infrastructure make up the physically interconnected NEM transmission network.[9]

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:[10]

- 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
- allows optimisation of investment in generation and transmission as interconnection may defer the need for investment in generation or intra-regional transmission which may otherwise have taken place.

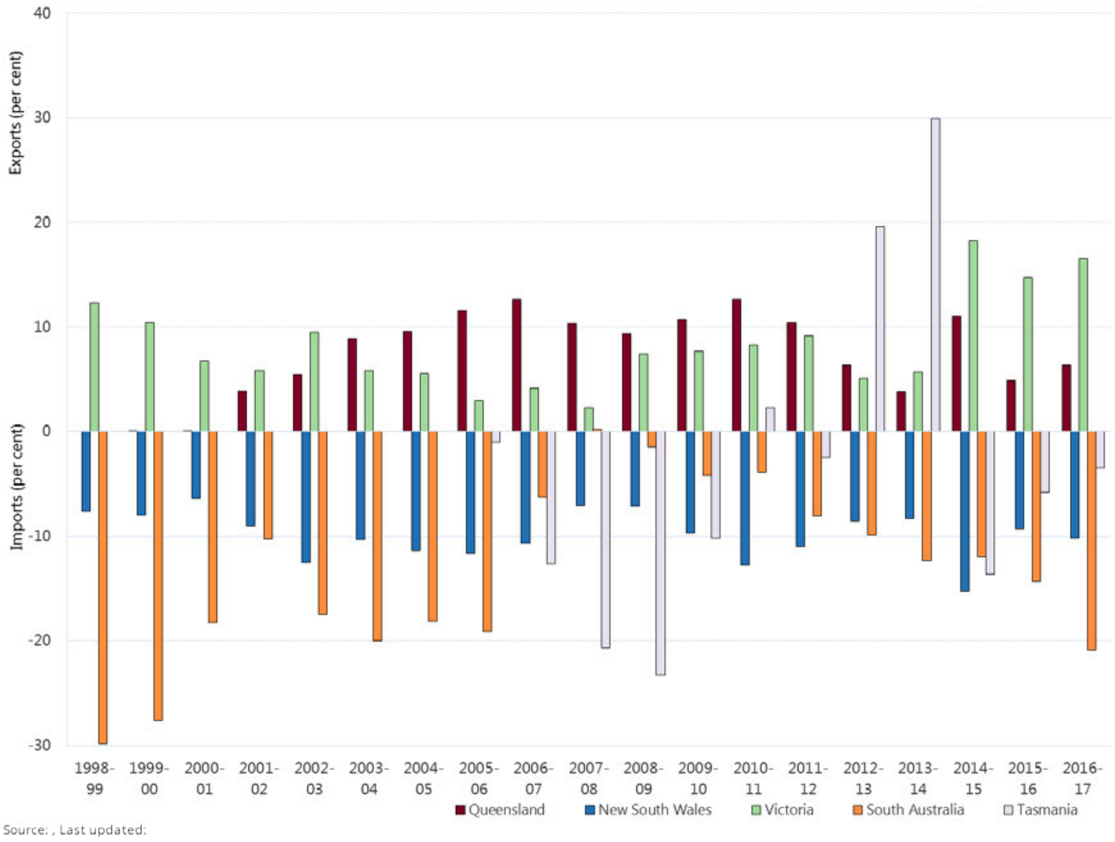
Interconnection also contributes to reliability of supply across the NEM as regions can draw upon a wider pool of reserves.

The level of interconnection in the NEM has facilitated inter-regional trade between NEM regions. Depending on local circumstances - such as available generation, the cost of generation and levels of demand - regions are either net importers or net exporters of electricity. Figure A.1 expresses inter-regional trade in net flows as a percentage of regional energy demand for each region of the NEM.

9 AEMO 2016, AEMO Melbourne, www.aemo.com.au/Electricity/National-Electricity-Market-NEM, viewed 30 August 2017.

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

Figure A.1 **Annual interregional trade, in net flows, as a percentage of regional electricity consumption**



Source: Industry statistics on the Australian Energy Regulator website. Available from www.aer.gov.au/industry-information/industry-statistics, last viewed 30 August 2017.

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

- Sources of renewable energy are often further removed from centres of demand than conventional generation.
- The potential to exploit the geographic diversity of intermittent generation sources, which may lead to more efficient generation siting decisions, and smoothing of the intermittency in aggregate across the NEM.
- The potential for price separation between regions is likely to increase as a result of lower-cost renewable energy in some regions
- The intermittence of renewable energy sources such as wind and solar requires sufficient dispatchable generation from other power sources in order to facilitate a reliable power supply. This dispatchable generation may be provided by a generator in another region

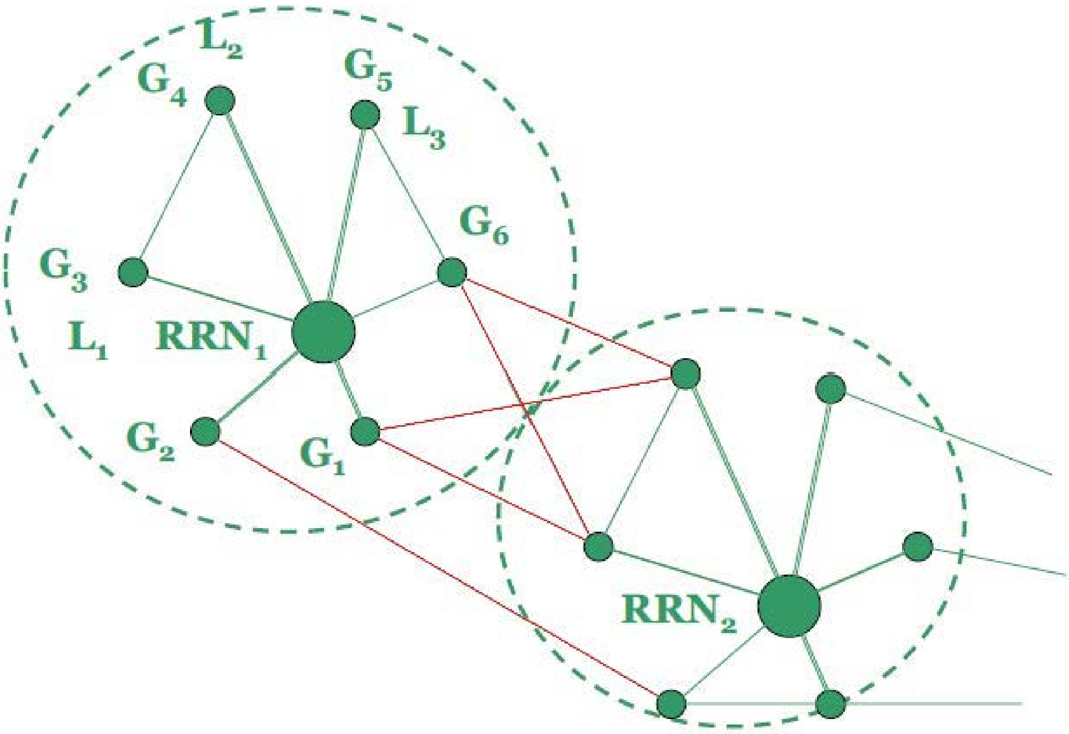
A.2 Interconnectors

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 generally own and operate the transmission network in their NEM regions and are responsible for ensuring the network is able to operate with sufficient capability by planning and carrying out the needed augmentations. These businesses also need to comply with transmission reliability and system security requirements which guide how they plan and operate their networks.

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

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

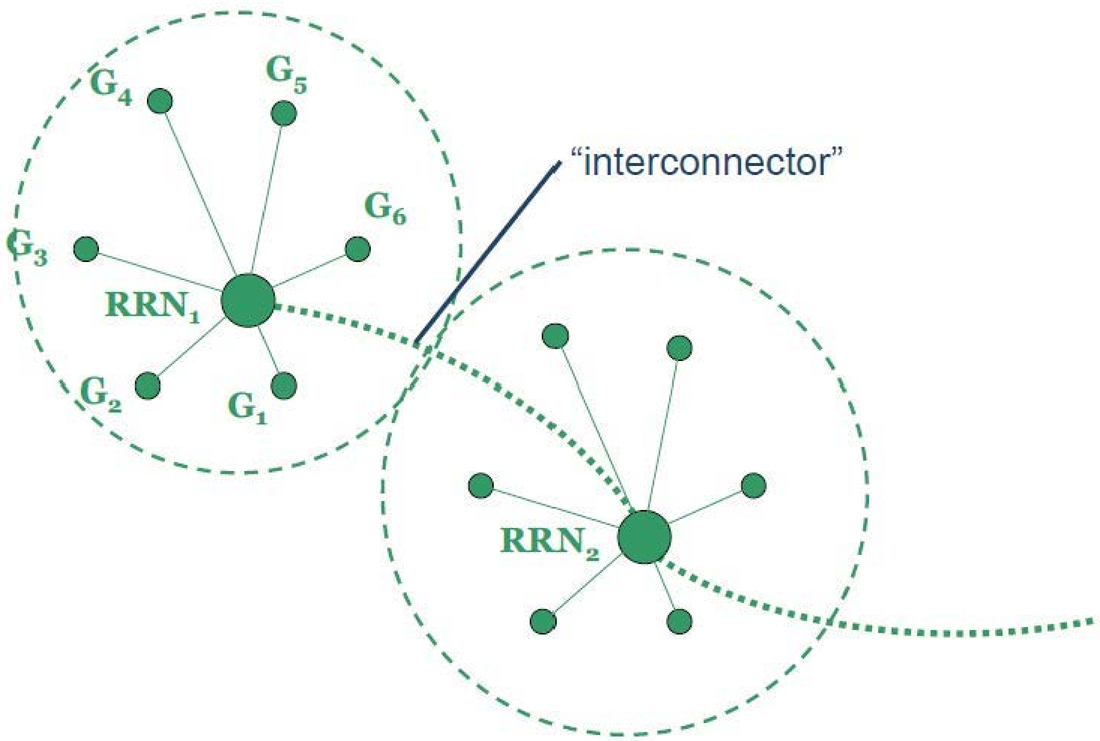


Note: 'RRN' refers to regional reference node, 'G' to generator and 'L' to load (demand) centres. The red lines represent the physical interconnectors connecting the regions.

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

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

Figure A.3 Treatment of interconnectors for market purposes



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

There are two types of interconnectors in the NEM: regulated and market (or unregulated) interconnectors.[11]

A regulated interconnector is an interconnector that forms part of a TNSP's regulated asset base as it is used by the TNSP to provide prescribed transmission services to customers. The TNSP owning the interconnector includes the value of its interconnector assets in its regulatory asset base and its maximum annual revenue set by the Australian Energy Regulator includes a return on those assets. The revenue is collected by distribution network service providers as part of the network charges levied on retailers. Generally, a TNSP is required to undertake a regulatory investment

11 AEMO 2016, AEMO, Melbourne, viewed 20 September 2017, https://www.aemo.com.au/Datasource/Archives/Archive1027.

test for transmission (RIT-T) when planning for the building of a new regulated interconnector or increasing the capacity of an existing regulated interconnector.[12]

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

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

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

Table A.1 Interconnectors in the NEM

Name	Region	Regulated or market[13]
QNI	Between Queensland and New South Wales	Regulated
Terranora (Directlink)	Between Queensland and New South Wales	Regulated
VIC-NSW	Between Victoria and New South Wales	Regulated
Heywood	Between South Australia and Victoria	Regulated
Murraylink	Between South Australia and Victoria	Regulated
Basslink	Between Tasmania and Victoria	Market

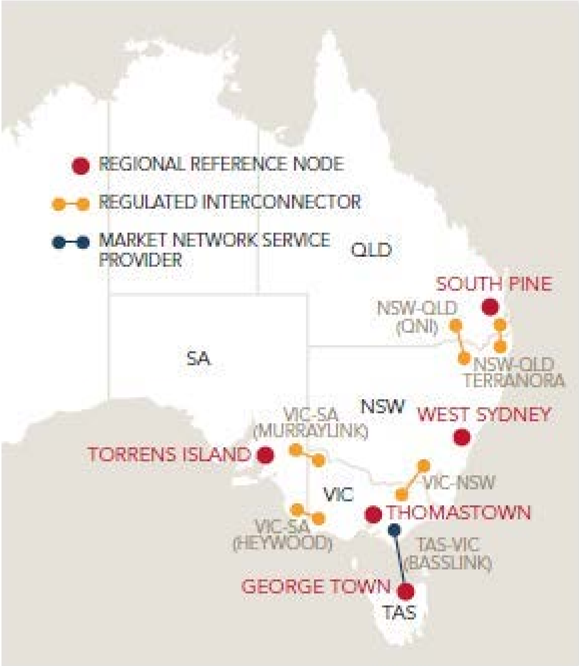
Source: AEMO website, www.aemo.com.au/Datasource/Archives/Archive1027, viewed 30 September 2016.

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

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

13 Market interconnectors are unregulated.

Figure A.4 Location of interconnectors in the NEM



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

A.3 Network constraints

The ability of the network to carry electricity (the 'transfer capability') is in practice affected by a range of factors.[14]

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

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

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

Congestion is a normal feature of power systems and occurs because there are physical limits, needed to maintain the power system in a secure operating state. These include limits imposed by:

- 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.
- Stability limits: these include limits to keep the NEM generating units operating synchronously and in a stable manner (for example within design tolerances for voltage), and transmission elements operating in a stable manner.

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

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

A.4 Constraints and the dispatch process

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

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

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

Box A.1 Constraint equations

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

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

For example, a constraint of the form:

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

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

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

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

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

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

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

As a general rule, constraint set equations names identify:

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

- the system condition ('outage ID').

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

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

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

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

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

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

- Augmentations to the transmission infrastructure, called 'network options'.[15]
- Solutions such as demand-side management and network support control ancillary services,[16] which may reduce the strain on transmission infrastructure elements during certain periods, thereby assisting in maintaining operation of this infrastructure within its physical limits. These solutions are termed 'non-network options'.

A.5 The effect of network constraints

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

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

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

16 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.[17]

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

Box A.2 Congestion and inter-regional settlement residues[18]

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

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

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

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

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

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

in the importing region (the low-priced region). As a result, inter-regional settlement residues can be negative. The cost of funding these negative settlement residues is ultimately borne by consumers in the importing region.[19]

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

B Planning reports considered by the Commission

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

B.1 National Transmission Network Development Plans for 2015 and 2016

This section sets out:

- general information on the National Transmission Network Development Plan (NTNDP)
- a summary of the forecast scenarios used in the NTNDP for 2016 which is relevant to the analysis that follows in Appendices C to H.

B.1.1 General information

The NTNDP provides a strategic and long term view of the development of the national transmission system under a range of market development scenarios over the next 20 years. It is concerned with modelling the development of the critical national transmission flow paths, that is, those areas of the transmission network connecting major generation or demand centres.

