Australian Energy Market Commission

FINAL REPORT

LAST RESORT PLANNING POWER - 2018

14 FEBRUARY 2019

REVIEW

INQUIRIES

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

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

Reference: EPR0067

CITATION

AEMC, Last resort planning power 2018, Final Report, 14 February 2019

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

1 The interconnectedness of the transmission network is fundamental to the national electricity market (NEM). It allows electricity to flow across the entire NEM, connecting Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania, and facilitates the NEM as a single market.

2 The last resort planning power (LRPP) is a power conferred on the Australian Energy Market Commission (Commission or AEMC) in the National Electricity Rules (NER) to ensure that sufficient investment is being provided to efficiently transport electricity between adjacent regions of the NEM.

3 The purpose of the LRPP is to "ensure timely and efficient inter-regional transmission investment is being provided for the long term interests of consumers of electricity."[1]

4 Being a last resort mechanism, the LRPP is designed only to be utilised where there is a clear indication that the standard planning processes have resulted in a planning gap regarding the transmission infrastructure for transporting electricity between NEM regions.

5 The Commission must annually assess whether or not it should exercise the LRPP and report on the matters it has considered in deciding whether or not to exercise the LRPP. This assessment must consider the Australian Energy Market Operator's (AEMO's) two most recent National Transmission Network Development Plans (NTNDPs), and transmission network service providers' (TNSPs') transmission annual planning reports to ascertain whether TNSPs are taking appropriate steps to address the future constraints that AEMO identifies for national transmission flow paths (inter-regional constraints).

6 In July 2018, AEMO published the Integrated System Plan (ISP). Consistent with statements in the 2018 ISP that it fulfils the regulatory requirements of an NTNDP, the Commission has taken the 2018 ISP to be the most recent NTNDP for the purposes of the 2018 LRPP review. The Commission has also considered the network transmission projects in the 2018 ISP related to inter-regional flows in this LRPP assessment with a particular focus on the highest priority (Group 1) projects.[2]

7 Under the LRPP, if the AEMC identifies that there are no current processes or projects underway to address a constraint that may significantly impact on the efficient operation of the market, then the AEMC has the power to direct one or more network service providers to apply the regulatory investment test for transmission (RIT-T) to augmentation project(s) that are likely to relieve that expected constraint.

8 The scope of the LRPP review is governed by obligations established in the NER. Under the NER, the Commission must identify and examine transmission network constraints expected to affect electricity flows between NEM regions; both constraints related to limits on the interconnectors' capacity themselves and constraints occurring in parts of the network further

1 Rule 5.22(b) of the NER.

2 AEMO, *Integrated System Plan*, July 2018, p. 15.

removed from the interconnector infrastructure.[3]

9 The Commission has completed the LRPP review for 2018. The Commission has concluded that TNSPs, including AEMO as the Victorian transmission planner, are adequately considering inter-regional constraints in the NEM that have been identified by AEMO (in its role as the national transmission network planner). There is no evidence of insufficient consideration of an inter-regional transmission constraint that would require the Commission to direct a TNSP under its LRPP. The Commission has therefore decided not to exercise the LRPP for 2018.

10 Regulatory processes are already underway for all 2018 ISP Group 1 projects and some 2018 ISP Group 2 projects, including in relation to the Queensland - NSW interconnector (QNI), Victoria - NSW interconnector (VNI) and the new South Australia - NSW interconnector (Project EnergyConnect, formerly Riverlink).[4]

11 The Commission's decision is based on the following findings regarding inter-regional flows between NEM regions:

- Queensland to New South Wales, including inter-regional constraints relevant to QNI: AEMO has identified three expected inter-regional constraints on QNI. TransGrid and Powerlink are proposing five potential options to augment QNI in their November 2018 RIT-T Project Specification Consultation Report (PSCR) with each option comprising a suite of projects. Each of the expected constraints are addressed by these options and projects. AEMO has not forecast any inter-regional constraints involving the Terranora interconnector.
- Victoria to New South Wales, including inter-regional constraints relevant to VNI: AEMO has identified eight expected inter-regional constraints on VNI. TransGrid and AEMO have proposed several options to address each of these inter-regional constraints in their November 2018 RIT-T PSCR and their respective annual planning reports.
- Victoria to South Australia, including all inter-regional constraints relevant to the Heywood interconnector and the Murraylink interconnector: AEMO has identified one expected inter-regional constraint on the Heywood interconnector. ElectraNet is currently considering four transmission development projects to address this constraint. AEMO has identified one expected inter-regional constraint on the Murrylink interconnector. ElectraNet completed the uprating of the Riverland lines in August this year and is considering two further projects to address this constraint.
- Tasmania to Victoria, including all inter-regional constraints relevant to the Basslink interconnector: AEMO has identified seven expected inter-regional constraints on the Basslink interconnector. TasNetworks has proposed solutions to address all of these constraints.

12 Table 1 details the expected inter-regional constraints across the transmission network associated with each interconnector and the solutions proposed to address each of these constraints.

3 Rule 5.22(g) of the NER.

4 Group 1 projects are projects AEMO considers require immediate investment, with completion as soon as practicable. Group 2 projects are projects AEMO considers require action to be taken now, to initiate work on projects for implementation by the mid-2020s. The term 'Riverlink' is used for the purposes of this report.

13 The Commission has conducted this 2018 LRPP assessment in accordance with the requirements in the NER and with the LRPP guidelines. In making its decision the Commission has considered:

- The 2016 NTNDP published by AEMO in December 2016, the 2018 Integrated System Plan (ISP) published by AEMO in July 2018, and supplementary information provided to the Commission by AEMO.
- The 2018 transmission annual planning reports (TAPRs) for each region of the NEM published by TNSPs and relevant RIT-T reports including recent PSCRs.
- The NEM constraint summary data for 2017 published by AEMO.

14 On 21 December 2018, AEMO published a 2018 NTNDP. The plan details the current status of major proposed transmission infrastructure, including interconnector upgrades. Many of the inter-regional constraints and transmission proposals discussed in the 2018 NTNDP are considered in this 2018 LRPP review as they were identified in either the 2016 NTNDP and/or the 2018 ISP.[5] Consistent with previous practice, the Commission will consider whether TNSPs are addressing all the inter-regional constraints that AEMO identifies in the 2018 NTNDP in the Commission's 2019 LRPP review following TNSPs' publication of their 2019 annual planning reports, due by June 2019.

15 The Commission will continue to use the LRPP process to monitor inter-regional constraints and the progress of projects identified as part of the 2018 ISP, as recommended by the Energy Security Board (ESB) in its recent ISP advice to the COAG Energy Council in December 2018.[6] The Commission also notes that the Integrated System Plan Action Plan submitted by the ESB to the COAG Energy Council in December 2018 recommended that if a 2018 ISP Group 2 or 3 project is considered by AEMO and the ESB to be behind schedule, the COAG Energy Council should request that the Commission direct a party to commence its RIT-T process through the Commission's LRPP.[7]

5 For more details, see AEMO, *National Transmission Network Development Plan*, December 2018, p. 28.

6 Energy Security Board, *Integrated System Plan; Action Plan*, December 2018.

7 Recommendation 7 from Energy Security Board, *Integrated System Plan; Action Plan*, December 2018.

Table 1: **Summary of identified constraints affecting inter-regional flows in the NEM and projects proposed by TNSPs to address each constraint**

INTER-REGIONAL CONSTRAINT IDENTIFIED BY AEMO	PROJECT(S) TO ADDRESS CONSTRAINT	PROJECT COST AND TIMING
QNI #1: New South Wales to Queensland export is limited by a voltage collapse limit on loss of the largest generating unit in Queensland.	Several options proposed in TransGrid and Powerlink's RIT-T PSCR could address this constraint. Installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks are AEMO 2018 ISP Group 1 projects.	Indicative cost of PSCR options ranges from $114 million to $2.1 billion depending on the option chosen. Expected delivery time varies between 2-3 years and 5-6 years. Project selection to be determined.
QNI #2: New South Wales to Queensland export is limited by the thermal capacity of Liddell - Muswellbrook - Tamworth and Liddell - Tamworth 330 kV lines.	Several options proposed in TransGrid and Powerlink's RIT-T PSCR could address this constraint. Uprating the Liddell to Tamworth lines is an AEMO 2018 ISP Group 1 project.	Indicative cost of PSCR options ranges from $28 million to $2.1 billion depending on the option chosen. Expected delivery time varies between 2-3 years and 5-6 years. Project selection to be determined.
QNI #3: Queensland to New South Wales export is mainly limited by the transient stability limits for a fault on either a Bulli Creek -Dumaresq or Armidale - Dumaresq 330 kV circuit.	Several options proposed in TransGrid and Powerlink's RIT-T PSCR could address this constraint. Installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks are AEMO 2018 ISP Group 1 projects.	Indicative cost of PSCR options ranges from $45 million to $2.1 billion depending on the option chosen. Expected delivery time varies between 1-2 years and 5-6 years. Project selection to be determined.