The NTNDP seeks to influence transmission investment by:

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

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

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

Figure B.1 National transmission zones and flow paths

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

Source: AEMO, *Planning methodology and input assumptions*, 30 January 2014, p5.

B.1.2 2016 NTNDP

As required by the NER, the Commission considers the NTNDP for the current and previous year when considering whether to exercise the LRPP.[20] The relevant NTNDPs are therefore the 2015 NTNDP which was published by AEMO in November 2015 and the 2016 NTNDP which was published by AEMO in December 2016.[21] While both NTNDPs were considered, the Commission has given significantly more weight to the 2016 NTNDP in its consideration of whether to exercise the LRPP as the investment needs identified by AEMO in this report are based on more recent electricity demand and supply forecasts.

The 2016 NTNDP outlined the trends and drivers likely to impact the development of the transmission networks over the forecast period of 20 years. It identified demand to be no longer be a driver for transmission development while the ageing coal generation fleet, emissions reduction policies and future customers investment trends were identified as the new drivers.

20 NER clause 5.22(f)(2).

21 Note that there has been a change in the naming convention for the NTNDP year adopted by the LRPP review to align it with the naming convention used by AEMO.

The 2016 NTNDP also outlined credible scenarios that reflect changes that are likely to impact the use, operation and development of transmission networks. These scenarios are the basis for the market modelling work carried out as part of the NTNDP development process which provides the forecast constraints on the transmission network. In the 2016 NTNDP, AEMO considered three scenarios for forecasting constraints including:[22]

- **Neutral:** This is the base case scenario considered as the most likely estimate for demand growth.

- **Low Grid Demand:** This scenario considers a different, credible path to test how the low boundary for demand (falling 32% in 20 years) could impact transmission development.

- **45% Emissions Reduction:** This scenario considers an accelerated emissions reduction trajectory towards 2030, based on neutral level of demand. It seeks to understand the sensitivity of strategic transmission grid development to a more accelerated transformation of the generation mix.

The three scenarios, together with sensitivities, are set out below in Table B.1

Table B.1 Scenarios and sensitivities in the NTNDP for 2017

Driver	NTNDP Neutral	NTNDP Low Grid Demand	NTNDP 45% Emissions Reduction
Population growth	ABS projection B	ABS projection C	ABS projection B
Economic growth	Neutral	Weak	Neutral
Consumer confidence	Average confidence and engagement	Low confidence and engagement	Average confidence and engagement
Rooftop PV and battery storage uptake	Neutral consumer in a neutral economy	Confident consumer in a weak economy	Neutral consumer in a neutral economy
Energy efficiency uptake	Medium	High	Medium
Emissions reduction requirement	Reduce greenhouse gas emissions by 28% below 2005 levels by 2030, with the resultant trajectory continued to 2036	Reduce greenhouse gas emissions by 28% below 2005 levels by 2030, with resultant the trajectory continued to 2036	Reduce greenhouse gas emissions by 45% below 2005 levels by 2030, with the resultant trajectory continued to 2036

Source: AEMO, *National Transmission Network Development Plan*, December 2016, p21.

22 AEMO, *National Transmission Network Development Plan*, November 2015, p10.

Further details on the planning methodology and input assumptions used in the NTNDP for 2017 are published in AEMO's NTNDP for 2017.[23]

B.2 The NEM constraint report for 2016

The NEM constraint report published annually by AEMO contains details about constraint equation performance in the preceding calendar year.[24] It also provides information on the drivers of constraint equation changes, analysis of binding and violating constraint equations, market impact of constraint equations and those equations that set interconnector limits. The relevant NEM constraint report for the 2017 LRPP review is the NEM constraint report for 2016 published by AEMO in June 2017.[25]

For the purpose of consideration of the LRPP, the Commission has analysed the 'system normal'[26] constraints that were most binding on interconnector limits, in terms of the number of hours, in each direction. The top three binding constraints in each direction for each interconnector are outlined in the analysis on the individual interconnectors in Appendices C to H of this report.

In addition to those equations setting interconnector limits, constraints can also be listed according to their market impact. The market impact value seeks to quantify, in dollar value, the impact of a particular constraint.[27] The top three market impacts for each interconnector from the NEM constraint report for 2016 in each direction is also outlined in the analysis on the individual interconnectors in Appendices C to H of this report.

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

23 AEMO, *National Transmission Network Development Plan*, November 2015, p10.

24 See for example, AEMO, *NEM constraint report 2016*, June 2017.

25 AEMO, *NEM constraint report 2016*, June 2017.

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

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

B.3 2017 transmission annual planning reports

By 1 July each year, each TNSP must publish an annual planning report.[28] This report must set out the outcomes of a TNSPs' annual planning review which a TNSP is required to conduct under the NER.[29] The annual planning review involves a TNSP analysing the expected future operation of its transmission network, taking account of forecast future demand and generation, demand-side and transmission developments and other relevant data.[30] In addition, a TNSP must consider the potential for network augmentations or non-network alternatives to augmentations when conducting an annual planning review.[31]

Importantly, TNSPs are also required to take the most recent NTNDP into account when conducting their annual planning review.[32] In particular, when a TNSP proposes augmentations to the network, it must explain in its annual planning report how the proposed augmentations relate to the most recent NTNDP and the development strategies for current or potential national transmission flow paths specified in the NTNDP.[33] This provides coordination between the planning priorities identified by AEMO in the NTNDP regarding inter-regional flow paths and the planning activities undertaken by TNSPs for each jurisdiction. In addition to inter-regional flow paths, the TNSPs will typically also consider upgrades that primarily affect transmission flow paths within their regions.

The minimum forward planning period for the annual planning review and therefore that covered by the annual planning report is ten years.[34] The relevant transmission annual planning reports for the 2017 LRPP review are those published in June 2017.

B.4 Regulatory investment test reports

The NER require that TNSPs must apply a regulatory investment test for transmission (RIT-T) for any projects with an estimated cost of more than $6 million.[35]. This requirement now covers both augmentation and replacement expenditure.[36]

The purpose of the RIT-T is to identify the transmission investment option that maximises the net economic benefit to all those who produce, consume and transport

28 NER clause 5.12.2(a).

29 NER clause 5.12.1(b).

30 NER clause 5.12.1(a).

31 NER clause 5.12.1(b)(4).

32 NER clause 5.12.1(b)(3).

33 NER clause 5.12.2(c)(6).

34 NER clause 5.12.1(c).

35 The application of the regulatory investment test for transmission is also subject to a number of exceptions under clause 5.16.3(a) of the NER. The threshold increased to $6 million on 1 January 2016 as a result of a cost thresholds review final determination made by the Australian Energy Regulator on 5 November 2015.

36 AEMC, *National electricity amendment (replacement expenditure planning arrangement) rule 2017*, *Final* rule determination, 18 July 2017, Sydney.

electricity in the market, after performing cost-benefit analysis on a number of credible options.[37] The NER define a 'credible option' as an option or group of options that:

- address the identified need
- is, or are, commercially and technically feasible
- can be implemented in sufficient time to meet the identified need.[38]

The costs associated with options for transmission augmentation must be weighed against the benefits they are likely to bring to the market. Investments may be undertaken to either meet reliability standards or to deliver a net market benefit, for example, economic expansion.[39]

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

- changes in fuel consumption arising through different patterns of generation dispatch
- changes in the costs for parties, other than the transmission proponent, due to:
    - differences in the timing of new plant
    - differences in capital costs
    - differences in operating and maintenance costs
- changes in network losses
- changes in ancillary service costs
- competition benefits.[40]

The procedure that a proponent must follow in conducting a regulatory investment test is also outlined in the NER.[41] The AER has also developed the RIT-T application guidelines that provide guidance on the operation and application of the RIT-T.[42] Following completion of the regulatory investment procedure a project assessment conclusions report is published.

37 NER clause 5.16.1.

38 NER clause 5.15.2.

39 NER clause 5.16.1(c).

40 NER clause 5.16.1(c)(4).

41 NER clause 5.16.4.

42 AER, *Regulatory investment test for transmission application guidelines,* September 2017

C Review of the Queensland–New South Wales interconnector

All transmission network constraints on the Queensland–New South Wales interconnector are being addressed by the relevant TNSPs in their transmission annual planning reports. Similarly, all network constraints in the main transmission corridors around the interconnector in Queensland and New South Wales are being addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a TNSP under its last resort planning power.

This section provides the Commission's analysis of whether there are any constraints impacting the Queensland-New South Wales interconnector (QNI) that are not being addressed by the relevant TNSPs. It includes:

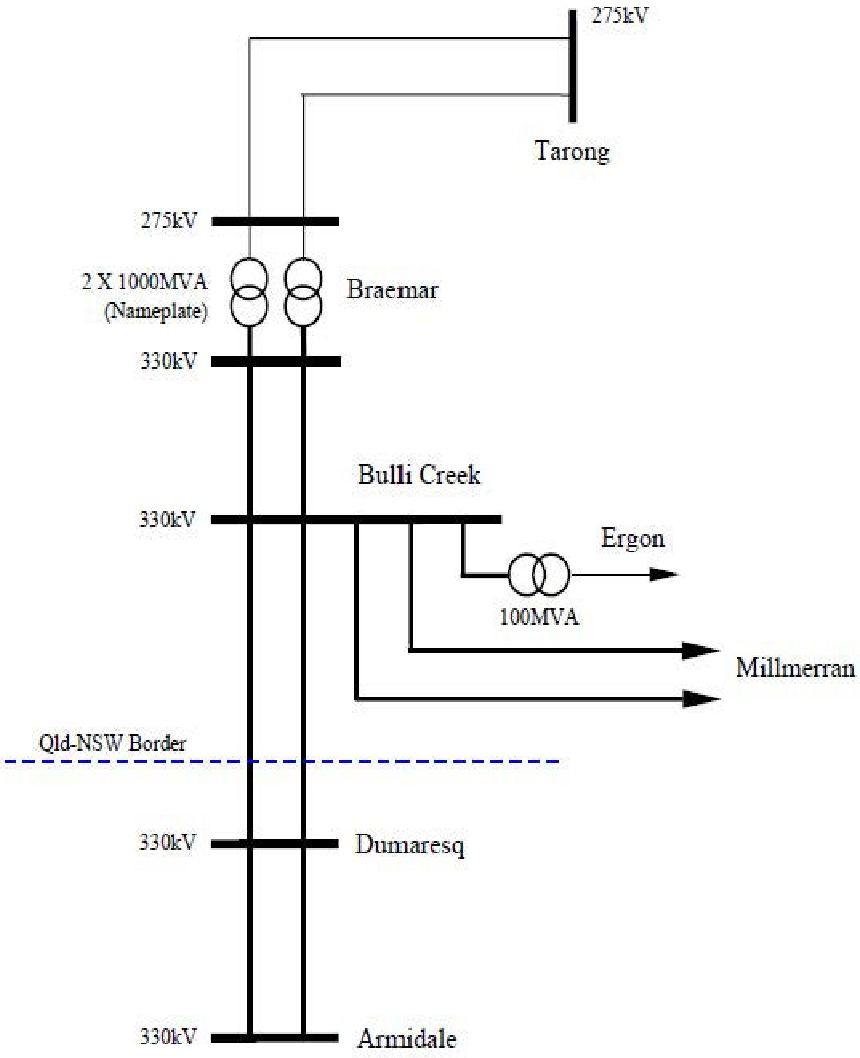
- an overview of the Queensland–New South Wales interconnector
- a review of the binding constraint equations that most often set the limits on the QNI interconnector from AEMO's NEM constraint report for 2016
- a review of the emerging transmission network constraints affecting this interconnector from the 2016 NTNDP
- a review of TransGrid and Powerlink's 2017 transmission annual planning reports on projects to address limitations to the interconnector and the main transmission corridors
- a summary of the projects identified to reduce transmission network constraints.

C.1 Overview of Queensland–New South Wales interconnector

The Queensland–New South Wales interconnector (QNI) connects the South West Queensland zone with the Northern New South Wales zone. It is a 330 kV alternating current double circuit interconnection that runs between Bulli Creek in Queensland and Dumaresq in New South Wales as set out in Figure C.1.[43]

[43] AEMO, *Interconnector Capabilities*, September 2015, p7.

Figure C.1 Queensland–New South Wales interconnector



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

The South West Queensland zone has a high installed generation capacity. The northern New South Wales zone does not have major generation sources, so the zone is a net importer and serves as a corridor of power flows between Queensland (both QNI and Terranora) and the rest of New South Wales.

The flow on QNI is normally from Queensland into New South Wales. However, at times of high generation in New South Wales or low generation in Queensland, the flow can reverse and go from New South Wales to Queensland. Due to their close electrical proximity to the New South Wales side, both QNI and Terranora often appear on the left hand side of constraint equations.[44]

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

C.2 Findings from the NEM constraint report for 2016

In its NEM constraint report for 2016, AEMO outlined the major constraints affecting the transfer of electricity between New South Wales to Queensland via the QNI interconnector. Transfers from New South Wales to Queensland are mainly limited by the system normal constraint equations for the voltage collapse on loss of the largest Queensland generating unit (Kogan Creek) or trip of the Liddell to Muswellbrook 330 kV line in New South Wales.[45]

The transfer from Queensland to New South Wales is normally limited by the transient stability limits for a two-line to ground fault between Armidale and Bulli Creek, or by frequency control ancillary services (FCAS) requirements for outages of lines between Bulli Creek and Liddell.[46]

Historically, most of the time flows were from Queensland into New South Wales at levels above 500 MW. However in 2016, the observed electricity flows through the QNI were predominately at lower levels ranging from 50MW to 350MW, still in the Queensland to New South Wales direction. Compared to 2015, there was a large increase in flows from New South Wales to Queensland, with the largest number of interconnector flow hours observed at approximately 200 MW.

In 2016, the flows on QNI interconnector were also the most constrained in the New South Wales to Queensland direction between the flow levels of 150 MW to 300 MW.[47]

The top three most binding system normal constraints that affected flows on QNI in both directions for 2016 are provided in Table C.1.

Table C.1 Binding constraint equations setting the QNI limits in 2016 (system normal)

New South Wales to Queensland limits			
Equation ID	**Hours binding in 2016**	**Description**	**Market impact (with position in top ten system normal market impacts per region)[a]**
N^^Q_NIL_B1, 2, 3, 4, 5, 6 & N^Q_NIL_B (This constraint was also identified on the Terranora (Directlink) interconnector)	572	To avoid voltage collapse for the loss of the largest Queensland generator	$ 466,661 (number one in top ten constraints with a market impact in New South Wales)

45 AEMO, *NEM constraint report 2016*, June 2017, p25.

46 ibid, p26.

47 ibid.

N^Q_NIL_A (This constraint was also identified on the Terranora (Directlink) interconnector)	79.3	To avoid overloading Liddell to Muswellbrook 330 kV line	$241,714 (number three in top ten constraints with a market impact in New South Wales)
N>>N-NIL__3_OPENED (This constraint was also identified on the Terranora (Directlink) interconnector)	60	To avoid overloading of Liddell to Muswellbrook (83) 330kV line on trip of Liddell to Tamworth (84) 330 kV line	$288,656 (number two in top ten constraints with a market impact in New South Wales)
Queensland to New South Wales limits			
V::N_NIL_xxx (This constraint was also identified on the VIC-NSW, Heywood, Murraylink and Basslink interconnectors).	97.2	To avoid transient instability for fault and trip of a Hazelwood to South Morang 500 kV line	$238,531 (number four in top ten constraints with a market impact in Victoria)
Q:N_NIL_AR_2L-G	61.1	To avoid transient instability for a two line to ground fault at Armidale	$130,743 (number two in top ten constraints with a market impact in Queensland)
N>>N-NIL__S	1.1	To avoid overloading Mt Piper to Wallerawang (70) 330 kV line on trip of Mt Piper to Wallerawang (71) 330 kV line	$50,793 (number five in the top ten constraints with a market impact in New South Wales)

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

Source: AEMO, *NEM constraint report 2016*, June 2017 and *NEM constraint report 2016 supplementary data*, June 2017.

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

C.3.1 Findings from the 2016 NTNDP

The 2016 NTNDP by AEMO identified two forecast economic dispatch limitations in its forecast period of up to 2035-36 that were deemed relevant for the QNI interconnector.[48] One of these limitations is forecast for the Northern New South Wales zone whilst the other is forecast for the south west Queensland NTNDP zone.[49] Reliability limitations were also identified for the New South Wales and Queensland regions but their assessment did not identify them to be impacting the QNI interconnector.

The NTNDP identified transmission limitations on the 330 kV lines between Dumaresq and Liddell for the northern New South Wales zone. The limitation is forecast to eventuate during periods with high imports from Queensland into New South Wales and high wind or Solar PV generation, under all the modelling scenarios. [50]

The second forecast economic dispatch limitation involves transmission limitations on the 330kV lines between Dumaresq and Bulli creek, impacting part of QNI interconnection. It is expected to be experienced when transient stability limits, enforced by constraints equations, set the exporting limits from Queensland to New South Wales. The constraint is forecast under neutral and low grid demand scenarios and is reported under the NTNDP to be in the South West Queensland zone.[51]

C.3.2 Findings from TransGrid's New South Wales transmission annual planning report 2017

In its 2017 transmission annual planning report (TAPR), TransGrid has identified several possible network development plans to address the emerging constraints and to support the connection of new renewable generation to its network. Among the proposed major developments is the reinforcement of the North-Western New South Wales network, which is relevant for the NTNDP forecast limitation in the Northern New South Wales zone. The reinforcement is to be achieved by increasing the transmission capacity north of Liddell and the transfer capacity of QNI. Project options for a low, medium and high capacity upgrade have been identified, as described below: [52]

- The low capacity option includes turning both transmission lines between Armidale and Dumaresq into a switching station in between them, in order to provide an additional 20 MW transfer capacity. Turning both transmission lines into a switching station midway will have the effect of reducing the overall path impedance when a line trips due to a fault, which will effectively increase the QNI transient stability limit. A further upgrade could be achieved by turning both transmission lines from Dumaresq to Bulli Creek into a new switching station midway between these substations. The combination of both upgrades would provide a total of 86 MW in increased transfer capacity. [53]

48 AEMO, *National transmission network development plan,* December 2016, pp37-38.

49 Ibid.

50 Ibid, p37.

51 AEMO, *National Transmission Network Development Plan, December 2016,* p38.

52 TransGrid, *NSW transmission annual planning report 2017*, June *2017,* p25

53 Ibid.

- A medium capacity upgrade can be achieved by installation of a second SVC at Armidale, along with upgrades to the 300 kV lines between Liddell and Tamworth to 120°C design temperature. This option can increase the New South Wales to Queensland export capability by 300 MW and import capability by 50 MW.

- Another medium capacity upgrade option includes the installation of SVCs at Dumaresq and Tamworth and upgrades of lines 83, 84 and 88 to 120°C design temperature, and installation of capacitor banks at Tamworth, Armidale and Dumaresq substations. This option can increase interconnector exports capability from New South Wales to Queensland by 460 MW and import capability by 190 MW. [54]

- A new route diverse interconnector between New South Wales and Queensland is considered as the high capacity upgrade option. This option will allow sharing of over 1,000 MW of power between New South Wales and Queensland. This option also includes opening of a new renewable energy precinct of over 2,000 MW and will allow sharing of inertia between states.

The network augmentation options outlined above are subject to evaluation of economic benefits. A project is expected to be initiated with the timing, determined by the economic evaluation. The project may be staged if required, to maximise economic benefits.[55]

TransGrid's TAPR also outlined a minor planned project to improve the QNI transfer capability. The project involves installation of a transfer tripping scheme for the 132 kV capacitor bank at Armidale, to improve the QNI transfer capability during outage of an Armidale 330/132 kV transformer. The project's planned date is by June 2023 and it is expected to cost approximately $200,000. [56]

Thus, TransGrid has addressed the forecast economic limitation in its jurisdiction impacting the QNI interconnector, by identifying several projects that are likely to facilitate increased transfer capacities across the QNI interconnector and transmission flow paths leading up to it.

C.3.3 Findings from Powerlink's 2017 transmission annual planning report for Queensland

In its 2017 Transmission Annual Planning Report (TAPR), Powerlink outlined that it did not anticipate undertaking any significant augmentation works in the current outlook period, with the exception of those included in its revenue determination as potential contingent projects.[57]

54 TransGrid, *NSW transmission annual planning report 2017*, June *2017*, p25

55 Ibid.

56 Ibid p32.

57 Powerlink, *Transmission annual planning report 2017,* June 2017, p56.

Powerlink proposed the QNI upgrade to be included as a contingent project in its revenue determination. The identified network option included establishing controllable series compensation for the interconnection. The AER has since accepted the QNI upgrade as a contingent project in Powerlink's 2017-22 regulatory control period, which may address the forecast transmission constraint between Dumaresq and Bulli creek.[58] Powerlink identified three trigger events that need to be reached for the upgrade to proceed. One of the trigger events includes the successful completion of a RIT-T, demonstrating network investment maximises net market benefits.

Since the publication of its TAPR, Powerlink has also provided an update to the Commission regarding its initiatives that are relevant to addressing the forecast limitation on the QNI interconnector. According to the update, Powerlink is currently in the process of assessing the impacts of a changing generation mix for its transmission network. Analysis is also being undertaken to identify further the economic case for QNI expansion, whilst taking into account the broader context of a changing generation mix. [59]

Powerlink has initiated several analysis work streams that help inform the best approach forward to address the forecast QNI limitation. There are several relevant analysis work streams being undertaken as described below: [60]

- Powerlink is contributing to the South Australia Energy Transformation RIT-T. One of the options being assessed in the RIT-T is the development of a High Voltage Direct Current – Voltage Source Converter (HVDC-VSC) connection between South West Queensland and South Australia. Powerlink has carried out analysis to confirm that this option also has the potential of increasing the current QNI limit through implementation of a special control schemes with the HVDC-VSC link. The assessment identified possible increases of up to 300 MW for QNI.

- Powerlink has engaged the services of a consultant to investigate the impact that expanding renewable generation in north Queensland may have on its transmission network's performance, the QNI interconnector and emergence of congestion.

- Joint planning discussion between Powerlink and TransGrid, to identify viable network options for QNI capacity upgrade. Powerlink is currently in the process of updating the cost estimates for several of the network options identified in the 2014 RIT-T.

- Powerlink is also engaging with AEMO for the development of an integrated grid plan to facilitate the efficient development and connection of renewable energy zones across the NEM. The development of this plan is in response to Finkel review's recommendation 5.1.[61]

58 Powerlink, *Transmission annual planning report 2017,* June 2017, p130.

59 Powerlink confirmed this by email on 25 September 2017.

60 Ibid,

61 The recommendation states that by mid-2018, the Australian Energy Market Operator, supported by transmission network service providers and relevant stakeholders, should develop an integrated

In summary, the AER has accepted the QNI upgrade as a potential contingent project in Powerlink's revenue determination. Powerlink has also initiated several streams of analysis to identify the best approach forward for QNI capacity expansion. Thus, Powerlink has outlined plans to address the forecast limitation on the QNI interconnector.

C.4 Summary of projects for identified network constraints

There were two forecast economic limitations relevant for QNI, which were identified by the NTNDP. The constraints impacting QNI and the transmission corridors around QNI in Queensland and New South Wales are being adequately addressed by the relevant TNSPs. The TNSPs' plans to address the constraints were outlined in the transmission annual planning report and communicated to the Commission. Table C.2 provides a summary of identified constraints and plans outlined by TNSPs to deal with them.

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

Report limitation identified	Details of constraint identified	Project to address constraint	Project status
2016 NTNDP (economic constraint)	Transmission limitations on the 330 kV lines between Dumaresq and Liddell during periods with high imports from Queensland into New South Wales and high wind or Solar PV generation	Low, medium and high capacity upgrade options identified, including: • Turning lines into switching stations between substations • SVCs at substations and increases to line design temperatures • New route interconnector between New South Wales and Queensland (TransGrid)	Contingent evaluation of economic benefits
2016 NTNDP (economic constraint)	Transmission limitations on the 330kV lines between Dumaresq and Bulli creek when transient stability limits, enforced by constraints equations, set the	QNI upgrade has been accepted as a contingent project in Powerlink's 2017-22 revenue determination. Several analysis projects are underway to identify the best approach forward for QNI capacity expansion (Powerlink)	The contingent project has three triggers that need to be reached for the project to proceed. One of the triggers is the successful completion of a

grid plan to facilitate the efficient development and connection of renewable energy zones across the National Electricity Market.

Report limitation identified	Details of constraint identified	Project to address constraint	Project status
	exporting limits from Queensland to New South Wales		RIT-T.

D Review of Terranora (Directlink) interconnector

All constraints on Terranora are being adequately addressed by the relevant TNSP. Similarly, all network constraints in the main transmission corridors around Terranora in Queensland and New South Wales are being adequately addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a TNSP under its last resort planning powers.

This section provides the Commission's analysis of whether there are any constraints impacting the Terranora interconnector that are not being addressed by the relevant TNSPs. It includes the following:

- an overview of the Terranora interconnector
- a review of the binding constraint equations that most often set the limits on Terranora from AEMO's NEM constraint report for 2016
- a review of the emerging transmission network constraints affecting the Terranora interconnector from the 2016 NTNDP
- a review of Powerlink and TransGrid's 2017 transmission annual planning reports on projects to address constraints on Terranora and the main transmission corridors
- a summary of the projects identified to reduce transmission network constraints.

D.1 Overview of Terranora

The Terranora interconnector comprises of the two 110 kV lines from Terranora in New South Wales to Mudgeeraba in South East Queensland as set out in Figure D.1. The controllable element is a 180 MW direct current link between Terranora and Mullumbimby (both in New South Wales), known as Directlink. [62] It consists of three separate direct current lines with the capacity of 60 MW each.[63] Due to the local load connected around Terranora, the nominal capacity for Terranora differs from that of Directlink.[64] Directlink was commissioned in 2000, forming the first connection between New South Wales and Queensland.[65] The Terranora interconnector is owned by Energy Infrastructure Investments Pty Ltd and managed by APA group.[66]

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

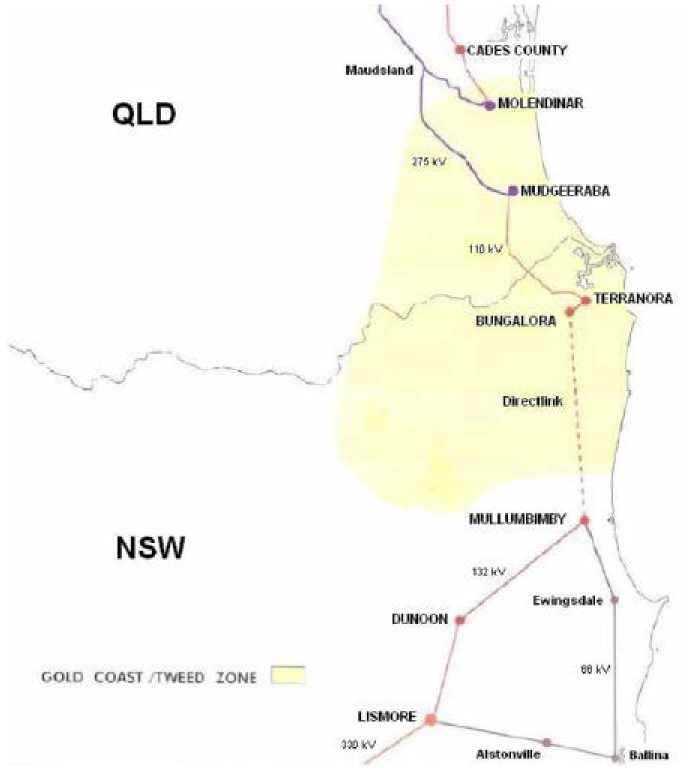
63 AEMO, *Interconnector capabilities*, September 2016, p7.

64 Ibid.

65 AEMO, *NEM Constraint report 2016*, June 2017, p24.

66 APA Group 2017, APA Group, viewed 27 September 2017, https://www.apa.com.au/our-services/other-energy-services/electricity-transmission-interconnectors

Figure D.1 Terranora interconnector



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

D.2 Findings from the NEM constraint report for 2016

According to the NEM constraint report by AEMO, the majority of flows on Terranora are towards New South Wales, so unlike other NEM interconnectors, both the import and export values are negative.[67] The Terranora interconnector normally appears with the QNI interconnector on the left hand side of the stability constraint equations, so both interconnectors may be constrained at the same time.

The Terranora interconnector is most commonly constrained by thermal limits in the northern New South Wales zone or the rate of change on Directlink.[68]

In 2016, most of the time that Terranora was restricted was due to either the stability constraint equations, the outage of all three Directlink cables or single Directlink cable outages.[69] The constraint equation for the outage of all three Directlink cables was binding for 865 hours in 2016 as compared to 1312 hours in 2015.[70]

The top three most binding system normal constraint equations, affecting flows across Terranora in either direction for 2016 are provided in Table D.1.