<table>
<tr><th>INTER-REGIONAL CONSTRAINT IDENTIFIED BY AEMO</th><th>PROJECT(S) TO ADDRESS CONSTRAINT</th><th>PROJECT COST AND TIMING</th></tr>
<tr><td>VNI #1:

Victorian exports to New South Wales limited by transmission limitations on the Sydney to Canberra/Yass 330 kV corridor.</td><td rowspan="2">Several options proposed in AEMO and TransGrid's RIT-T PSCR could address these constraints. These include uprating the Canberra - Upper Tumut line, which is an AEMO ISP Group 1 project.</td><td rowspan="2">Indicative cost of PSCR options ranges from $28 million to $520 million depending on the option chosen. Expected delivery time varies between 27 months and 63 months.

Project selection to be determined.</td></tr>
<tr><td>VNI #2:

Flows towards New South Wales are limited by the thermal capacity of the Upper Tumut - Canberra 330 kV line.</td></tr>
<tr><td>VNI #3:

Transmission limitation on South Morang 500/330kV transformer.</td><td>Several options proposed in AEMO and TransGrid's RIT-T PSCR could address this constraint. These include an additional 500/330 kV transformer(s) at South Morang, which is an AEMO 2018 ISP Group 1 project.</td><td>The indicative costs of PSCR options are $29 million. Expected delivery time is 36 months.

Project selection to be determined.</td></tr>
<tr><td>VNI #4:

Transmission limitations on Dederang - South Morang 330 kV circuits.</td><td>Several options proposed in AEMO and TransGrid's RIT-T PSCR could address this constraint. These include uprating the South Morang - Dederang lines, which is an AEMO 2018 ISP Group 1 project.</td><td>Indicative cost of PSCR options ranges from $17 million to $370 million depending on the option chosen. Expected delivery time varies between 30 months and 60 months.

Project selection to be determined, as well as costs and indicative timing of one of the options.</td></tr>
</table>

INTER-REGIONAL CONSTRAINT IDENTIFIED BY AEMO	PROJECT(S) TO ADDRESS CONSTRAINT	PROJECT COST AND TIMING
VNI #5: Flows towards New South Wales are limited by the transient stability limit for a 2 phase to ground fault on a South Morang - Hazelwood 500 kV line.	Several options proposed in AEMO and TransGrid's RIT-T PSCR could address this constraint. These include a braking resistor, battery storage or a Flexible Alternating Current Transmission System (FACTS) device, which are AEMO 2018 ISP Group 1 projects.	Indicative cost of PSCR options ranges from $13 million to $20 million depending on the option chosen. Expected delivery time varies between 24 months and 30 months. Project selection to be determined, as well as costs of one of the options.
VNI #6: New South Wales to Victoria import is limited by thermal capacity of the Murray - Dederang 330 kV line.	Several projects being considered by AEMO in its Victorian annual planning report (VAPR) could address this constraint. None of these projects are AEMO 2018 ISP Group 1 projects.	Indicative cost of VAPR options ranges from $152 million to $183.9 million depending on the option chosen. Project selection and project timing to be determined.
VNI #7: New South Wales to Victoria import is limited by thermal capacity of the Eildon - Thomastown 220 kV line.	Several projects being considered by AEMO in its VAPR could address this constraint. None of these projects are AEMO 2018 ISP Group 1 projects.	Indicative cost provided for one of the VAPR options is $44.6 million. Project selection and project timing to be determined, as well as costs of one of the options.
VNI #8: Transmission limitations on Dederang – Mt. Beauty 220 kV lines.	Several projects being considered by AEMO in its VAPR could address this constraint. None of these projects are AEMO 2018 ISP Group 1 projects.	Indicative cost of one VAPR option is $12.4 million. Project selection and project timing to be determined, as well as costs of one of the options.

INTER-REGIONAL CONSTRAINT IDENTIFIED BY AEMO	PROJECT(S) TO ADDRESS CONSTRAINT	PROJECT COST AND TIMING
Heywood #1: Transmission limitations on the Tailem Bend – Tungkillo transmission corridor.	Several projects being considered by ElectraNet in its TAPR could address this constraint. None of these projects are AEMO 2018 ISP Group 1 projects.	Indicative cost of TAPR projects ranges from $3 million to $1.5 billion depending on the project. Expected delivery time varies between June 2019 and 2024.
Murraylink #1: Transmission limitations on 132 kV network in the Riverland region of South Australia.	Several projects being considered by ElectraNet in its TAPR could address this constraint. None of these projects are AEMO 2018 ISP Group 1 projects. Uprating the Robertstown to North West Bend No. 2 132 kV line and the North West Bend to Monash 132 kV line from 80°C design clearances to 100°C design clearances has been completed.	Indicative cost of TAPR projects ranges from less than $5 million to $1.5 billion depending on the project. Expected delivery time varies between June 2022 and 2024.
Basslink #1: Transmission limitations on the Palmerston – Sheffield 220kV line.	The project proposed in TasNetworks' TAPR to address this constraint is constructing a new Palmerston - Sheffield 220 kV transmission line. This is not an AEMO 2018 ISP Group 1 project.	An indicative TAPR cost of $120 million. No project timing provided; the proposed trigger for this project is currently subject to approval by the AER.
Basslink #2: Transmission limitations on the George Town to Sheffield 220 kV line.	The project proposed in TasNetworks' TAPR to address this constraint is a second Basslink interconnector. An interim plan is for generation or Basslink export to be reduced as required. Neither of these projects are AEMO 2018 ISP Group 1 projects.	A second Basslink interconnector has an indicative TAPR cost of $1100 million. The project is currently subject to the RIT-T process. No indicative costs or timing are provided for the interim solution.
Basslink #3:	Several projects being considered by	The capacitor bank was completed by

INTER-REGIONAL CONSTRAINT IDENTIFIED BY AEMO	PROJECT(S) TO ADDRESS CONSTRAINT	PROJECT COST AND TIMING
Voltage collapse at George Town.	TasNetworks in its TAPR could address this constraint. None of these projects are AEMO 2018 ISP Group 1 projects. One project, a 40 MVAr capacitor bank at George Town Substation, has been completed.	TasNetworks in March 2018. Indicative cost of the remaining TAPR option is $15.1 million. It is expected to be operational by June 2022.
Basslink #4: Over-voltage at George Town.		
Basslink #5: Basslink inverter commutation instability due to low fault level at George Town.	The project proposed in TasNetworks' TAPR to address this constraint is investigating with relevant customers to include frequency control services as part of the proposed Static Synchronous Compensator (STATCOM) at George Town Substation. This is not an 2018 ISP AEMO Group 1 project.	No cost or indicative timing has been indicated.
Basslink #6: High Rate of Change of Frequency (RoCoF) 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.		
Basslink #7: High RoCoF for Tasmania for unavailability of existing frequency control ancillary services (FCAS) with the retirement of smelters in Tasmania.	TasNetworks continues to engage with their major industrial customers and does not anticipate the near-term closure of Tasmanian smelters. This is not an AEMO 2018 ISP Group 1 project.	No cost or indicative timing has been indicated.

CONTENTS

TABLES

FIGURES

1 INTRODUCTION

The national electricity market (NEM) is one of the longest interconnected power systems in the world. It comprises almost 40,000km of transmission lines across six Australian states and territories. The ability to transfer electricity between Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania and South Australia is fundamental to the operation of the NEM as a single wholesale electricity market.

The Australian Energy Market Commission (Commission or AEMC) holds a last resort planning power (LRPP), conferred on it in the National Electricity Rules (NER), to ensure that sufficient investment in transmission infrastructure is occurring to transport electricity across the NEM. This power enables the AEMC to direct a network business to undertake a regulatory investment test - weighing up the costs and benefits of investment - on projects to address network congestion, if they are not already underway.

The AEMC must annually assess and report on whether it should exercise the LRPP.[8] This report meets that obligation by describing the matters the Commission has taken into account when undertaking the 2018 LRPP review and the Commission's decision on whether to exercise the LRPP in respect to 2018.

Chapter 2 of this report explains the LRPP. It outlines the purpose of the LRPP and the obligations on the Commission in conducting the annual review. It also describes the bearing on this 2018 LRPP review of: the Australian Energy Market Operator (AEMO)'s 2018 Integrated System Plan (ISP); the December 2018 report by the Energy Security Board (ESB) to the Council of Australian Governments (COAG) Energy Council and; the December 2018 final report of the Commission's biennial review into the Coordination of generation and transmission investment (CoGaTI).

Chapter 3 of this report describes the interconnected nature of the NEM and why the ability to transfer electricity flows between regions is vital to its operation. It explains key concepts related to congestion in the transmission network, such as interconnectors and inter-regional constraints, and presents data on recent inter-regional flows and inter-regional congestion. It highlights that interconnection has costs and for that reason the benefits need to be balanced against the increased costs, which are largely paid for by consumers.

Chapter 4 of this report outlines the data sources the Commission analysed in undertaking the 2018 LRPP review. Chapters 5 to 8 in turn list the constraints that AEMO expects to affect the flows of electricity between NEM regions. Each chapter then assesses if the expected inter-regional constraints are being addressed by the relevant transmission network service provider (TNSP), and evaluates whether there is evidence of insufficient consideration of an inter-regional constraint that would require the Commission to direct a TNSP under its LRPP.

8 Rule 5.22(m) of the NER.

2 BACKGROUND

2.1 Purpose and scope of the LRPP

The LRPP is a power conferred on the Commission in the NER to ensure that sufficient investment is being provided to transport electricity between adjacent regions of the NEM, which is fundamental to the efficient operation of the NEM.

The purpose of the LRPP is to:[9]

> ensure timely and efficient inter-regional transmission investment is being provided for the long term interests of consumers of electricity.

The transmission network in the NEM is critical for facilitating a reliable supply of electricity to consumers. It allows electricity to be bought and sold across Australia's eastern and south-eastern states.[10]

Responsibility for planning the transmission network is generally shared between AEMO, in its role as national transmission planner, and TNSPs.[11] This planning governance framework is supplemented by the Commission's LRPP.

Under the LRPP if the AEMC identifies that there are no current processes or projects underway to address a constraint that may significantly impact on the efficient operation of the market, then the AEMC has the power to direct one or more network service providers (typically a TNSP) to apply the regulatory investment test for transmission (RIT-T) to augmentation project(s) that are likely to relieve that expected constraint.[12] The NER in conjunction with the AER's November 2018 determination on cost thresholds require TNSPs to apply a RIT-T for any projects with an estimated cost of more than $6 million.[13] This applies to both augmentation and replacement expenditure.[14]

Because the LRPP is a power that can be used as a last resort mechanism to ensure that all significant inter-regional transmission constraints are being addressed in the transmission planning process, the LRPP examines any potential transmission projects that could address expected inter-regional constraints.

The LRPP is not a power to direct that investment in the transmission network be made. Rather it is the power to direct that the RIT-T be applied to a project that is designed to address an identified problem. The referred project or projects could be identified by the AEMC or the network service provider, or based on advice by AEMO.

9 Under clause 5.22(b) of the NER.

10 As well as the Australian Capital Territory.

11 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 NER.

12 Under rules 5.22(h), 5.22(i), and 5.22(k) of the NER.

13 Clause 5.15.3(a)(2) of the NER. See also AER, *Final determination - Cost thresholds review*, November 2018, p. 4.

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

Being a last resort mechanism, the LRPP is designed to only be utilised where there is a clear indication that the standard planning processes have resulted in a planning gap regarding the network transmission infrastructure for transporting electricity between NEM regions.

The Commission must report annually on the matters which it has considered during the year in deciding whether or not to exercise the LRPP.[15] This report meets that obligation by specifying the matters the Commission has considered, and its decision, regarding whether to exercise the LRPP in 2018.

2.2 The Commission's approach

The Commission must decide whether, and if so how, to exercise the LRPP in accordance with requirements in the NER and with the LRPP guidelines (guidelines).[16] The obligations pertaining to the LRPP are established in rule 5.22 of the NER and the guidelines. These obligations have directed the Commission's assessment approach in 2018.

2.2.1 Obligations under the NER

In conducting its assessment of whether there is a need to exercise the LRPP, the NER requires the Commission to consider:[17]

> (1) [any] advice provided by AEMO;
>
> (2) the NTNDP [National Transmission Network Development Plan] for the current and the previous year;
>
> (3) Transmission Annual Planning Reports [TAPRs] published by Transmission Network Service Providers under clause 5.12.2; and
>
> (4) other matters that are relevant in all the circumstances.

The NER also defines a number of criteria related to the exercise of the LRPP. Rule 5.22(g) of the NER specifies that before it can exercise the LRPP, the AEMC must:

> (1) identify a problem relating to constraints in respect of national transmission flow paths between regional reference nodes or a potential transmission project (the problem or the project)
>
> (2) make reasonable inquiries to satisfy itself that there are no current processes underway for the application of the regulatory investment test for transmission in relation to the problem or the project;

15 Rule 5.22(m) of the NER. Previous LRPP reports are available on the AEMC website. The AEMC may include the LRPP information in its annual report (under rule 5.22(m) of the NER). The AEMC has traditionally chosen to publish a separate report on the issue.

16 Rule 5.22 of the NER.

17 Under rule 5.22(f) of the NER. The Commission may request advice from AEMO in relation to the exercise of the last resort planning power, in accordance with the last resort planning power guidelines, rule 5.22(e) of the NER. Chapter 4 details the information sources analysed for this 2018 LRPP assessment.

> (3) consider whether there are other options, strategies or solutions to address the problem or the project, and must be satisfied that all such other options are unlikely to address the problem or the project in a timely manner;
>
> (4) be satisfied that the problem or the project may have a significant impact on the efficient operation of the market; and
>
> (5) be satisfied that but for the AEMC exercising the last resort planning power, the problem or the project is unlikely to be addressed.

The NER defines a national transmission flow path as:

> that portion of a transmission network or transmission networks used to transport significant amounts of electricity between generation and load centres.

Constraints relating to national transmission flow paths between regional reference nodes are termed "inter-regional constraints" in this report.

2.2.2 Obligations under the guidelines

The Commission also must conduct its assessment of the need to exercise the LRPP in accordance with the guidelines.[18] The guidelines specify processes that must be followed, regarding information provision to the AEMC (by AEMO, network service providers and other parties), consultation and communication.[19]

The guidelines also set out a three-stage LRPP assessment process for undertaking the annual LRPP assessment.[20] Progression from one stage to the next depends on the findings of the preceding stages.

The first stageinvolves reviewing relevant planning documents to determine whether there are any constraints regarding national transmission flow paths (i.e. inter-regional constraints) that have not been adequately examined by network service providers, i.e. assessing whether there are any potential planning 'gaps'. The guidelines recommend the Commission analyse the following data sources in addition to those sources stipulated by the NER; the 'most recent congestion information resource published by AEMO' and 'any other relevant documents, such as any RIT-T reports'.[21]

The second stage of the Commission's LRPP assessment involves more closely examining the identified gaps to determine whether exercising the LRPP is likely to meet the national electricity objective.[22]

18 Rule 5.22(d) of the NER. The AEMC publishes and maintains the guidelines. Rules 5.22(o) and 5.22(q) of the NER.

19 The matters to be addressed in the guidelines are set out in rule 5.22(n) of the NER. The guidelines are available at https://www.aemc.gov.au/sites/default/files/2018-02/Last-resort-planning-power-guidelines-FOR-PUBLICATION.pdf

20 AEMC, *Last resort planning power guidelines*, 24 September 2015, p. 2-3.

21 The wording in the Guidelines is that the "AEMC will generally and analyse and compare the following documents..." The requirements in the NER requiring consideration of the two most recent NTNDPs and the transmission annual planning reports would over-ride the guidelines. ibid, p. 2.

22 Only undertaken if any planning gaps have been identified in stage one.

The third stagefocuses on who should be directed to undertake a RIT-T.[23] If the Commission decides that exercising the LRPP is necessary, it must provide a direction notice to a TNSP stating the action that the TNSP is required to undertake and the AEMC's reasons for exercising the LRPP. The TNSP must comply with the requirement to carry out a RIT-T.[24]

Table 2.1 summarises the respective roles of market bodies and participants under the LRPP framework.

Table 2.1: LRPP - Roles of market bodies and market participants under the NER

AEMC	Last resort planner - The AEMC has the LRPP to direct TNSPs to carry out relevant transmission planning if determined to be necessary. The AEMC must refer to information provided on the state of the transmission network by AEMO and the TNSPs, and can request information from both parties in order to determine whether exercising the LRPP is necessary.
AEMO	National transmission planner - AEMO must publish an annual report on the development of the NEM transmission grid as part of its role as the national transmission planner under the National Electricity Law (NEL).[1] This is informed by AEMO's consultation with the TNSPs and provides input to the LRPP regarding congestion on inter-regional flows in the transmission network. Victorian transmission network planner - AEMO also publishes the Victorian Annual Planning Report (VAPR) on the state of the transmission network in Victoria and the projects it plans for the network in its role as the Victorian transmission planner.[2] The VAPR provides input to LRPP considerations regarding projects designed to resolve inter-regional constraints concerning the Victorian transmission network.
TNSPs	Regions' transmission network planners **-** TNSPs publish TAPRs on the state of their transmission network and planned projects for the network. TAPRs provide input to LRPP considerations regarding projects designed to resolve inter-regional constraints concerning various state transmission networks in the NEM.
AER	Economic regulator - The AER administers the regulatory investment test for transmission (RIT-T). RIT-Ts can provide input to LRPP considerations regarding projects designed to resolve inter-regional constraints.

Note: 1 - Under section 49(2) of the NEL and rule 5.20(2) of the NER.
2 - Under rule 5.12 of the NER.

23 Only undertaken if any planning gaps have been identified in stage one.

24 Rule 5.22(k)(3) of the NER.

2.3 Recent developments

Several recent developments regarding transmission planning and investment have been pertinent to the conduct of this 2018 LRPP review.