67 AEMO, *NEM constraint report 2016*, June 2017, p24

68 Ibid.

69 AEMO, *NEM constraint report 2016*, June 2017, p24.

70 AEMO, *NEM constraint report 2016*, June 2017, p13.

Table D.1 Binding constraint equations setting the Terranora limits in 2016 (system normal)

New South Wales to Queensland limits			
Equation ID	**Hours binding in 2016**	**Description**	**Market impact (with position in top ten system normal market impacts per region)[a]**
N^^Q_NIL_B1, 2, 3, 4, 5, 6 & N^Q_NIL_B (This constraint is also identified for QNI).	340.2	To avoid voltage collapse for the loss of the largest Queensland generator	$466,661 (number one in the top ten constraints with largest market impact in New South Wales)
NQTE_ROC	82.8	Rate of change limit (80MW/5 minute) for Terranora interconnector for New South Wales to Queensland flows	$5,677 (number seven in top ten constraints with a market impact in New South Wales)
N^Q_NIL_A (This constraint is the same as that identified for QNI).	72.3	To avoid voltage collapse on loss of Liddell to Muswellbrook (83) 330 kV line	$241,714 (number three in the top ten constraints with largest market impact in New South Wales)
Queensland to New South Wales limits			
QNTE_ROC	84.8	Rate of Change limit (80 MW / 5 Min) for Terranora Interconnector for Queensland to New South Wales flows	$3,606 (number seven in top ten constraints with a market impact in Queensland)
Q>NIL_MUTE_757 & Q>NIL_MUTE_758	22.8	To avoid overloading a Mudgeeraba to Terranora (757 or 758) 110 kV line on no contingencies	$112,850 (number three in top ten constraints with a market impact in New South Wales)
N_NIL_TE_B	1.7	Terranora Interconnector Queensland to New South Wales flow overall limits	$ 889 (constraint not in the top ten constraints in New South Wales by marginal value)

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

Source: AEMO, *NEM constraint report 2016*, June 2017 and *NEM constraint report 2016 supplementary data*, June 2017.

D.3 Network constraints affecting Terranora

D.3.1 Findings from the 2016 NTNDP

In its 2016 NTNDP, AEMO did not identify the need for increased power transfer capability between Queensland and New South Wales over the Terranora interconnector. AEMO did not identify any projected reliability or economic limitations that are likely to impact the Terranora interconnector in its NTNDP scenarios and forecast period of up to 2035-36.[71] Hence, the 2016 NTNDP does not list any proposed possible solutions to increasing Terranora's transfer capacity.

D.3.2 Findings from Powerlink's 2017 transmission annual planning report for Queensland

Consistent with the 2016 NTNDP, Powerlink's 2017 transmission annual planning report found that there were no network limitations forecast to eventuate in Queensland in the five year outlook period.[72] Hence, its annual planning review does not identify augmentation projects aimed at relieving constraints on the Terranora interconnector.

D.3.3 Findings from TransGrid's 2017 transmission annual planning report

TransGrid's transmission annual planning report identifies a number of potential projects in Northern New South Wales to address potential constraints on the transmission network in this area.[73] However, consistent with the 2016 NTNDP, TransGrid's transmission annual planning report does not identify any forecast constraints to be specifically impacting the Terranora interconnector or any augmentations projects to address such a constraint.

D.4 Summary of projects for identified network constraints

As there are no forecast reliability or projected economic limitations for Terranora according to the NTNDP, there are no constraints on this interconnector that are going unaddressed. Additionally, there are no network constraints in the main transmission corridors around Terranora in Queensland or New South Wales that are not being adequately addressed by the relevant TNSP.

71 AEMO, *National Transmission Network Development Plan*, December 2016, pp37-38.

72 Powerlink Queensland, *Powerlink Queensland Transmission Annual Planning Report*, June 2017, p74.

73 TransGrid, *New South Wales Transmission annual planning report 2017,* June 2017, p25.

E Review of Victoria–New South Wales interconnector

> All transmission network constraints on the Victoria-New South Wales interconnector are being addressed by the relevant TNSPs in their transmission annual planning reports. Similarly, all network constraints in the main transmission corridors around the interconnector in Victoria and New South Wales are being addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a TNSP under its last resort planning powers.

This section provides the Commission's analysis of whether there are any constraints impacting the Victoria–New South Wales interconnector that are not being addressed by the relevant TNSPs. This analysis includes:

- an overview of the Victoria-New South Wales interconnector
- a review of the binding constraint equations that most often set the limits on this interconnector from AEMO's NEM constraint report for 2016
- a review of the emerging transmission network constraints affecting the interconnector from the 2016 NTNDP
- a review of TransGrid and AEMO's 2017 transmission annual planning reports on projects to address constraints on the interconnector and the main transmission corridors[74]
- a summary of projects planned to reduce identified transmission network constraints.

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

New South Wales and Victoria are interconnected via the Victoria to New South Wales (VIC-NSW) interconnector. This interconnector comprises the 330 kV lines between Murray and Upper Tumut, Murray and Lower Tumut, and Jindera and Wodonga.[75] These lines link the South West New South Wales zone with the Northern Victoria zone containing a large amount of hydroelectric generation. As such, they are part of the 'northern corridor' running between Murray (New South Wales) and South Morang (Victoria). This part of the interconnector is set out in Figure E.1.

In addition, the interconnector also includes the 220 kV line between Buronga and Red Cliffs connecting Victoria's north west, part of the Country Victoria zone, to the South West New South Wales zone.[76] This part of the network delivers supply to load centres

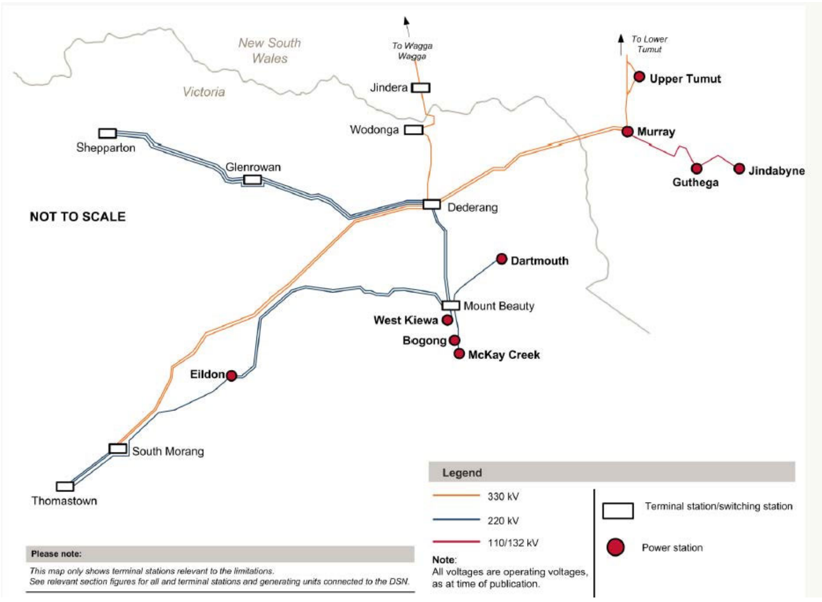
74 AEMO is responsible for the planning of the network in Victoria and is a TNSP for this purpose under the NER.

75 AEMO, *NEM constraint report 2016*, June 2017, p27.

76 AEMO, *NEM constraint report 2016*, June 2017, p27.

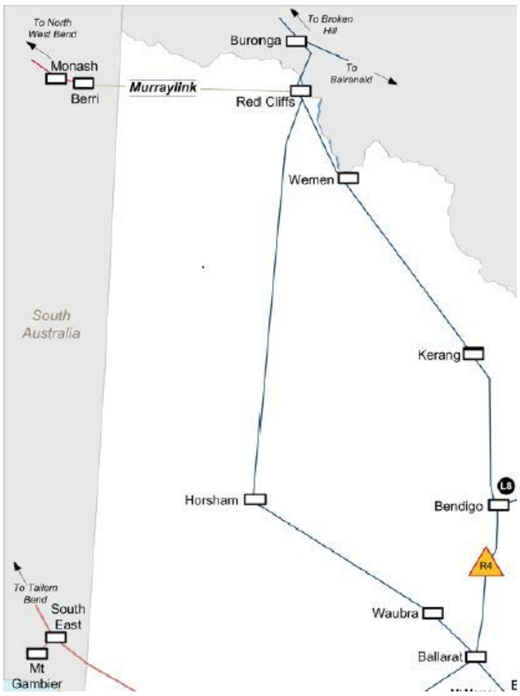
in the Country Victoria zone such as Bendigo and Ballarat and also transfers power to South Australia via the Murraylink interconnector. This part of the indicator is set out in Figure E.2.

Figure E.1 Victoria–New South Wales interconnector



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

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



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

E.2 Findings from the NEM constraint report for 2016

According to the NEM constraint report for 2016, the VIC-NSW interconnector appears in many of the Victorian constraint equations along with the other interconnections to Victoria. This can lead to situations where many or all of these interconnectors can be limited due to the same network limitation.

The VIC-NSW interconnector can bind in either direction due to high demand in New South Wales or Victoria. Transfers from Victoria to New South Wales are mainly limited due to thermal overload limits on the South Morang F2 transformer, the South Morang to Denderang 330 kV line, the Ballarat to Bendigo 220 kV line, or the Ballarat to Moorabool No. 1 220 kV line. The transient stability limit for a fault and trip of a Hazelwood to South Morang line may also set the Victoria to New South Wales limit.

Transfer from New South Wales to Victoria is mainly limited by voltage collapse for loss of the largest Victorian generator, or thermal overload limits on the Murray to Dederang 330 kV lines.[77]

In 2015 and 2016, the hours at each flow level and the binding hours on the Victoria–New South Wales interconnector were broadly similar. However in 2016, the high flow levels into New South Wales were constrained for more hours, when compared to 2015.[78] In 2016, the most commonly seen flows were at higher levels of around 700 MW to 1000 MW.

The top three most binding system normal constraints for 2016 impacting the flow across the Victoria-New South Wales interconnector in either direction are listed in Table E.1.

Table E.1 Binding constraint equations setting the Victoria–New South Wales interconnector limits in 2016 (system normal)

Victoria to New South Wales limits			
Equation ID	**Hours binding in 2016**	**Description**	**Market impact (with position in top ten system normal market impacts per region)[a]**
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P (This constraint was also identified on the Heywood, Murraylink and Basslink interconnectors)	957.1	To avoid overloading the South Morang 500/330 kV (F2) transformer for no contingencies, for radial/parallel modes and unit 1 at Yallourn Power station on the 500 or 220 kV	$144,342 (number six in top ten constraints with a market impact in Victoria)

77 AEMO, *NEM constraint report 2016*, June 2017, p27.

78 Ibid, p28.

		These constraint equations maintain flow on the South Morang F2 transformer below its continuous rating	
V::N_NILxxx (This constraint was also identified on the QNI,Heywood, Murraylink and Basslink interconnectors)	941.7	To avoid transient instability for fault and trip of a Hazelwood to South Morang 500 kV line	$238,531 (number four in top ten constraints with a market impact in Victoria)
V>>N-NIL_HA (This constraint was also identified on the Murraylink interconnector)	312.8	To avoid overload on Murray to Upper Tumut (65) 330 kV line on trip of Murray to lower Tumut (66) 330 kV line	$97,517 (number nine in top ten constraints with a market impact in Victoria)
New South Wales to Victoria limits			
N^^V_NIL_1 (This constraint was also identified on the Murraylink interconnector)	81.8	To avoid voltage collapse for loss of the largest Victorian generating unit	$42,416 (number six in top ten constraints with a market impact in New South Wales)
V>>V_NIL_1B (This constraint was also identified on the Murraylink interconnector)	1.8	To avoid overloading Dederang to Murray No.2 330 kV line for trip of the Dederang to Murray No.1 330 kV line This constraint equation binds for high transfers from New South Wales to Victoria with the Dederang bus splitting scheme active	$25,680 (not in the top ten constraints by market impact in Victoria)
V>>V_NIL_1A (This constraint was also identified on the Murraylink interconnector)	1.2	To avoid overload of Murray to Dederang No.1 330kV line (flow MSS to DDTS) for loss of the parallel No.2 line	$1,108 (not in the top ten constraints by market impact in Victoria)

[a] The market impact is calculated by adding up the marginal values from the marginal constraint cost re-run. To that end, the constraint is relaxed marginally (by 1 MW). This will result in a different dispatch pattern, with different associated costs, compared to the situation under the full constraint. This is done for

each dispatch interval during the number of hours a constraint was binding. These values are subsequently added up to provide a total marginal market impact.

Source: AEMO, *NEM constraint report 2016*, June 2017 and *NEM constraint report 2016 supplementary data*, June 2017.

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

E.3.1 Findings from the 2016 NTNDP

The 2016 NTNDP identified several potential economic limitations relevant to the VIC-NSW interconnector. They are expected under all modelling scenarios for the forecast period of up to 2035-36. One constraint is forecast to arise in New South Wales, spanning the region between the Canberra and Central New South Wales NTNDP zones, while four are expected to impact Victoria within the Northern Victoria zone. These constraints include:[79]

1. Transmission limitations on the Sydney to Canberra/Yass 330 kV corridor during times with high wind and PV generation in Canberra and high export from Victoria to New South Wales.

2. Transmission limitation on the South Morang 500/330 kV transformer during periods of high export from Victoria to New South Wales.

3. Transmission limitations on Dederang to South Morang 330 kV circuits when there is high transfer between Victoria and New South Wales including both import and export.

4. Transmission limitations on Eildon to Thomastown 220 kV line when there is high import from New South Wales into Victoria.

5. Transmission limitations on Dederang to Mt. Beauty 220 kV lines during periods of high export to New South Wales from Victoria.

E.3.2 Findings from TransGrid's New South Wales transmission annual planning report 2017

In its 2017 transmission annual planning report (TAPR), TransGrid has identified several possible network development opportunities to address the emerging constraints and support the connection of new renewable generation to its network. Among the proposed major developments is the reinforcement of the Snowy to Sydney network, which relates to the NTNDP forecast constraint on the Sydney to Canberra/Yass 330 kV corridor. The upgrade is proposed to have several benefits including: facilitating the connection of additional renewable generation to the network, an increase to the import capacity from Victoria into New South Wales by approximately 350 MW and facilitating the connection of increased generation capacity

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79 AEMO, *National Transmission Network Development Plan*, December 2016, pp37-42.

from an upgrade to the Snowy Hydro Scheme. [80] Project options for low and high capacity upgrades have been identified to achieve the reinforcement, and they include:

- Upgrading the 330 kV lines between Yass to Marulan, Canberra to Yass, Kangaroo Valley to Dapto, Sydney West to Bannaby, Gullen Range to Bannaby and Yass to Gullen Range to meet a 120°C design temperature. This option is expected to increase the transfer capacity by 160 MW. [81]

- Carrying out staged upgrades of the 330 kV lines between Bannaby to Sydney West (39) and Canberra to Upper Tumut (O1) to meet a 120°C design temperature, Yass to Marulan (4 and 5) to meet a 100°C design temperature, installing phase shifting transformers at Bannaby and Marulan substations, and construction of a new transmission line between Yass and Bannaby. This high capacity option is expected to increase the transfer capacity by approximately 970 MW. [82]

- Carrying out rebuilds of several of the 330 kV lines in the region to ratings between 1,300 MW and 2,100 MW. This option high capacity upgrade option is expected to increase the transfer capacity by approximately 1000 MW. [83]

These options are expected to cost between $60 million and $397 million. The decision to proceed with a project is subject to external outcomes such as the expansion of the Snowy Hydro Scheme.

TransGrid's TAPR also outlined a minor planned project to improve the New South Wales to Victoria transfer limit. The project involves installation of a 330 kV 100 MVAr shunt capacitor bank at Canberra, Stockdill or the Williamsdale substation. The project is aimed relieving the voltage stability issues that cause constraints on exports from New South Wales to Victoria during high demand periods. The project planned date is by June 2023 and it is expected to cost $5.5 million. [84]

Thus, TransGrid has outlined several planning options to address the transmission limitations on the Victoria-New South Wales interconnector which were forecast by AEMO in its 2016 NTNDP.

E.3.3 Findings from AEMO's Victorian transmission annual planning report for 2017

AEMO is responsible for planning and directing augmentation on the Victorian transmission network and it publishes the Victorian annual planning report (VAPR) as part of these responsibilities. [85] AEMO has identified a number of relevant emerging

80 TransGrid, *Transmission annual planning report,* June 2017, p22.

81 Ibid.

82 Ibid, p23.

83 Ibid.

84 TransGrid, *Transmission annual planning report,* June 2017, p36.

85 AEMO, *Victorian annual planning report,* June 2017, p1.

development opportunities and monitored transmission limitations in its 2017 VAPR, which align with Victorian constraints identified in its NTNDP.

The VAPR outlines two relevant emerging development opportunities which include improving Victoria to New South Wales export capability and Victoria to New South Wales import capability.[86] The development opportunities are relevant for all four of the Victorian NTNDP constraints that may impact VIC-NSW interconnector, namely constraint number two, three, four and five from section E.3.1. The augmentation projects identified by AEMO as part of the emerging development opportunities may address the relevant constraints but mostly in the short term, the longer term solution to these limitations are identified under the monitored constraints. The relevant emerging opportunities and their associated augmentations include the following:

- The export capability from Victoria to New South Wales is frequently limited by thermal capacity limitations on the South Morang F2 transformer and South Morang-Dederang 330 kV lines, and a transient stability limit. [87]To improve the Victoria to New South Wales export capability the following three augmentations are expected to be considered:[88]
    - installation of a new 500/300 kV transformer at South Morang
    - uprating of south Morang – Dederang 330 kV lines by conductor re-tensioning
    - increasing the transient export limit, through network or non-network solutions.
- The import capability from New South Wales to Victoria is restricted by thermal limitations on the Murray-Dederang 330 kV lines, the South Morang – Dederang 330 kV lines, and Dederang – Mount beauty – Eildon-Thomastown 220 kV transmission path as well as voltage stability limitation.[89] To improve the import capability the following network and non-network options are being considered:[90]
    - implementing an automatic load shedding scheme to allow for operating the Murray – Dederang 330 kV lines at a higher rating, in order to increase import limit by 200 MW.
    - procuring network support services to increase the voltage stability import limit to Victoria.

86 AEMO, *Victorian annual planning report,* June 2017, p23

87 Ibid, p25.

88 Ibid.

89 Ibid, p26.

90 Ibid.

- installing wind monitoring facilities on Dederang – Mount Beauty – Eildon – Thomastown 220 kV lines to increase transfer capabilities.
- implementing an automatic load shedding scheme to allow for operating the Dederang – Mount Beauty – Eildon – Thomastown 220 kV lines at a higher rating.

The projects identified above are not committed as yet. AEMO will commence a pre-feasibility study within a year on the need to improve Victoria to New South Wales export capability, which may trigger a RIT-T to identify the preferred option for increasing the Victoria to New South Wales transfer limit. AEMO will also commence a pre-feasibility study, including a market benefit assessment on the augmentation options for New South Wales to Victoria import capabilities and may pursue options which can be economically justified based on the assessment. [91]

As part of its responsibilities for Victoria, AEMO continually monitors the transmission network limitations that may result in supply interruptions or constrain the generation periodically. Some of the constraints identified in the 2016 NTNDP to be impacting the VIC-NSW interconnector are reported as monitored constraints in the 2017 VAPR. For the monitored constraints, AEMO also reports on augmentation to address these constraints. The augmentations proposed under monitored constraints are expected to serve as longer term solutions for some of the Victorian NTNDP constraints. The monitored constraints relate to limitations three, four and five from section E.3.1. The relevant monitored constraints and their outlined possible network solutions include: [92]

- The line loading limitations on the Dederang – South Morang 330 kV lines during increased imports from Victoria. AEMO identifies two possible solutions to this constraint including:[93]
  - uprating the two existing lines to 82 °C (conductor temperature) operation and series compensation at an estimated cost of $16.5 million
  - installing a new (third) 330 kV, 1,060 MVA single circuit line between Dederang and South Morang with 50% series compensation to match the existing lines, at an estimated cost of $239.6 million (excluding easement costs, and subject to obtaining the necessary easement).
- The lines loading limitations on the Eildon–Thomastown 220 kV line during increased New South Wales imports and exports. AEMO identifies the possible network solutions to include:[94]
  - installing a wind monitoring scheme at an estimated approximate cost of $500,000.

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91 AEMO, Victorian annual planning report, June 2017, p27.

92 AEMO, Victorian annual planning report, June 2017, p47.

93 Ibid.

94 ibid.

- uprating the Eildon–Thomastown 220 kV line, including terminations to 75 ºC operation, at an estimated cost of $43.7 million.

- Line loading limitations on the Dederang–Mount Beauty 220 kV line during increased New South Wales imports and exports. AEMO identifies the possible network solutions to include:[95]

  - installing a wind monitoring scheme at an estimated approximate cost of $500,000.

  - uprating the conductor temperature of both 220 kV circuits between Dederang and Mt. Beauty to 82 ºC at an estimated cost of $12.2 million.

In summary, the NTNDP constraints within Victoria that were deemed relevant for the VIC-NSW interconnector are being given sufficient consideration by AEMO. AEMO's VAPR outlined several augmentation options as parts of its emerging development opportunities which would address the constraints in the short run. AEMO also listed augmentation option for the constraints in its monitored constraints list which would provide longer term solutions to these constraints.

E.4 Summary of projects for identified network constraints

The forecast transmission constraints along the corridors leading up to the Victoria–New South Wales interconnectors are being addressed by the relevant TNSPS through their network augmentation plans. The TNSPs' plans to address the constraints were outlined in their transmission annual planning reports. Table E.2 provides a summary of constraints identified in relevant planning documents that may impact flows on the VIC-NSW interconnector and how these constraints are being addressed by TransGrid and AEMO.

95 ibid.

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

Report limitation identified	Details of constraint identified	Project to address the identified need	Project status
NTNDP for 2016 (economic constraint)	Transmission limitations between Yass/Canberra and Sydney during periods of high VIC-New South Wales export and Wind/PV generation in Canberra zone	A number different upgrade possibilities identified including upgrade options of 330 kV lines in the Yass/Canberra and Sydney corridor to meet increased design temperatures, a new transformer, new builds and rebuilds of existing lines are being considered (TransGrid)	A potential project could be initiated but the decision to proceed is contingent on external factors such as Snowy Scheme upgrade decision
2016 NTNDP (economic constraint)	Transmission limitations on South Morang 500/330 kV transformer, AEMO considers this is present when there is high export from Victoria to New South Wales	As part of emerging network opportunities, AEMO has identified a possible solution to be the Installation of a new 500/300 kV transformer at South Morang. (AEMO)	Projects are identified but not committed as yet, pre-feasibility assessment of the overall project is expected to be commenced within the next 12 months; a RIT-T may follow (AEMO)
2016 NTNDP (economic constraint)	Transmission limitations on Dederang-South Morang 330 kV circuits, AEMO considers that this constraint is present when there is high transfer between Victoria and New South Wales (export or import)	As part of emerging network opportunities AEMO has identified a possible solution be the uprating of south Morang – Dederang 330 kV lines by conductor re-tensioning (AEMO) The constraint is also a monitored limitation with an identified possible longer term solution	A project is identified but not committed as yet, pre-feasibility assessment of the overall project is expected to be commenced within the next 12 months; a RIT-T may follow that. (AEMO)

Report limitation identified	Details of constraint identified	Project to address the identified need	Project status
2016 NTNDP (economic constraint)	Transmission limitations on Eildon-Thomastown 220 kV line, AEMO considers that this constraint is present when there is high import into Victoria from New South Wales	As part of emerging network opportunities AEMO has identified two possible solutions including installing wind monitoring facilities or implementing an automatic load shedding scheme to allow for Dederang – Mount Beauty – Eildon – Thomastown 220 kV lines to be operated at higher ratings (AEMO) The constraint is also a monitored limitation with an identified possible longer term solution	Projects are identified but not committed as yet, pre-feasibility assessment of the overall project is expected to be commenced within the next 12 months
2016 NTNDP (economic constraint)	Transmission limitations on Dederang-Mt. Beauty 220 kV lines, AEMO considers that this constraint is present when there is high export from Victoria into New South Wales	As part of emerging network opportunities AEMO has identified a possible solution to include implementing an automatic load shedding scheme to allow for Dederang – Mount Beauty – Eildon – Thomastown 220 kV lines to be operated at higher ratings (AEMO) The constraint is also a monitored limitation with an identified possible longer term solution	Projects are identified but not committed as yet, pre-feasibility assessment of the overall project is expected to be commenced within the next 12 months

F Review of Heywood interconnector

All transmission network constraints forecast on the Heywood interconnector are being addressed by the relevant TNSPs in their transmission annual planning reports. Similarly, all network constraints in the main transmission corridors around the interconnector in Victoria and South Australia are being addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a TNSP under its last resort planning powers.

This section provides the Commission's analysis of whether there are any constraints impacting the Heywood interconnector that are not being addressed by the relevant TNSPs. The analysis includes:

- an overview of the Heywood interconnector
- a review of the binding constraint equations that most often set the limits on this interconnector from the AEMO’s NEM constraint report for 2016
- a review of the emerging transmission network constraints affecting this interconnector from the 2016 NTNDP and details of recent upgrades to the Heywood interconnector
- a review of ElectraNet and AEMO's 2017 transmission annual planning reports on projects to address constraints on the interconnector and the main transmission corridors
- a summary of the projects identified to reduce transmission network constraints.

F.1 Overview of the Heywood interconnector

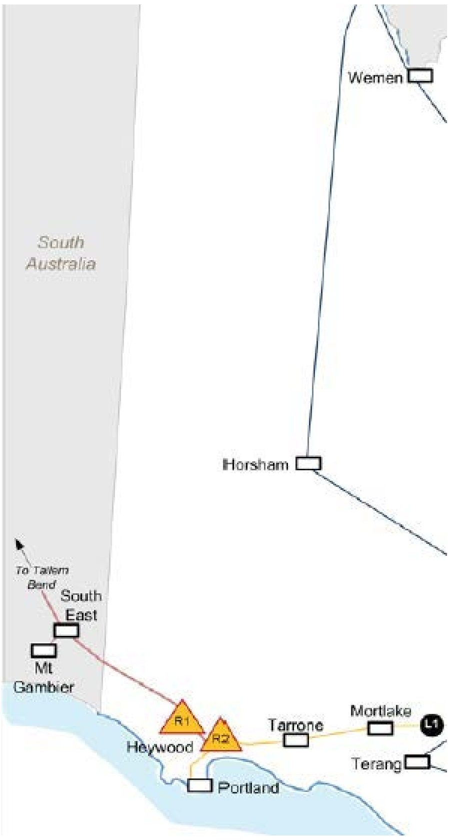
The Heywood interconnector, set out in Figure F.1, is an alternating current connection between Heywood substation in Victoria and the South East substation in South Australia.[96] It was originally commissioned in 1989 and following upgrades it now includes three 500/275 kV transformers at Heywood and connects into South Australia via a double circuit 275 kV line. [97]

Originally, most of the flows on the Heywood interconnector were from Victoria to South Australia. However, with the increasing number of wind farms in South Australia, the flow is now often from South Australia to Victoria.

96 AEMO, *Interconnector capabilities*, September 2015, p9.

97 Ibid.

Figure F.1 Heywood interconnector



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

Recent upgrades have been carried out on the interconnector, following the conclusion of a RIT-T by AEMO and ElectraNet, which outlined net positive market benefits to flow from the project. The upgrades were carried out to increase the interconnector's nominal transfer capacity by 190MW.[98] The augmentations carried out are further described in section F.3.1.

The projects to upgrade the interconnector have reached completion with the asset energised in July 2016.[99] Tests have been progressively carried out by AEMO to incrementally release the increased capacity into the market. At the time of this report's publication, the Victoria to South Australia transfer limit has been increased from 460 MW to 600 MW.[100]

98 ElectraNet 2016, ElectraNet, Adelaide, viewed 28 September 2017, https://www.electranet.com.au/projects/sa-vic-heywood-interconnector-upgrade/

99 Ibid.

100 AEMO, *Update Inter-Network Testing and Transfer Limit- Heywood Interconnector, Market Notice 54666*, 17 January2017.

F.2 Findings from the NEM constraint report for 2016

According to the NEM constraint report, the Heywood interconnector appears in many of the Victorian constraint equations along with other interconnectors to Victoria (VIC-NSW, Basslink, and Murraylink).This can lead to situations where many of these interconnectors can be limited due to the same network limitation.[101]

Before the upgrade, the flows from Victoria to South Australia were most often restricted by thermal overloads on the Snuggery to Keith 132 kV line, transient stability limit for loss of the largest South Australian generator and the Heywood 500/275 kV transformers. South Australia to Victoria transfers were mainly restricted by the thermal overload limits on the South East substation 275/132 kV transformers and the South Morang F2 transformer.[102]

Following the upgrade, flows from Victoria to South Australia were mostly limited by the transient stability limit for a fault and trip of a Hazelwood to South Morang 500 kV line, rate of change of frequency limit of 3 Hz/sec in South Australia, transient stability limit for loss of the largest South Australian generator and the 250 MW upper limit for outages that put South Australia at a risk of separating from the rest of the NEM.[103]

There was a difference in the most commonly observed flow levels across the Heywood interconnector between 2015 and 2016.[104] In 2015 there were high flows into South Australia with significant flow hours observed at the 450 MW level. In 2016, flows were still mostly from Victoria to South Australia and outages associated with the interconnector upgrade limited the flows at 250 MW for 232 hours.

The top three most binding system normal constraints for 2016 impacting flows on the Heywood interconnector in either direction are listed in Table F.1.