2.3.1 Implications of the 2018 ISP

As outlined previously, under the NER the Commission must consider AEMO's current NTNDP and previous NTNDP in the Commission's annual assessment of whether it is necessary to exercise the LRPP.

In late 2017, AEMO modified arrangements for the publication of the 2017 NTNDP. AEMO is required under the NER to publish a NTNDP by 31 December each year, for the following year. AEMO delayed publication of the 2017 NTNDP and integrated it into an ISP, which was published in July 2018. The 2018 ISP's purpose and scope are intended to encompass the issues which would normally be in the NTNDP, while also responding to a 'Finkel review' recommendation for an Integrated Grid Plan.[25]

The Commission has taken the 2018 ISP to be the current NTNDP for the purposes of the 2018 LRPP review (see chapter 4 for more information on the sources analysed for this review).

On 21 November 2018 the AEMC sought confirmation from AEMO, in its role as national transmission planner, of the inter-regional transmission constraints which AEMO considers need to be addressed by the relevant TNSPs. AEMO responded to the Commission's request on 27 November 2018.[26] This supplemented information provided by AEMO staff to the AEMC in September 2018.

The current NER-based cycle (and schedule) of data published by AEMO informs TNSPs' annual planning and is an important feature of transmission planning in the NEM and fundamental to the LRPP. The timing of the 2018 ISP's publication in July meant that it was not available in time for TNSPs to directly take it into account in their 2018 TAPRs (which must be published by 30 June each year). As part of considering the future role and design of the ISP, it will be important to consider these timing issues and the interaction between the ISP, TAPRs and the LRPP.

On 21 December 2018, AEMO published a 2018 NTNDP, that updates some of the information contained in the 2018 ISP. The Commission will assess whether TNSPs are addressing the inter-regional constraints that AEMO has identified in the 2018 NTNDP in the Commission's 2019 LRPP review after TNSPs publish their 2019 TAPRs, due 30 June 2019 (see section 4.1 for more information on the 2018 NTNDP).[27]

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25 Finkel et al., *Independent Review into the Future Security of the National Electricity Market*, June 2017, Recommendation 5.1, p. 264.

26 The Commission also sought details from TransGrid of how it intended to address the inter-regional constraints on the Queensland - NSW interconnector, as well as the timing for the processes to address those constraints. TransGrid responded to the Commission on 23 November 2018.

27 AEMO, *National Transmission Network Development Plan*, December 2018, p. 28.

2.3.2 The Energy Security Board and the Commission's CoGaTI review

On 21 September 2018, COAG tasked the Chair of the ESB with developing a work program to 'convert the ISP into an actionable strategic plan'.[28] In December 2018, the ESB reported back to the COAG Energy Council on how major projects identified in the 2018 ISP can be delivered or progressed. The ESB also outlined to COAG Energy Council its preferred plan and recommendations to make the ISP an actionable strategic plan.[29] The ESB recommended that the Commission should be requested to use its LRPP to direct a party to commence a RIT-T process if, in the future, AEMO and the ESB consider that a 2018 ISP Group 2 or 3 Project is behind its required timing.[30] This ESB recommendation endorses the LRPP continuing to be an important part of the transmission planning framework going forward.[31]

The Commission also published the final CoGaTI report on 21 December 2018.[32] The CoGaTI review has been developed following a request from the COAG Energy Council that the Commission undertake a biennial reporting regime on a set of drivers that could impact on future transmission and generation investment. The 2018 CoGaTI review was an input to the Chair of the ESB's report to the COAG Energy Council, and provides a comprehensive reform package and implementation work plan to better coordinate investment in renewable generation and transmission infrastructure in the NEM.

In regards to the LRPP, the CoGaTI review recommended that the power should remain with the AEMC as a "safety net" for the transmission planning and investment decision framework, and could be used if necessary for directing a TNSP to consider a particular investment in detail through a streamlined RIT-T process.

28 COAG Energy Council, *Energy Security Board- Converting the Integrated System Plan into Action,* September 2018, p. 4.

29 Energy Security Board, *Integrated System Plan; Action Plan*, December 2018.

30 Recommendation 7, ibid, p. 5.

31 Recommendation 7, ibid.

32 AEMC, *Coordination of Generation and Transmission Investment,* Final Report, 21 December 2018.

3 INTERCONNECTION AND CONSTRAINTS

3.1 Interconnection in the NEM

3.1.1 The importance of inter-regional transfers

The NEM is one of the longest interconnected power systems in the world. Almost 40,000km of transmission lines and associated infrastructure make up the NEM transmission network.

The ability to transfer electricity between the eastern and south-eastern states of Australia is fundamental to the operation of the NEM as a wholesale electricity market. Interconnection allows electricity to flow across the entire network—geographically connecting Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania—and facilitating the NEM as a single market.

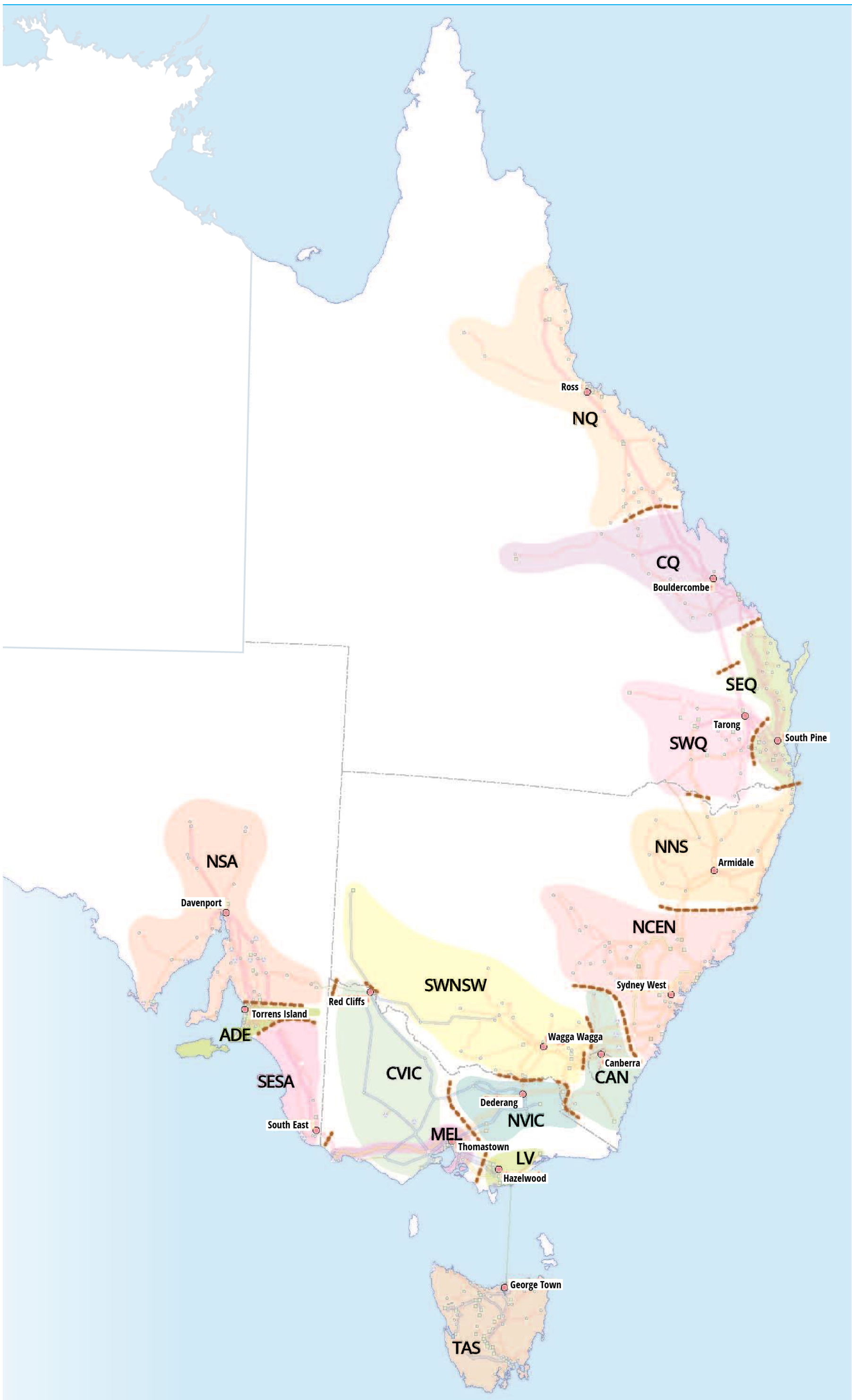
The NEM is divided into five regions which approximately follow the state boundaries: Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia and Tasmania. The five interconnected states act as price regions in the NEM. For planning purposes the NEM is further broken up into sixteen national transmission zones, shown in Figure 3.1 and Figure 3.2. These transmission zones are used for transmission planning and a range of modelling studies.