Table F.1 Binding constraint equations setting the Heywood interconnector limits in 2016 (system normal)

Victoria to South Australia limits			
Equation ID	**Hours binding in 2016**	**Description**	**Market impact (with position in top ten system normal market impacts per region)[a]**
V::N_NILxxx (This constraint was also identified on the QNI,VIC-NSW,	574.9	To prevent transient instability for fault and trip of a Hazelwood-South Morang 500 kV line	$238,531 (number four in the top ten constraints with largest market impact in Victoria)

101 AEMO, *NEM constraint report 2016*, June 2017, p29.

102 Ibid.

103 Ibid.

104 ibid, p26.

Murraylink and Basslink interconnectors)		AEMO notes that there are twelve constraint equations that make up the transient stability export limit from Victoria and all the binding results have been combined.	
V_S_NIL_ROCOF	391.9	To limit Victoria to South Australia Heywood flow to prevent rate of change of frequency exceeding 3 Hz/sec in South Australia immediately following loss of Heywood interconnector	$303,197 (number three in the top ten constraints with largest market impact in Victoria)
V::S_NIL_MAXG_xx x	366.3	To avoid transient instability for trip of the largest generation unit in South Australia	$116,390 (number seven in the top ten constraints with largest market impact in South Australia)
South Australia to Victoria limits			
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P (This constraint was also identified on the Victoria–New South Wales, Murraylink and Basslink interconnectors).	945.3	To avoid overloading the South Morang 500/330 kV (F2) transformer for no contingencies, for radial/parallel modes and Yallourn W1 on the 500 or 220 kV These constraint equations maintain flow on the South Morang F2 transformer below its continuous rating	$144,342 (number six in the top ten constraints with largest market impact in Victoria)
S>>V_NIL_SETX_S ETX1	15.2	To avoid overloading a South East 132/275 kV transformer on trip of the remaining South East 132/275 kV transformer	$49,147 (not in the top ten constraints with largest market impact in South Australia)
S>>V_NIL_SETX_S ETX	12.2	To avoid overloading a South East 275/132 kV transformer on trip of	$100,856 (number eight in the top ten constraints with largest market

		the remaining South East 275/132 kV transformer	impact in South Australia)

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

Source: AEMO, *NEM constraint report 2016*, June 2017 and *NEM constraint report 2016 supplementary data*, June 2017.

F.3 Network constraints on the Heywood interconnector

F.3.1 Augmentation of the Heywood interconnector

As mentioned earlier in section F.1, an upgrade of the Heywood interconnector was undertaken following the conclusion of a RIT-T by AEMO and ElectraNet. It was carried out with the aim of increasing the interconnector transfer capacity by approximately 40%, in order to realise net market benefits over the project's lifetime of approximately $190 million in present value terms. Commencing in July 2013, the scope of upgrades for the Heywood interconnector included the following:[105]

- a third 500/275 kV transformer at the Heywood 500 kV transmission terminal station
- series compensation of the two South East to Tailem Bend 275 kV lines
- reconfiguration of substation assets and the existing 132 kV transmission system to allow increased utilisation of transmission line thermal ratings along the 275 kV interconnector
- a South East 275/132 kV transformer control scheme.

Initial service of the full upgrade was completed in August 2016.[106] Since then, AEMO has progressively carried out tests to incrementally release the increased capacity into the market.

The increased maximum design limit of 650MW flow in both directions has not yet been fully released into the market. AEMO's analysis of the South Australia black system event, which occurred in September 2016, has identified a potential transient stability issue which is seen during high Victoria to South Australia transfers and high levels of wind generation in South Australia. AEMO and ElectraNet are currently reviewing the transient stability limits and transfer limits applied to the interconnector.[107]At the time of this report's publication, Heywood interconnector transfers limits

105 ElectraNET, *South Australian transmission annual planning report*, June 2016 pp56-57.

106 AEMO, *Victorian annual planning report,* June 2017, p21.

107 Ibid, p16.

from Victoria to South Australia were set at equal to or below 600 MW, while transfer limits from South Australia to Victoria were set at equal to or below 500 MW. [108]

F.3.2 Findings from the 2016 NTNDP

The 2016 NTNDP identified one forecast economic limitation that may impact the flows across the Heywood interconnector in its forecast period of up to 2035-36. [109]

AEMO has forecast transmission limitations along the Tailem Bend to Tungkillo south east transmission corridor of South Australia. The constraint is expected to transpire during high levels of wind and or solar generation in the northern South Australia and Adelaide zones. It is forecast to occur under the neutral and low grid demand scenarios as outlined in Table B.1.

AEMO does not identify any inter-regional constraints within the Victorian transmission corridor leading up to the Heywood interconnector in the 2016 NTNDP.[110]

F.3.3 Findings from ElectraNet's 2017 transmission annual planning report

As part of its network planning process for 2017, ElectraNet developed a central planning scenario and applied a number of sensitivities to investigate different development pathways for the South Australian network. Under the considered scenario and sensitivities, ElectraNet identified several projects that are relevant for inter-regional transfers via the Heywood interconnector as reported in its transmission annual planning report (TAPR).

In its 2017 TAPR, ElectraNet identified two projects to address the forecast transmission limitation on the Tailem Bend to Tungkillo south east transmission corridor of South Australia.[111] The relevant projects are as following:

- A project to populate an additional diameter at Tungkillo to connect the Tailem Bend to Cherry Gardens 275 kV line. The project is classified as a market benefit driven project. Tying in the Tailem Bend to Cherry Garden 275 kV line is currently proposed in ElectraNet’s Network Capability Incentive Parameter Action Plan (NCIPAP) for the 2018-19 to 2022-23 period. The project status is currently as proposed with the expected timing of June 2020. The project has an estimated cost of $3-6 million and is expected to increase the Heywood interconnector’s transfer capacity by 10MW.[112]

108 AEMO, Update Inter-Network Testing and Transfer Limit- Heywood Interconnector, Market Notice 54666, 17 January2017

109 AEMO, *National transmission network development plan,* December 2016, p39.

110 AEMO, *National transmission network development plan,* December 2016, p37-42.

111 ElectraNet, *South Australian transmission annual planning report*, June 2017, p30.

112 Ibid, p73.

- Construction of a new high capacity interconnector between South Australia and the Eastern states. ElectraNet has commenced a RIT-T process to explore the feasibility of further interconnection between South Australia and the eastern states with a project specification consultation report (PSCR) published in November 2016. The project is aimed at addressing the emerging challenges for the secure and stable operation of the South Australia power system. So far, four credible network options, each involving an interconnector to the eastern states as well as non-network solutions have been identified. These will be analysed further in the next stages of the RIT-T process. The options being considered are the following: [113]

  - central South Australia to Victoria interconnector, nominally Tungkillo to Horsham, and beyond

  - mid North South Australia to New South Wales interconnector, nominally Robertstown to Buronga

  - northern South Australia to New South Wales interconnector, nominally Davenport to Mt Piper

  - northern South Australia to Queensland interconnector, nominally Davenport to Bulli Creek

  - a variety of non-network options such as large-scale batteries, demand management and generation.

ElectraNet's TAPR also flagged several other planned projects to be impacting interregional flows. Some of these were deemed relevant for the Heywood interconnector, even though the TAPR did not directly identify them to be addressing the NTNDP limitation on the Tailem Bend–Tungkillo corridor. These flagged projects are identified to be in different categories including committed projects and market benefit opportunities.

A committed project currently underway with a potential to impact flows across the Heywood interconnector is the Tailem Bend substation upgrade. The scope of works includes extension of the substation to accommodate an additional 275 kV diameter with two circuit breakers, associated plant and secondary systems, and rearranging of 275 kV line exits. With construction in progress, the project with an estimated cost of $9-10million is expected to be delivered by November 2017. [114]

ElectraNet also identified two projects categorised as market benefit opportunities that may be expected have an impact on the flows across the Heywood interconnector. These projects are along its transmission corridor leading to the Heywood interconnector. The projects are the following:

- Applying dynamic ratings to transmission lines between South East and Tungkillo. Increasing the dynamic rating of these lines will reduce congestion of

113 Ibid, pp 61-62.

the Heywood interconnector, enabling increased power flow from Victoria to South Australia by approximately 31 MW. The project status is as proposed with the estimated cost of below $5 million. [115]

- Installation of an additional 100 MVAr 275kV capacitor bank at South East substation. It is envisaged that this project will impact interregional transfer, by enabling voltage stability to be maintained at increased transfer levels across the Heywood interconnector. The project status is as proposed with the estimated cost of below $5 million. [116]

In summary, ElectraNet identified two projects to address the forecast transmission limitations along the Tailem Bend to Tungkillo south east transmission corridor of South Australia. Other planned projects with the potential to impact flows across the Heywood interconnector were also outlined in ElectraNet's TAPR.

F.3.4 Findings from the AEMO's 2017 Victorian transmission annual planning report

AEMO publishes the Victorian annual planning report (VAPR) as part of its planning responsibilities for Victoria. In alignment with its NTNDP, AEMO does not forecast any major limitations for Heywood or for the flow paths leading up to the interconnector in its 2017 VAPR. Accordingly, AEMO does not identify any projects specifically for the Heywood interconnector or transmission corridors in Victoria around the Heywood interconnector in its 2017 VAPR.

F.4 Summary of projects for identified network constraints

There was one forecast constraint that was identified to be relevant for the Heywood Interconnector, falling in the South Australian region. ElectraNet's TAPR identified two market benefit projects to address the forecast constraint. The TAPR also identified several other projects with the potential to assist flow across the Heywood interconnector. Hence, there are no transmission network constraints on the Heywood interconnector, or in the transmission corridors around this interconnector in Victoria and South Australia that are not being addressed by the relevant TNSPs in their transmission annual planning reports. Table F.2 provides a summary of identified constraints relating to the Heywood interconnector and how these constraints are being addressed by the relevant planning body in their transmission annual planning reports.

114 ElectraNet, *South Australian transmission annual planning report*, June 2017, p55.

115 Ibid, p70.

116 Ibid, p71.

Table F.2 Identified constraints relating to the Heywood interconnector and how these are being addressed

Report limitation identified	Details of constraint identified	Project addressing constraint	Project status
2016 NTNDP (economic constraint)	Transmission limitations on the Tailem Bend-Tungkillo transmission corridor during high levels of wind and or solar generation in the northern South Australia and Adelaide zones	Connecting the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo by populating one additional diameter at Tungkillo (ElectraNet)	Project has the status as proposed and it is included in ElectraNet's proposed NCIPAP for the 2018-19 to 2022-23 period
		A new high capacity interconnector between South Australia and the eastern states as proposed in the options of the South Australia Energy Transformation RIT-T (ElectraNet)	ElectraNet commenced a RIT-T in November 2016 by publishing a PSCR, timing and scope of the project are subject to further analysis

G Review of Murraylink interconnector

> All transmission network constraints on the Murraylink interconnector are being addressed by the relevant TNSPs in their annual planning reports. Similarly, all network constraints in the main transmission corridors around the interconnector in Victoria and South Australia are being addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a TNSP under its last resort planning powers.

This section provides the Commission's analysis of whether there are any constraints impacting the Murraylink interconnector that are not being addressed by the relevant TNSPs. The analysis includes:

- an overview of the Murraylink interconnector
- a review of the binding constraint equations that most often set the limits on this interconnector from the AEMO's NEM constraint report for 2016
- a review of the emerging transmission network constraints affecting this interconnector from the 2016 NTNDP
- a review of ElectraNet and AEMO's 2017 transmission annual planning reports on projects to address constraints on the interconnector and the main transmission corridors
- a summary of the projects identified to reduce transmission network constraints.

G.1 Overview of Murraylink interconnector

Murraylink is a high voltage direct current (HVDC) link that connects the Red Cliff 220 kV substation in Victoria to the Monash 132 kV substation near Berri in South Australia, as set out in Figure G.1.[117] The link spans approximately 180 km and is designed to transfer 220 MW at the receiving end. It was commissioned in 2002 and is owned by Energy Infrastructure Investments Pty Ltd and operated by the APA Group.[118] Murraylink features runback schemes that allow control of the flow across the interconnector in response to operation of an associated protection system.[119]

The interconnector connects the Country Victoria and Northern South Australia NTNDP zones. The wider country Victoria zone includes load centres such as Geelong and Ballarat, and it links to the Melbourne and Northern Victoria zones. The Northern

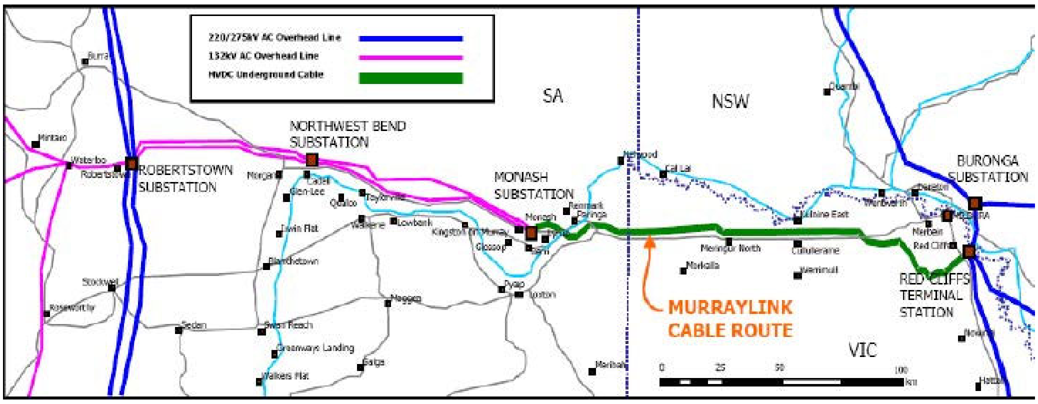
117 ElectraNet, *Transmission annual planning report*, June 2017, p 104.

118 Australian Energy Regulator 2014, Australian Energy Regulator, Melbourne, viewed 29 September 2017, https://www.aer.gov.au/networks-pipelines/service-providers-assets/murraylink-electricity-transmission-interconnector

119 Energy infrastructure investments, *Murraylink contingent project proposal*, May 2012, p2.

South Australia zone includes the Mid-North, Upper North, Eyre Peninsular and Riverland areas. The zone is connected to the Adelaide zone via three 275 kV circuits and one 132 kV circuit.

Figure G.1 Murraylink interconnector



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

G.2 Findings from the NEM constraint report for 2016

According to the NEM constraint report for 2016, Murraylink appears in many of the Victorian constraint equations along with other interconnectors to Victoria (VIC-NSW, Heywood and Basslink). This can lead to situations where many or all of these interconnectors can be limited due to the same network limitation. Many of the thermal issues close to Murraylink are handled by the South Australian or Victorian Murraylink runback schemes.[120]

Transfers from Victoria to South Australia on the Murraylink interconnector are mainly limited by thermal overloads on the South Morang F2 transformer, South Morang to Denderang 330 kV line, Ballarat to Bendigo 220 kV line, or Ballarat North to Buangor 66 kV line.[121] Alternatively these flows may be limited by the voltage collapse limit for loss of the Darlington Point to Buronga (X5) 220 kV line for an outage of the New South Wales Murraylink runback scheme.[122]

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

In 2015 and 2016, the number of hours at each flow level on Murraylink was very similar. The main difference in 2016 was an increase at higher flows in both directions,

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

121 AEMO, *NEM constraint report 2016*, June 2017, p30.

122 The NSW Murraylink scheme has not yet been commissioned so this constraint equation is currently part of the Victorian system normal constrain set

and an increase in constraint binding hours at 0 MW where they totalled approximately 800 hours.[123]

The top three most binding system normal constraints on the Murraylink interconnector for 2016 in either direction are outlined in Table G.1.

Table G.1 Binding constraint equations setting the Murraylink limits in 2016

Victoria to South Australia limits			
Equation ID	**Hours binding in 2016**	**Description**	**Market impact (with position in top ten system normal market impacts per region)[a]**
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P (This constraint was also identified on the VIC-NSW, Heywood, and Basslink interconnectors).	879.1	To avoid overloading the South Morang 500/330 kV (F2) transformer for no contingencies, for radial/parallel modes and Yallourn W1 on the 500 or 220 kV These constraint equations maintain flow on the South Morang F2 transformer below its continuous rating	$144,342 (number six in top ten constraints with largest market impact in Victoria)
V::N_NILxxx (This constraint was also identified on the QNI, VIC-NSW, Heywood, and Basslink interconnectors).	807.8	To prevent transient instability for fault and trip of a Hazelwood to South Morang 500 kV line AEMO notes that there are twelve constraint equations that make up the transient stability export limit from Victoria and all the binding results have been combined	$238,531 (number four in top ten constraints with largest market impact in Victoria)
VSML_220	467.4	Upper transfer limit of 220 MW on Victoria to South Australia on Murraylink	$890,029 (number one in top ten constraints with largest market impact in Victoria)

123 AEMO, NEM constraint report 2016, June 2017, pp30-31.

South Australia to Victoria limits			
S>V_NIL_NIL_RBNW	585.8	To avoid overloading the North West Bend to Robertstown 132 kV line on no line trips AEMO notes that this constraint normally sets the upper limit on Murraylink	$127,120 (number four in top ten constraints with largest market impact in South Australia)
S>NIL_NIL_NWMH2	36	To avoid overloading North West Bend-Monash #2 132 kV	$142,013 (number three in top ten constraints with largest market impact in South Australia)
SVML_ROC_80	33.9	The rate of change (South Australia to Victoria) constraint (80 MW/5 Min) for Murraylink	$12,554 (not in top ten constraints with largest market impact in South Australia or South Australia)

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

Source: AEMO, *NEM constraint report 2016*, June 2017 and *NEM constraint report 2016 supplementary data*, June 2017.

G.3 Network constraints on the Murraylink interconnector

G.3.1 Findings from the 2016 NTNDP

The 2016 NTNDP identifies one potential economic constraint that may impact on flows across the Murraylink interconnector in the forecast period of up to 2035-36.[124]

Transmission limitations are forecast on the 132 kV network in the Riverland region of South Australia, which spans between Berri and Robertstown substations. AEMO considers that this constraint may emerge during high levels of wind and or solar generation in the Northern South Australia zone and high Murraylink export to Victoria. It is forecast to occur under the neutral and low grid demand scenarios as outlined in Table B.1.[125]

AEMO does not identify any inter-regional constraints in the Victorian transmission network that are likely to impact the Murray interconnector flows.

124 AEMO, *National Transmission Network Development Plan*, December 2016, p38.

125 Ibid, p21.

G.3.2 Findings from ElectraNet's 2017 South Australian transmission annual planning report

As part of its network planning process for 2017, ElectraNet developed a central planning scenario and applied a number of sensitivities to investigate different development pathways for the South Australian network. Under the considered scenario and sensitivities, ElectraNet identified several projects that are relevant for inter-regional transfers via the Murraylink interconnector as reported in its transmission annual planning report (TAPR).

In its 2017 TAPR, ElectraNet identified two projects to address the NTNDP forecast Transmission limitations on the 132 kV network in the Riverland region of South Australia.[126] The relevant projects that address the constraint include:

- Uprating of the Riverland lines, more specifically, uprating of the Robertstown to North West Bend No. 2 132 kV line and the North West Bend to Monash No. 2 132 kV line from 80°C to design clearances to 100°C design clearances. The project increases the export capability from South Australia to Victoria through Murraylink by approximately 24 MW, under higher Riverland demand. The project was included in ElectraNet's network capability incentive parameter action plan (NCIPAP) for the 2014-15 to 2017-18 period. Its estimated cost is below $5 million and is classified as a committed project in ElectraNet's TAPR.[127]
- Construction of a new high capacity interconnector between South Australia and the Eastern states. ElectraNet has commenced a RIT-T process to explore the feasibility of further interconnection to the eastern states with a project specification consultation report (PSCR) published in November 2016. The project is aimed at addressing the emerging challenges for the secure and stable operation of the South Australia power system. So far, four credible network options and non-network solutions have been identified. These will be analysed further in the next stages of the RIT-T process.[128] The credible network options are further described in section F.3.4

ElectraNet's TAPR also flagged several other planned projects to be impacting interregional flows. Some of these were deemed relevant for the Murraylink interconnector, even though the TAPR did not explicitly identify them to be addressing the NTNDP transmission limitation on the 132 kV network in the Riverland region. These projects are along the transmission corridor leading to the Murraylink interconnector and are classified as market benefit opportunities. The relevant projects include:

- Uprating the Waterloo East to Robertstown 132 kV line from 80°C design clearances to 100°C design clearances. The project will increase transfer capacity

126 ElectraNet, *Transmission annual planning report,* June 2017, p29.

127 Ibid, p69.

128 Ibid, p24.

of the line and thereby reduce congestion on the Murraylink interconnector. It will facilitate increased power export to Victoria from South Australia under high Riverland demand by approximately 37 MW. The project is included in ElectraNet's network capability incentive parameter action plan (NCIPAP) for the 2014-15 to 2017-18 period. The project is currently planned with an estimated cost of below $5 million and an expected time of June 2018. [129]

- Improving the circuit breaker arrangement of Robertstown substation. The project entails installing a single 275 kV circuit breaker and associated equipment between the 275 kV buses at the substation. It is envisaged to alleviate constraints on the Murraylink interconnector during planned outages at Robertstown substation. The project is categorised under security and compliance with the status as proposed. Its estimated cost is $5-8 million with the expected timing of June 2020.[130]

- Applying short term overload ratings to the Robertstown 275/132 kV transformers. The project entails installation of transformer management relays and bushing monitoring equipment to enable the application of short term ratings. The project is included in ElectraNet's proposed network capability incentive parameter action plan (NCIPAP) for the 2018-19 to 2022-23 period. The project is currently proposed with the estimated cost of below $5 million and expected timing of June 2022. [131]

In summary, ElectraNet directly identified two projects to address the forecast constraint on the 132 kV network in the Riverland region. Other planned projects that were deemed to impact flows across the Murraylink interconnector were also outlined.

G.3.3 Findings from AEMO's 2017 Victorian transmission annual planning report

AEMO publishes the Victorian annual planning report (VAPR) as part of its planning responsibilities for Victoria. In alignment with its NTNDP, it did not identify any limitations for the Murraylink interconnector or parts of the Victorian network surrounding the Murraylink interconnector in its 2017 VAPR. Accordingly, AEMO does not identify any projects to specifically relieve constraints on the Murraylink interconnector.

However it is worth noting that AEMO has initiated the western Victoria renewable integration RIT-T. AEMO has taken a proactive approach to investigating the need for increased network capacity for areas rich in wind and solar resources. Thus, it has initiated the RIT-T with a primary focus of facilitating the integration of renewable generation capacity into the Victorian transmission network.[132] The options identified

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129 ElectraNet, *Transmission annual planning report,* June 2017, p70.

130 Ibid, p72.

131 Ibid, p73.

132 AEMO, *Victorian annual planning report,* June 2017, p33.

in the RIT-T thus far may have ramifications for the flows across the Murraylink interconnector.

AEMO has identified a high level of interest in renewable generation connections in the western Victoria region, which has been further accentuated by the proposed Victorian Renewable Energy target (VRET). [133] Thus far, AEMO has received applications and enquiries for over 5,000 MW of new generation within the region.[134] Without network augmentations or non-network solutions, new generators connecting to this region are expected to be heavily constrained by emerging thermal and system strength limitations, with up to half of their energy output curtailed.[135]

During times of peak renewable generation, excess power is also expected to flow to South Australia via the Murraylink interconnector, which may increase congestion in South Australia. The new generators in western Victoria may also require the redesign of Murraylink runback schemes. [136]

Thus far the RIT-T process has identified five options that could address the identified need, ranging between minor network augmentations, major network reinforcements and non-network options.[137] Some of the options are contingent upon other proposed augmentation projects, such as the South Australia – Victoria interconnector, being considered by ElectraNet as part of its South Australian Energy Transformation RIT-T.[138] The next stage of the western Victoria renewable integration RIT-T process will involve full options analysis and publication of the Project Assessment Draft report, which is expected around July 2018. [139]

G.4 Summary of projects for identified network constraints

There was one forecast constraint from the NTNDP that was identified to be relevant for the Murraylink Interconnector, falling in South Australia's Riverland region. ElectraNet has identified two projects that may address the forecast constraint. It has also identified several other projects with the potential to assist the flow across the Murraylink interconnector.

Hence, there are no transmission network constraints on the Murraylink interconnector or in the transmission corridors around this interconnector in Victoria or South Australia that are not being addressed by the relevant TNSPs in their transmission

133 AEMO, *Western Victoria Renewable Energy Integration*, Project specification consultation report, April 2017, p1.

134 Ibid, 34.

135 AEMO, *Western Victoria Renewable Energy Integration*, Project specification consultation report, April 2017, p35.

136 Ibid, p31.

137 Ibid, p35.

138 Ibid.

139 AEMO, *Victorian annual planning report*, June 2017, p36.

annual planning reports. Table G.2 provides a summary of the projects that address the constraint forecast by the NTNDP2016.

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

Report limitation identified	Constraint details	Project to address constraint	Project status
NTNDP for 2016 (economic constraint)	Transmission limitations are forecast on the 132 kV network in the Riverland region of South Australia during high levels of wind and or solar generation in the Northern South Australia zone and high Murraylink export to Victoria	Uprating of the Robertstown to North West Bend No. 2 132 kV line and the North West Bend to Monash No. 2 132 kV line from 80°C to design clearances to 100°C design clearances (ElectraNet)	Project is committed and is included in ElectraNet's network capability incentive parameter action plan (NCIPAP) for the 2014-15 to 2017-18 period.
		A new high capacity interconnector between South Australia and Eastern States as proposed in the options of the South Australia Energy Transformation RIT-T (ElectraNet)	Several options considered in the South Australian Energy Transformation RIT-T, The specification consultation report (PSCR) published in November 2016

H Review of Basslink interconnector

All transmission network constraints on the Basslink interconnector are being addressed by the relevant TNSPs in their annual planning reports. In addition, all network constraints in the main transmission corridors around the interconnector in Victoria and Tasmania are being addressed. As such, there is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a TNSP under its last resort planning powers.

This section provides the Commission's analysis of whether there are any constraints impacting the Basslink interconnector that are not being addressed by the relevant TNSPs. It includes the following:

- an overview of the Basslink interconnector
- a review of the binding constraint equations that most often set the limits on this interconnector from AEMO's NEM constraint report for 2016
- a review of the emerging transmission network constraints affecting this interconnector from the 2016 NTNDP
- a review of TasNetworks and AEMO's 2017 transmission annual planning reports on projects to address constraints on the interconnector and the main transmission corridors
- a summary of the projects identified to reduce transmission network constraints.

H.1 Overview of Basslink interconnector

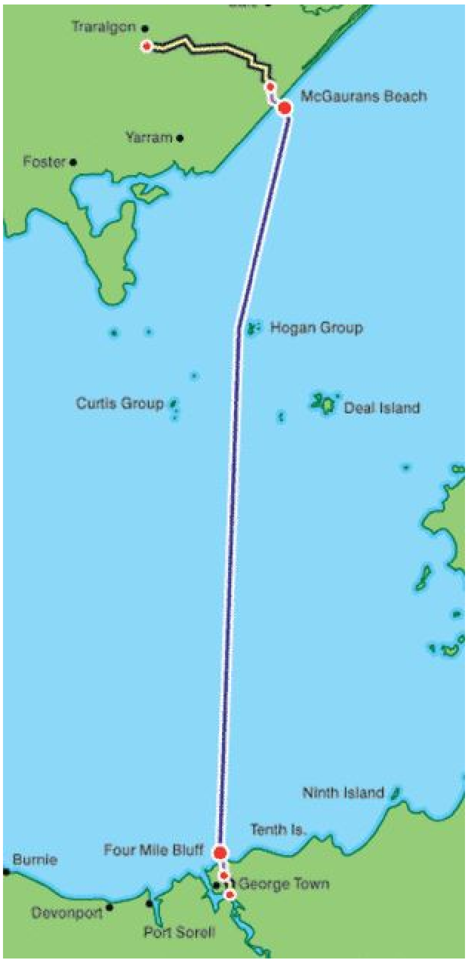
Victoria and Tasmania are connected via the Basslink interconnector. Basslink is a direct current interconnection between George Town in Tasmania and Loy Yang in the Latrobe Valley area in Victoria as set out in Figure H.1. It is an unregulated market link that was commissioned in early 2006 after Tasmania joined the NEM.[140] Basslink is owned by Keppel Infrastructure Trust.[141] Unlike the other direct current lines in the NEM, Basslink also has a frequency controller which enables it to transfer frequency control ancillary services between Tasmania and Victoria.[142]

140 AEMO, *NEM constraint report 2016*, June 2017, p26.

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

142 AEMO, *NEM constraint report 2016*, June 2017, p26.

Figure H.1 Basslink interconnector



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

The Latrobe Valley area has a significant amount of coal-fired generation. It is a major exporter of energy, principally to Melbourne and Moorabool through to Heywood (via its 500 kV and 220 kV transmission networks – the 'Eastern corridor'), and also to regional Victoria and Tasmania. The Tasmanian region has a significant amount of hydroelectric generation that is geographically dispersed across the region.

As Basslink is an unregulated market interconnector and not a TNSP, it is not required to apply the RIT-T to address an identified investment need on the interconnector. Therefore, if the Commission identified a deficiency in the planning arrangements of the interconnector it would not be able to direct Basslink to carry out a RIT-T under the last resort planning power. However, if the identified constraints could be alleviated in the transmission corridors connecting to Basslink, or through the construction of another interconnector, the Commission could direct the TNSP in Victoria, Tasmania or both to undertake a RIT-T.