Figure 3.1: National Transmission zones in the NEM

Region	Zones
QLD (Queensland)	NQ (North Queensland)
	CQ (Central Queensland)
	SWQ (South West Queensland)
	SEQ (South East Queensland)
NSW (New South Wales)	NNS (Northern New South Wales)
	NCEN (Central New South Wales)
	CAN (Canberra)
	SWNSW (South West New South Wales)
VIC (Victoria)	LV (Latrobe Valley)
	MEL (Melbourne)
	CVIC (Country Victoria)
	NVIC (Northern Victoria)
SA (South Australia)	ADE (Adelaide)
	NSA (Northern South Australia)
	SESA (South East South Australia)
TAS (Tasmania)	TAS (Tasmania)

Source: AEMO, *Market Modelling and Input Assumptions*, December 2016, pp. 11-12.

Figure 3.2: Map of National Transmission zones in the NEM



Source: Based on chart from AEMO, *Market Modelling and Input Assumptions*, December 2016, pp. 11-12.

Network interconnection has a number of efficiency benefits, which serve the long term interests of consumers. It:[33]

- Can allow electricity in lower priced regions to flow to higher priced regions. This reduces the cost of meeting demand in the NEM and the degree of price separation between regions.
- Can help dampen price volatility within regions.
- Allows investment in generation and transmission to be optimised. 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 electricity supply and demand response.

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

- Sources of renewable energy are often geographically further removed from centres of demand than conventional generation.
- There is 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 may increase as a result of lower variable-cost renewable energy in some regions.
- The intermittency of some renewable energy sources such as wind and solar (without storage) in some circumstances may require sources of energy or load that can respond to instructions to increase or decrease output or usage to facilitate a reliable power supply.[34] This may be provided by sources located in another region.

However, interconnection also has costs and the above benefits need to be balanced against the costs of increased interconnection. With the exception of the Basslink interconnector between Tasmania and Victoria, all current interconnectors in the NEM are regulated and paid for by consumers through transmission network charges.[35]

3.1.2 Historical inter-regional flows

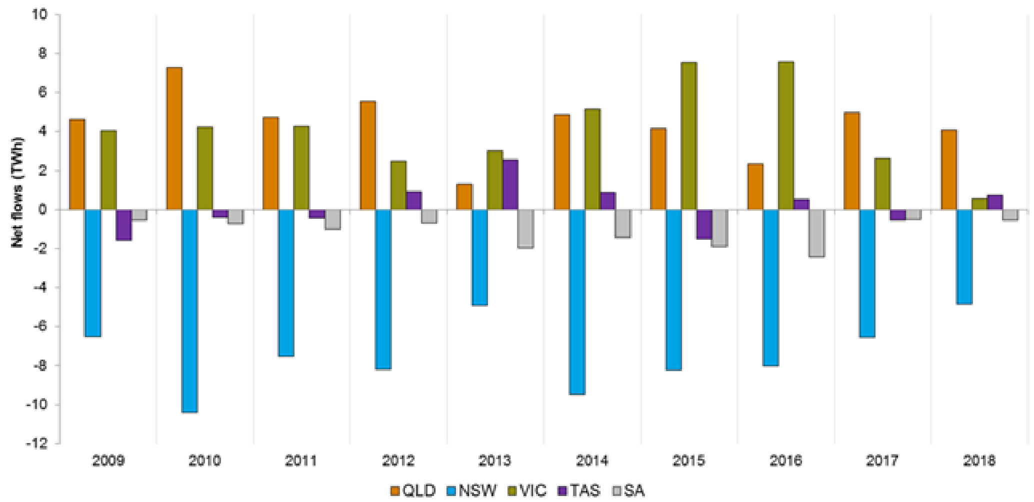
The level of interconnection in the NEM has facilitated inter-regional trade between NEM regions. Depending on local circumstances – such as available generation, the cost of generation and levels of demand – regions are either net importers or net exporters of electricity. Figure 3.3 shows inter-regional trade in net flows for each region of the NEM from 2009 - 2018.

33 See also: Productivity Commission, *Electricity Network Regulation*, Final Report, Chapter 18: The role of interconnectors, 9 April 2013.

34 AEMC, *Reliability frameworks review*, Final report, 26 July 2018, p. 62.

35 See Box 1 for more information on how interconnectors are regulated.

Figure 3.3: Net inter-regional flows in the NEM (2009 - 2018)



Source: AEMC analysis of MMS database.

Note: A positive net flow indicates that the region was exporting electricity in aggregate over the entire year. A negative net flow indicates that the state was importing electricity in aggregate over the entire year.

3.1.3 Interconnectors

In the context 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.

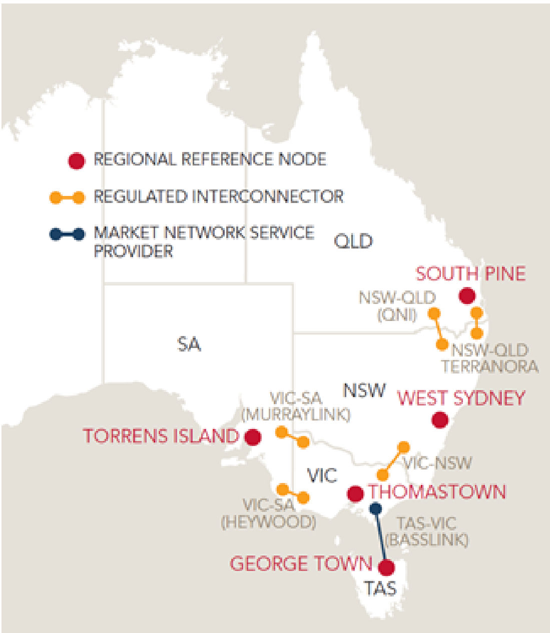
Six interconnectors (often incorporating a number of high voltage transmissions lines) transport electricity between adjacent NEM regions. Table 3.1 lists the interconnectors along with their regions, flow path and name. The Queensland - NSW (QNI) interconnector, Victoria - New South Wales (VNI) interconnector and Heywood interconnector are high voltage alternating current (HVAC) links while Terranora, Murraylink and Basslink are high voltage direct current (HVDC) links.

Table 3.1: NEM interconnectors and their flow paths

REGION	NAME	FLOW PATH
New South Wales - Queensland	QNI	NNS - SWQ
New South Wales - Queensland	Terranora (formerly Directlink)	NNS - SEQ
Victoria - New South Wales	VNI (Vic - NSW)	NVIC - SWNSW, CVIC - SWNSW
Victoria - South Australia	Heywood	MEL - SESA
Victoria - South Australia	Murraylink	CVIC - ADE
Tasmania - Victoria	Basslink	LV - TAS

Figure 3.4 illustrates where the interconnectors are physically located.

Figure 3.4: Location of interconnectors in the NEM



Source: AEMO, *An introduction to Australia's National Energy Market*, July 2010, p. 15.

> **BOX 1: HOW INTERCONNECTORS ARE REGULATED**
>
> Interconnectors in the NEM are either regulated or market (unregulated).
>
> 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 TNSPs owning the interconnector include the value of the interconnector assets in their regulatory asset base, and their maximum annual revenue set by the AER 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 RIT-T when planning for the building of a new regulated interconnector or increasing the capacity of an existing regulated interconnector.[1]
>
> 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. New or expanded 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.
>
> Note: 1 - The RIT-T is discussed in more detail in section 4.4 of this report.

3.2 Congestion and inter-regional constraints

3.2.1 Congestion in the transmission network

Limits exist on the transmission network's ability to carry electricity. If the limits on a particular part of the network are reached so that the power flows are constrained to levels less than what an unconstrained efficient dispatch would suggest, then there is said to be congestion on that part of the network.

Congestion on the transmission network has a cost.[36] Congestion generally results in the dispatch of more expensive generation than otherwise would have been the case and very occasionally, curtailment of loads.[37] The cost of congestion is typically considered in terms of:

- The total time over a fixed period for which flows were constrained to levels below what an efficient dispatch would suggest (eg. hours/year).[38]
- The estimated marginal cost of a constraint on total dispatch costs (marginal value).

36 In theory, congestion may be eliminated if sufficient money was spent on expanding, or upgrading transmission network infrastructure. However, the cost of doing this may outweigh the costs incurred from the congestion itself. In this sense, congestion occurs not only because of the network's physical limitations, but also because of economic considerations of net costs and benefits. In other words, some level of congestion is likely to be economically efficient. Network congestion also impacts on the ability of NEM participants to manage risks associated with inter-regional trade.

37 Congestion in the network can result in certain sources of generation being 'constrained off' from other parts of the network.

38 Importantly, the amount of time that a constraint equation is binding only provides information regarding how long generator outputs or flows on one or more interconnectors have been constrained. It does not indicate the economic costs of this congestion.

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

- Thermal limits, which refer to the heating of a transmission element. The heating of transmission lines, for example, increases as more power is sent across them. This heating may cause the lines to sag closer to the ground, which may encroach on statutory ground clearances. Thermal limits are used for managing the power flow on a transmission element so that it does not exceed a certain rating.
- Stability limits, which include limits to keep generating units operating synchronously and in a stable manner.
- Voltage limits, which involve maintaining voltage magnitudes at acceptable limits.
- Other limits, including those arising from requirements for adequate amounts of frequency control ancillary services (FCAS).

Violating these limits may damage equipment, may lead to supply interruptions and could ultimately be hazardous for the general public.

Allowances must be made to ensure that the transmission elements of the system do not exceed their operational limits, including following credible contingency events.

Importantly, congestion on the transmission network can be influenced by events occurring far away from the physical line that is constrained. Consequently, flows across the interconnectors and the capacity for inter-regional trade in the NEM are not only influenced by the limits of the interconnector(s) capacity itself, but also by constraints occurring in parts of the network further removed from the actual interconnector infrastructure. In this report, congestion anywhere on the transmission network that impacts on the transfer of electricity between regions is called 'inter-regional congestion'.

3.2.2 The dispatch process and constraint equations

To understand how the transmission system is managed in the NEM and how inter-regional congestion may occur, it is useful to describe how transmission limits are managed in the NEM's dispatch optimisation.

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.

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. These include generator offers, and also the thermal, voltage and stability limits of the network. Within these parameters, NEMDE calculates the optimal market solution for dispatch, i.e. the lowest cost solution for dispatch of generation in order to meet demand, allowing for any constraints that may occur on the transmission network.

Limitations affecting the network's ability to carry electricity 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 allowable flows across particular transmission lines. A network constraint is thus a limitation that AEMO imposes on the market dispatch process to account for the physical restrictions necessary for the secure operation of the system.[39]

Terms which occur in constraint equations represent physical attributes such as output from generators, thermal limits of transmission lines, electricity demand in various locations, flows in the network and availability of reactor and capacitor banks. Each constraint equation or set of constraint equations represents a particular type of power system limitation or requirement. Constraint equations can also exist for specific configurations of the power system such as system normal or plant outages.[40]

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'.

BOX 2: USE OF CONSTRAINT EQUATIONS BY GENERATORS

In regards to the use of constraint equations by market participants, AEMO highlights that constraint equation formulation is important to scheduled entities such as generators and dispatchable loads because constraint formulation determines the influence or variation in output from that which might be expected from a consideration of offer prices alone.

A generator can be bound by a constraint equation to provide a higher output than it normally would on a commercial basis (called being 'constrained on'). Conversely, a generator may be required to reduce its output due to the action of a constraint equation. If a generator is thus 'constrained off' it may result in a generator selling a lower level of output than they would have otherwise sold.

Source: AEMO, *Constraint Formulation Guidelines,* December 2013, p. 6.

3.2.3 Inter-regional constraints

In simple terms, inter-regional constraints are a sub-set of constraints; they are constraints that can affect the flows between two (or more) regional reference nodes.[41] As discussed previously, interconnector flows are not solely influenced by a few constraints associated with 'pinch points' on interconnectors at regional boundaries. They are a function of numerous limitations across the majority of the physical network. Hence an inter-regional constraint

39 AEMO puts it this way: "AEMO determines generation schedules and regional prices in the National Electricity Market using a solver which finds the optimal solution to maximise the value of trade. The solution must satisfy linear constraint equations which are crafted to represent the physical restrictions necessary for secure and sustainable operation." AEMO, *Constraint Formulation Guidelines*, 5 December 2013, p. 6.

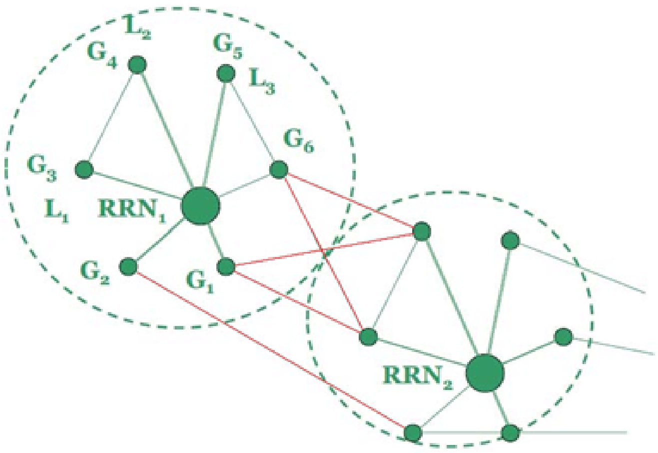
40 For further information see AEMO, *Constraint Implementation Guidelines for the National Electricity Market*, June 2015.

41 Regional reference notes are located at the largest load centre of each region and are used to calculate spot market prices. See Figure 3.4 for the locations of the NEM's regional reference nodes.

may be a constraint associated with transmission network infrastructure far from an interconnector.

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 3.5. 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. In terms of NEMDE, an inter-regional constraint is a constraint that contains an inter-connector term in the constraint equation.[42]

Figure 3.5: Stylised representation of interconnectors as cross-border infrastructure and additional transmission infrastructure to carry flows to regional reference nodes



Source: AEMO, *Electricity network regulation – AEMO's response to the Productivity Commission issues paper*, 21 May 2012, p. 30 (adapted).

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.

The NER specifies that before it can exercise the LRPP, the AEMC must "identify a problem relating to constraints in respect of national transmission flow paths *between regional reference nodes* or a potential transmission project".[43] Hence, to conduct the LRRP assessment the Commission examines AEMO's forecasts of those constraints likely to impact the flow of electricity between two regional reference nodes.

42 A generic constraint is classified as an inter-regional constraint if it includes an interconnector flow term in the constraint's left hand side (LHS). That is, the constraint has a non-zero coefficient for one or more interconnector flow terms in its left hand side.

43 Rule 5.22(g) of the NER, emphasis added. National transmission flow paths are "[t]hat portion of a transmission network or transmission networks used to transport significant amounts of electricity between generation centres and load centres."

3.2.4 Constraint equations as indicators of congestion

Congestion in the network may be identified by observing which constraint equations are binding.[44] Inter-regional congestion can be examined by considering which inter-regional constraints are currently binding, or are expected to bind in the future.

At present there are approximately 11,000 constraint equations used to manage generation and electricity management in the NEM.[45] Approximately 70 per cent of constraints across the transmission network are inter-regional constraints (2014).[46]

Information about constraints is a key input into the planning process for the transmission network. Network service providers 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'.[47] This could include upgrading transmission lines to increase their capacity or installing a new transformer so more power can flow through existing lines.
- Solutions such as demand-side management and network support control ancillary services, which may reduce the strain on transmission infrastructure elements during certain periods, thereby assisting in maintaining operation of this infrastructure within its physical limits.[48] These solutions are termed 'non-network options'.

3.2.5 Recent inter-regional congestion

The Commission has analysed the 'system normal' constraints that had the largest marginal financial cost by binding on interconnector limits.[49] Table 3.2 presents the top 10 binding constraints affecting inter-regional transfers in the NEM based on their 2017 market impact. The market impact value seeks to quantify, in dollar value, the relative impact of a particular constraint (see box 3).[50] The 2016 market impacts of these constraints are also shown for comparative purposes.

44 A constraint equation is binding when the power system flow it manages reach applicable thermal or stability limits, or when a constraint equation is setting an FCAS requirement. When a constraint equation is binding, NEMDE changes the generator and interconnector targets to satisfy the constraint equation. See AEMO, *NEM Constraint Report 2016*, June 2017, p. 12.

45 AEMO, *NEM Constraint Report 2016*, June 2017, p. 6. Excluded from these totals are any constraint sets, equations or functions archived before December 2016, and any created by the outage ramping process.

46 AEMC 2015, *Optional Firm Access, Design and Testing*, Final Report - Volume 1, 9 July 2015, p. 71. See also Intelligent Energy Systems, *Assessment of Inter-Regional Congestion*, November 2011, p. 18 (excludes FCAS constraints), when the percentage was approximately 67 per cent. While the number and type of constraint equations has changed since 2014, the proportion remains a valid indication of the interrelated nature of the transmission network.

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

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

49 System normal constraints do not include constraints caused by outages of transmission elements. The table does not include constraints involving frequency control ancillary service (FCAS) requirements.

50 The market impact is calculated by adding up the marginal values from the marginal constraint cost re-run and dividing by 12. 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.

> ### BOX 3: THE MEANING OF THE 'MARKET IMPACT' OF A CONSTRAINT AND HOW IT IS CALCULATED
>
> Every dispatch interval, NEMDE provides the marginal value of every constraint used in the dispatch process. The marginal value of a constraint is the effect on total dispatch costs of alleviating that constraint by 1 MW. This is a measure of the *congestion cost* arising from the constraint in a given dispatch interval.
>
> Summing the marginal values of a constraint over some time period (e.g. a year) gives a measure of that constraint's congestion cost over that time period. We call this the *market impact* of the constraint.
>
> It is important to remember that the market impact measures the *marginal cost* of a constraint, and not the total cost. For example, in a given dispatch interval the marginal value of a constraint might be $10,000 per MWh. This does not mean that alleviating the constraint by 10 MW will yield a benefit of $100,000/h – the marginal cost may fall rapidly as the constraint is alleviated, and may even fall to zero, which means the constraint is no longer binding.