Recently, a long term outage occurred on the interconnector following a fault on the subsea section of Basslink interconnector’s HVDC cable. The outage lasted for nearly six months between 20 December 2015 and 13 June 2016. [143] The fault investigation completed in December 2016 identified the reason for outage to be 'cause unknown'. [144]

H.2 Findings from the NEM constraint report for 2016

AEMO's NEM constraint report outlined that majority of constraints affecting Basslink transfers were due to frequency control ancillary service (FCAS) constraint equations for both mainland and Tasmanian contingency events.[145]

Transfers from Tasmania to Victoria were mainly limited by the energy constraint equations for the South Morang F2 transformer overload and or transient over-voltage at George Town. Flows from Victoria to Tasmania were mainly constrained due to the transient stability limit for a fault and trip of Hazelwood–South Morang line.

In 2016, Basslink was out of service for more than a hundred days due to physical damage to the undersea power cable, and its flow was limited to zero for one third of the year.[146] Hence, the dominant flow level seen across the interconnector in 2016 was zero MW, and the relevant outage constraint equation limiting power flow to zero MW was dominant amongst the constraints.

The top three most binding system normal constraints impacting the Basslink flow in either direction for 2016 are outlined in Table H.1.

Table H.1 Binding constraint equations setting the Basslink limits in 2016 (system normal)

Tasmania to Victoria limits			
Equation ID	**Hours binding in 2016**	**Description**	**Market impact (with position in top ten system normal market impacts per region)[a]**
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P (This constraint was also identified on the Victoria–New South Wales, Heywood and Murraylink interconnectors).	814	To avoid overloading the South Morang 500/330 kV (F2) transformer for no contingencies, for radial/parallel modes and Yallourn W1 on the 500 or 220 kV AEMO notes that these	$144,342 (number six in top ten constraints with a market impact in Victoria)

143 Hydro Tasmania 2017, Hydro Tasmania, Hobart, viewed 3 October 2017, https://www.hydro.com.au/energy/basslink

144 Basslink, *Basslink fault cause investigation completed – Media statement*, 5 December 2016

145 AEMO, *NEM constraint report 2016*, June 2017, p26.

146 AEMO, *NEM constraint report 2016*, June 2017, p26 and *NEM constraint report 2016 supplementary data*, June 2017.

		constraint equations maintain flow on the South Morang F2 transformer below its continuous rating	
T^V_NIL_9	21.1	To limit Basslink to 350 MW under conditions of sustained low fault levels at George Town 220 kV, to avoid uncoordinated switching of EHV capacitor banks around George Town resulting in insufficient reactive margin at George Town 220 kV	$10,067 (number eight in top ten constraints with a market impact in Tasmania)
T^V_NIL_BL_6	4.5	To prevent transient over-voltage (TOV) at George Town 220 kV bus for loss of Basslink	$2,459 (does not appear in top ten constraints with a market impact in Tasmania or Victoria)
Victoria to Tasmania limits			
V::N_NILxxx (This constraint was also identified on the QNI, VIC-NSW, Heywood and Murraylink interconnectors)	618.5	To avoid transient instability for fault and trip of a Hazelwood to South Morang 500 kV line. There are twelve constraint equations that make up the transient stability export limit from Victoria and all the binding results have been combined	$238,531 (number four in top ten constraints with a market impact in Victoria)
T>>T_NIL_BL_EXP_ 7C	66.5	To avoid overload of Farrell to Sheffield 220 kV line for trip of the parallel Farrell to Sheffield 220 kV line considering network control system protection scheme (NCSPS) action, ensure Basslink can fully compensate NCSPS action	$60,884 (number four in top ten constraints with a market impact in Tasmania)
T>>T_NIL_BL_EXP_ 6E	65.8	To avoid overloading a Sheffield to George Town 220 kV line for trip of the parallel Sheffield to George Town 220 kV line considering network control system protection scheme (NCSPS) action	$115,906 (number three in top ten constraints with a market impact in Tasmania)

[a] The market impact is calculated by adding up the marginal values from the marginal constraint cost re-run. To that end, the constraint is relaxed marginally (by 1 MW). This will result in a different dispatch pattern, with different associated costs, compared to the situation under the full constraint. This is done for

each dispatch interval during the number of hours a constraint was binding. These values are subsequently added up to provide a total marginal market impact.

Source: AEMO, *NEM constraint report 2016*, June 2017 and *NEM constraint report 2016 supplementary data*, June 2017.

H.3 Network constraints on the Basslink interconnector

H.3.1 Findings from the 2016 NTNDP

The 2016 NTNDP identifies several projected economic limitations for Tasmania that can impact the Basslink interconnector. They are expected under the neutral and low grid demand scenarios for the forecast period of up to 2035-36. These forecast constraints include:

1. Voltage collapse at George Town when there is high export from Tasmania to Victoria with no gas powered generation units on line in Tamar Valley and reduced number of hydro units in northern Tasmania.

2. Transmission limitations on the George Town to Sheffield 220 kV line. This constraint is expected to emerge during periods of high wind generation from the North West and West Tasmania area and, high Basslink export from Tasmania to Victoria.

3. Transient over-voltage at George Town when there is high export from Tasmania to Victoria with no gas powered generation units on line in Tamar Valley and reduced number of hydro units in northern Tasmania.

4. Basslink inverter commutation instability due to low fault level at George Town. This constraint is expected to occur when there is high import from Victoria to Tasmania via Basslink with low or no gas powered generation units on line in Tamar Valley and low or no hydro units in northern Tasmania.

5. High rate of change of frequency for Tasmania when there is high wind generation in Tasmania and or increased import from Victoria to Tasmania and reduced hydro units on line in Tasmania.

6. High rate of change of frequency for Tasmania when there is unavailability of existing frequency control ancillary services (FCAS) with the retirement of smelters in Tasmania.

The 2016 NTNDP did not identify any reliability or potential economic constraints in Victorian regions that are likely to impact the Basslink interconnector.

H.3.2 Findings from TasNetworks's 2017 Tasmanian transmission annual planning report

In its 2017 Transmission annual planning report (TAPR), TasNetworks proposed an augmentation project to address one of the NTNDP forecast constraints and expressed its awareness of the remaining constraints. TasNetworks also reported that it was engaging with AEMO regarding the remaining constraints and that any augmentation plans to address them would be identified in the future annual planning reports.[147] Since the publication of its TAPR, TasNetworks has provided further information to the Commission regarding its plans to address the relevant limitations forecast by the NTNDP.[148] TasNetworks's plan for addressing the forecast Basslink limitations are as following:

- TasNetworks plans to address the voltage collapse at George Town with an augmentation project. Its TAPR proposed the installation a new 40 MVAr 110 kV capacitor bank at George Town substation to facilitate reactive power compensation. The project will allow the reactive margin at George Town substation to be maintained, ensuring compliance with the NER and maintaining the export capability of Basslink. The estimated project cost is $3.6 million and it is planned to be operational in March 2018. [149] TasNetworks also advised the Commission that dynamic reactive support is also required to assist with this issue.[150]

- In its TAPR, TasNetworks reported that it was familiar with the transmission limitations on George Town to Sheffield 220 kV lines. TasNetworks also advised the Commission that it is preparing a strategic plan for transmission capacity in North West Tasmania which will consider the limitations on George Town to Sheffield 220 kV lines. The plan will also consider the capacity of other lines in the region including Smithton to Burnie 110 kV, Burnie to Sheffield 220 kV, and Sheffield to Palmerston 220 kV lines. [151] Further details of the plan may be included in TasNetworks's upcoming annual planning reports.

- TasNetworks's TAPR reported that it was familiar with the forecast transient over-voltage limitation at George Town. TasNetworks has since advised the Commission that it is considering the inclusion of a 50 MVAr STATCOM for George Town in its next revenue proposal. The STATCOM is proposed to help manage the transient over voltage issues at George Town. It is also envisaged to help provide additional assistance with voltage collapse, help manage phase unbalance issues and potentially facilitate connection of an FFR device. [152]

- TasNetworks's TAPR reported its familiarity with the forecast limitation of Basslink inverter commutation instability due to low fault level at George Town. TasNetworks has since advised the Commission that the issue will be managed through constraint equations and that it is considering a contracting arrangement

147 TasNetworks, *Annual planning report 2017,* June 2017, p79.

148 TasNetworks confirmed this by email on 22 September 2017.

149 Ibid.

150 Ibid.

151 Ibid.

152 Ibid.

with a Tasmanian generator to alleviate the constraint.[153] TasNetworks is in the process of quantifying and assessing the overall benefits of addressing the constraint. There are also relevant constraint equations, which are currently in place to help manage the Basslink inverter commutation instability, e.g. constraint equation with the ID V:T_NIL_BL_1. It was last binding in 2015 with a total of six binding hours in the year and a market impact of $1,329. [154]

- TasNetworks also stated that it was familiar with the forecast limitation of high rate of change of frequency due to high wind generation in Tasmania, increased import from Victoria or reduced online Tasmania hydro units. TasNetworks has advised the Commission that the issue will be managed through constraint equations and that it is looking to limit the impact of network events via the current Tasmanian frequency operating standards review. [155] There are also relevant constraint equations, which are currently in place to help manage the rate of change of frequency, e.g. constraint equations with IDs T_ROCOF_1, T_ROCOF_2 and T_ROCOF_3.[156] T_ROCOF_3 was last binding in 2015 and had a market impact of $577. [157]

- TasNetworks's TAPR also outlined its familiarity with the forecast limitation of high rate of change of frequency due to unavailability of existing frequency control ancillary support (FCAS) services with the retirement of smelters in Tasmania. TasNetworks has advised the Commission that the issue will be managed via constraint equations and that it is looking to limit the impact of network events via the current Tasmanian frequency operating standards review. [158] There are also relevant constraint equations which are currently in place to help manage the rate of change of frequency, e.g. constraint equations with IDs T_ROCOF_1, T_ROCOF_2 and T_ROCOF_3.[159] T_ROCOF_3 was last binding in 2015 and had a market impact of $577.[160]

In Summary, TasNetworks's TAPR identified an augmentation project to address one of these constraints whilst acknowledging its awareness of the remaining constraints. Since the publication of its TAPR, TasNetworks has informed the Commission of its additional plans to address the remaining constraints.

H.3.3 Findings from AEMO's 2017 Victorian transmission annual planning report

Consistent with the 2016 NTNDP, AEMO did not identify any forecast constraints for the Basslink interconnector or the transmission corridors surrounding the

153 Ibid.

154 AEMO, *NEM constraint report 2015 supplementary data*, May 2016

155 TasNetworks confirmed this by email on 22 September 2016.

156 TasNetworks, *Annual planning report 2017,* June 2017, p85.

157 AEMO, *NEM constraint report 2015 supplementary data*, May 2016

158 TasNetworks confirmed this by email on 22 September 2016.

159 TasNetworks, *Annual planning report 2017,* June 2017, p85.

160 AEMO, *NEM constraint report 2015 supplementary data*, May 2016

interconnector in its 2017 Victorian annual planning report (VAPR). Consequently, AEMO has not identified any relevant projects to relieve such constraints on the interconnector or in the surrounding transmission corridor.

H.4 Summary of projects for identified network constraints

The NTNDP identified six potential economic limitations in Tasmania that were deemed relevant for the Basslink interconnector. Through its TAPR and advice provided to the Commission, TasNetworks has outlined plans to address all of the limitations forecast for Basslink in Tasmania. Hence, there are no transmission network constraints on the Basslink interconnector or in the transmission corridors around this interconnector in Victoria and South Australia that are not being addressed by the relevant TNSPs. Table H.2 provides a summary of identified constraint relating to the Basslink interconnector and the TNSP's plans to address them.

Table H.2 Identified constraints relating to the Basslink interconnector and how these are being addressed

Report limitation identified	Constraint details	Project to address constraint	Project status
2016 NTNDP (economic constraint)	Voltage collapse at George Town when there is high export from Tasmania to Victoria	Installation of a new 40 MVAr 110 kV capacitor bank at George Town substation TasNetworks has advised that dynamic reactive support may also be required.	The capacitor bank upgrade is expected to be operational by March 2018
2016 NTNDP (economic constraint).	Transmission limitations on the George Town – Sheffield 220 kV line during periods of high wind generation from the North West and West Tasmania area and high Basslink export from Tasmania to Victoria	TasNetworks is preparing a strategic plan for transmission capacity in north west Tasmania. It will include a plan for the transmission limitation on George Town – Sheffield 220 kV line	Further details of the plan are expected in the upcoming annual planning reports

Report limitation identified	Constraint details	Project to address constraint	Project status
2016 NTNDP (economic constraint)	Transient over-voltage at George Town 220 kV when there is high export from Tasmania to Victoria with no gas powered generation units on line in Tamar Valley and reduced number of hydro units in northern Tasmania	A 50 MVAr STATCOM for George Town in expected in TasNetworks's next revenue proposal. It is expected to help manage the transient over-voltage issue.	TasNetworks's final revenue proposal for the next period is will be submitted to the AER in January 2018.[161]
2016 NTNDP (economic constraint)	Basslink inverter commutation instability due to low fault level at George Town.	TasNetworks is aware of the constraint and is engaging with AEMO regarding it. The issue will be managed by constraint equations. TasNetworks is carrying out assessment and may enter contracting arrangement with a Tasmanian generator to alleviate the constraints. Relevant constraint equations currently exit e.g. V:T_NIL_BL_1	Relevant Constraint equations currently in place, projects may be identified in the upcoming annual planning reports.[162]
2016 NTNDP (economic constraint)	High rate of change of frequency expected when there is high wind generation in Tasmania and or increased import from Victoria to Tasmania and reduced Tasmania hydro units on line.	TasNetworks is aware of the constraint and is engaging with AEMO regarding it. The limitation will be managed by constraint equations. Relevant constraint equations currently exit e.g. T_ROCOF_1, T_ROCOF_2 and T_ROCOF_3.	Relevant constraint equations currently in place, a project may be identified in upcoming annual planning reports.
2016 NTNDP (economic constraint)	High rate of change of frequency expected when there is unavailability of existing frequency control ancillary services (FCAS) with the retirement of smelters in Tasmania.	TasNetworks is aware of the constraint and is engaging with AEMO regarding it. Issue will be managed by constraint equations. Relevant constraint equations currently exit e.g. T_ROCOF_1, T_ROCOF_2 and T_ROCOF_3.	Relevant constraint equations currently in place, a project may be identified in upcoming annual planning reports.

161 TasNetworks 2017, TasNetworks, Hobart, viewed 3 October 2017, https://www.tasnetworks.com.au/our-network/network-revenue-pricing/revenue-proposals/revenue-reset-2019-2024/

162 TasNetworks, *Annual planning report 2017,* June 2017, p79.