Further, given the interconnectedness of the transmission system, sometimes a constraint may contain multiple interconnector terms. 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 VNI interconnectors.[51] Additionally, AEMO only provides a single total market impact figure for each constraint.[52] Hence, when a single inter-regional constraint impacted multiple interconnectors, AEMO only calculates one market impact. In Table 3.2, each single constraint calculation is listed for each of the interconnectors on which it impacts.

The table shows that:

- The market impact of seven out of the top 10 inter-regional constraints has increased, and the market impact of the other three constraints has decreased.
- There were a number of constraints which bound more than one interconnector between Victoria and several other states.
- The major constraints which bound the interconnectors between New South Wales and Queensland were the only inter-regional constraints that did not also bind any interconnectors between other states in the NEM.
- The Murraylink interconnector and VNI were the interconnectors that were most affected by the top 10 most significant inter-regional constraints, as each was bound by five out of the 10 constraints.

51 For more details, see constraints #1, #2, #4, #7, #8 and #10 in Table 3.2.

52 AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

- The Basslink interconnector was the interconnector that was least affected by the top 10 most significant inter-regional constraints, as it was only bound by two of the top 10 constraints.
- Five of the top ten constraints bound for more hours in 2017 than in 2016, while the other five bound less in 2017 than in 2016.

Table 3.2: **Top 10 inter-regional system normal constraints in the NEM based on 2017 market impact**

2017 NEM MARKET IMPACT RANKING AND AEMO EQUATION ID[1]	MARKET IMPACT ($2017)		DESCRIPTION	HOURS BINDING		FLOW DIRECTION
	2017	2016		2017	2016	
1a N>>N-NIL__3_OPENED	801,599	295,872	This is a thermal overload constraint. Thermal overload constraints are used to manage the power flow on a transmission element so that it does not exceed a rating (either continuous or short term) under normal conditions or following a credible contingency. This constraint is used to avoid overloading the Liddell, NSW to Muswellbrook, NSW 330 kV line in the case of a trip of the Liddell, NSW to Tamworth, NSW 330 kV line.	21	60	QNI NSW export
1b N>>N-NIL__3_OPENED				2	40	Terranora NSW export
2a N^^V_NIL_1	736,588	43,476	This constraint manages voltage stability, which is used for managing transmission voltages so that they remain at acceptable levels if a credible contingency occurs. The relevant contingency event is the loss of the largest Victorian generating unit or the Basslink interconnector.	1,806	82	VNI NSW export
2b N^^V_NIL_1				1,343	69	Murraylink Victoria export
3 V:S_600_HY_T	582,677	78,448	The constraint is used as the upper limit for the Heywood interconnector to manage oscillatory	98	76	Heywood Victoria export

2017 NEM MARKET IMPACT RANKING AND AEMO EQUATION ID[1]	MARKET IMPACT ($2017)		DESCRIPTION	HOURS BINDING		FLOW DIRECTION
	2017	2016		2017	2016	
EST_DYN			stability. It limits network flows to ensure the dampening of power system oscillations is adequate following a credible contingency.			
4a N^^Q_NIL_B1, 2, 3, 4, 5, 6 & N^Q_NIL_B	556,068	478,327	This constraint is used to manage voltage stability, which is used for managing transmission voltages so that they remain at acceptable levels after a credible contingency instead of collapsing. The relevant contingency event is the loss of the largest Queensland generating unit.	148	572	QNI NSW export
4b N^^Q_NIL_B1, 2, 3, 4, 5, 6 & N^Q_NIL_B				78	340	Terranora NSW export
5 V^SML_NSWRB_2	441,280	531,291	This constraint is used to manage voltage stability in the case of an electricity supply interruption of a 220 kV line from Darlington Point, NSW to Buronga, NSW, when the Murraylink runback scheme is enabled.	53	154	Murraylink Victoria export
6 N>>N-NIL__B_15M	237,706	2,493	This thermal overload constraint is used to avoid overloading the Upper Tumut to Canberra line in NSW and the ACT in the case of a trip of the Lower Tumut to Canberra line.	4	0.2	VNI Victoria export

2017 NEM MARKET IMPACT RANKING AND AEMO EQUATION ID[1]	MARKET IMPACT ($2017)		DESCRIPTION	HOURS BINDING		FLOW DIRECTION
	2017	2016		2017	2016	
7a V>>SML_NIL_8	185,107	82	This is a thermal overload constraint. Thermal overload constraints are used to manage the power flow on a transmission element so that it does not exceed a rating (either continuous or short term) under normal conditions or following a credible contingency. This constraint is used to avoid exceeding the rating of the Ballarat, Victoria to Bendigo, Victoria 220 kV line in the case of an interruption of supply through the Shepparton, Victoria to Bendigo, Victoria 220 kV line.	2	0.3	Murraylink Victoria export
7b V>>SML_NIL_8				2	0.3	VNI Victoria export
8a V::N_NILxxx	181,973	244,494	This constraint is used to maintain transient stability of the Yallourn Power Station in the case of a fault on one of the 500 kV lines from Heywood in Victoria to South East in South Australia.	581	942	VNI Victoria export
8b V::N_NILxxx				560	808	Murraylink Victoria export
8c V::N_NILxxx				279	619	Basslink Victoria export
8d V::N_NILxxx				453	575	Heywood Victoria export

2017 NEM MARKET IMPACT RANKING AND AEMO EQUATION ID[1]	MARKET IMPACT ($2017)		DESCRIPTION	HOURS BINDING		FLOW DIRECTION
	2017	2016		2017	2016	
9 Q:N_NIL_AR_2L-G & Q::N_NIL_AR_2L-G	151,611	0	This constraint is used to maintain transient stability for a double line-to-ground (2L-G) fault at Armidale, NSW.	516	0	QNI NSW import
10a V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P	143,897	147,950	This is a thermal overload constraint used to avoid overloading the South Morang 500/330 kV (F2) transformer when there are no contingencies and radial/parallel modes occur involving Yallourn W1 and the 500 or 220 kV lines that the generator is connected to.	288	814	Basslink Victoria import
10b V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P				286	957	VNI Victoria export
10c				294	945	Heywood

2017 NEM MARKET IMPACT RANKING AND AEMO EQUATION ID[1]	MARKET IMPACT ($2017)		DESCRIPTION	HOURS BINDING		FLOW DIRECTION
	2017	2016		2017	2016	
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P						Victoria import
10d V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P				272	879	Murraylink Victoria export

Source: AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

Note: 1 - System normal constraints do not include constraints caused by outages of transmission elements. The table does not include constraints involving FCAS requirements.

BOX 4: CONGESTION AND INTER-REGIONAL SETTLEMENT RESIDUES

Participants in the NEM who engage in inter-regional trade are exposed to the risk of divergence between regional reference prices in the NEM. This occurs because generators receive the spot price in the region where they operate, while retailers pay the spot price in the region where 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, adjusted for losses. 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.

Source: AEMO, *Guide to the settlements residue auction*, August 2018, pp. 6-7.

Note: For further detail see AEMC 2017, *Secondary trading of settlement residue distribution units*, Rule Determination, 10 October 2017. See also AEMC, *Last resort planning power - 2017 review*, Decision report, 7 November 2017, pp. 22-23.

4 PLANNING REPORTS CONSIDERED BY THE COMMISSION

This chapter outlines the planning reports and related documents that the Commission has examined in undertaking the LRPP 2018 review.

4.1 The NTNDP and the ISP

The NTNDP is an annual report published by AEMO as part of its role as the national transmission planner.[53] The NER requires the AEMC to take the NTNDP for the current and previous year into account in deciding whether or not to exercise the LRPP.[54] In addition, the guidelines state that the AEMC has an obligation to use the two most recent NTNDPs.[55]

The relevant NTNDPs for the 2018 LRPP are AEMO's 2016 NTNDP (published in December 2016) and the 2018 ISP (published in July 2018), which the Commission is taking to serve as the current 2017 NTNDP for the purposes of this review.

The ISP includes three types of proposed projects which vary based on the timing of the need, the project scale and the time required to construct the project:[56]

- Group 1 projects require immediate investment in transmission to be undertaken, with completion as soon as practicable
- Group 2 projects require action to be taken now, to initiate work on projects for implementation by the mid-2020s
- Group 3 projects involve enhancing the capability of the grid in the longer term, to the mid-2030s and beyond.

Many of these projects are proposed in order to address constraints that restrict inter-regional flows, and are therefore discussed within this report.

As outlined in section 2.3, on 21 December 2018 AEMO published a 2018 NTNDP. This document updated some of the information contained in the 2018 ISP. The 2018 NTNDP outlines the current status of major proposed transmission infrastructure, such as QNI interconnector upgrades. The current status of many of these network proposals are detailed in this LRPP report, as well as the inter-regional constraints that AEMO identified in the 2018 NTNDP.

TNSPs are required to address the issues raised in the 2018 NTNDP in their 2019 TAPRs, published by 30 June 2019. After TNSPs have published their 2019 TAPRs, the Commission will assess, as part of the 2109 LRPP review, whether TNSPs are addressing the inter-regional constraints identified by AEMO in the 2018 NTNDP.[57]

53 Rule 5.20(2) of the NER.

54 Rule 5.22(f)(2) of the NER.

55 AEMC, *Last Resort Planning Power Guidelines*, September 2015, p. 2.

56 AEMO, *Integrated System Plan*, July 2018, pp. 8-10; p. 80.

57 AEMO, *National Transmission Network Development Plan*, December 2018, p. 28. The Commission will also consider ElectraNet's SA Energy Transformation RIT-T project assessment conclusions report, published 13 February 2019, in the 2019 LRPP review.

4.2 Congestion information resource

The LRPP guidelines require the Commission to consider the most recent congestion information resource published by AEMO in assessing whether to exercise the LRPP.[58] The guidelines state that the Commission must use the most recent congestion resource as a major component in its analysis to determine whether there are any inter regional flow constraints in the national electricity market that may not have been examined by TNSPs.[59]

The Commission has considered the National Electricity Market Constraint Report 2017 Electronic Material in conducting this 2018 LRPP assessment.[60]

4.3 Annual planning reports

Each TNSP must publish an annual planning report (APR) by 30 June each year.[61] The APR sets out the outcomes of the annual planning review which a TNSP is required to conduct under the NER.[62] 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.[63] In addition, a TNSP must consider the potential for network augmentations or non-network alternatives to augmentations when conducting an annual planning review.[64] The minimum forward planning period for the annual planning review and therefore covered by the annual planning report is ten years.

These APRs are commonly referred to as 'TAPRs'. AEMO as the Victorian transmission network planner under the NEL publishes a Victorian annual planning report (VAPR), which fulfils the same function as the TAPR for the Victorian transmission network.[65]

TNSPs must take the most recent NTNDP into account when conducting their annual planning review.[66] In particular, when a TNSP proposes augmentations to the network, it must explain in its annual planning report how the proposed transmission augmentations relate to the most recent NTNDP and the development strategies for current or potential national transmission flow paths specified in the NTNDP.

This obligation aligns the planning priorities identified by AEMO in the NTNDP regarding inter-regional flow paths and the planning activities undertaken by TNSPs for each jurisdiction.

As required by the NER and the guidelines, the Commission must consider these annual planning reports when contemplating whether to exercise the LRPP. The NER requires the AEMC to take the TAPRs for the current year into account in deciding whether or not to

58 AEMC, *Last Resort Planning Power Guidelines*, 24 September 2015, p. 2.
59 ibid, p. 2.
60 AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.
61 Clause 5.12.2(a) of the NER.
62 Clause 5.12.1(b) of the NER.
63 Clause 5.12.1(a) of the NER.
64 Clause 5.12.1(b)(4) of the NER.
65 Clause 5.12.1 of the NER. See also AEMO, *Victorian Annual Planning Report*, July 2018, p. 8.
66 Clause 5.12.1(b)(3) of the NER.

exercise the LRPP.[67] Correspondingly, the guidelines state that the AEMC has an obligation to use the most recent TAPRs as a major component in its analysis.[68]

The Commission has analysed the following TAPRs in undertaking this 2018 LRPP review:

- The 2018 Victorian Annual Planning Report published by AEMO.
- The 2018 South Australian Transmission Annual Planning Report published by ElectraNet.
- The Transmission Annual Report 2018 published by Powerlink.
- The Annual Planning Report 2018 published by TasNetworks.
- The 2018 New South Wales Transmission Annual Planning Report published by TransGrid.

4.4 The RIT-T

4.4.1 RIT-Ts

The NER requires that TNSPs must apply a RIT-T for any projects with an estimated cost of more than $6 million.[69] This requirement covers both augmentation and replacement expenditure.[70]

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 electricity in the market, after performing a cost-benefit analysis on a number of credible options. 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.

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.

The NER also require the RIT-T 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 plants
  - differences in capital costs
  - differences in operating and maintenance costs
- changes in network losses

67 Rule 5.22(f)(2) of the NER.

68 AEMC, *Last Resort Planning Power Guidelines*, 24 September 2015, p. 2.

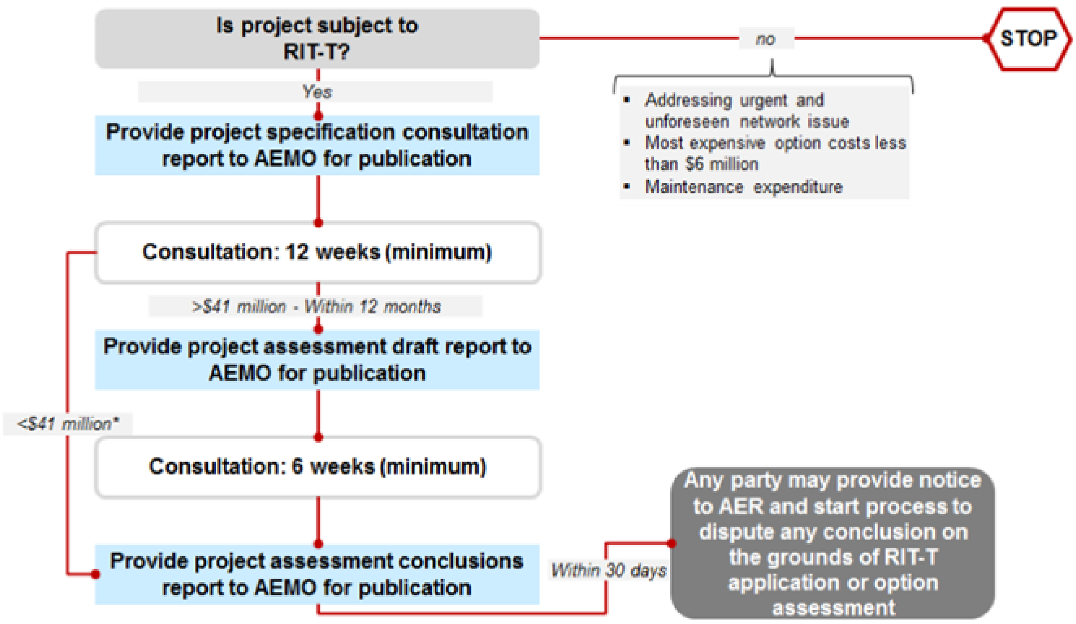
69 The application of the RIT-T is also subject to a number of exceptions under clause 5.16.3(a) of the NER. The threshold increased to $6 million on 1 January 2016 as a result of a cost thresholds review final determination made by the AER on 5 November 2015.

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

- changes in ancillary service costs
- competition benefits.[71]

The procedure that a proponent must follow in conducting a RIT-T is also outlined in the NER. The AER has also developed the RIT-T application guidelines on the operation and application of the RIT-T. The major steps in the RIT-T process are outlined in Figure 4.1.

Figure 4.1: Overview of the RIT-T consultation process



Source: AEMC, *National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, Rule Determination,July 2017, p. 65.

Note: * If the estimated capital cost of the investment option falls below $41 million, a RIT-T proponent can skip the project assessment draft report consultation step. In January 2019, this threshold increased to $43 million. For more information, see AER, *Final determination - Cost thresholds review*, November 2018.

Note: For a more exhaustive list of the circumstances where a TNSP does not need to apply the RIT-T, see AER, *Regulatory investment test for transmission application guidelines,* September 2017, pp. 4-5.

4.4.2 LRPP obligations on the AEMC and RIT-Ts considered

The guidelines require the AEMC to consider any relevant RIT-T reports when investigating the possible need to utilise the LRPP.[72] In conducting the 2018 LRPP review, the Commission has examined several RIT-T reports including:

- The South Australia Energy Transformation project assessment draft report (PADR), published by ElectraNet in June 2018.[73]

71 Clause 5.16.1(c)(4) of the NER.

72 AEMC, *Last Resort Planning Power Guidelines*, 24 September 2015, p. 2.

73 ElectraNet, *SA Energy Transformation RIT-T Project Assessment Draft Report,* June 2018.

- The Project Marinus project specification consultation report (PSCR), published by TasNetworks in July 2018.[74]
- The Expanding NSW-QLD transmission transfer capability PSCR, published by Powerlink and TransGrid in November 2018.[75]
- The Victorian to New South Wales interconnector upgrade PSCR, which was published by AEMO and TransGrid in November 2018.[76]

4.4.3 Other relevant documents

TNSPs use a Network Capability Incentive Action Plan (NCIPAP) to obtain approval from the AER for certainlow cost projects addressing transmission network constraints. Relevant transmission projects addressing inter-regional constraints that are completed via the NCIPAP process rather than the RIT-T process have also been considered by the Commission.

The NCIPAP is part of the AER's Service Target Performance Incentive Scheme and provides financial incentives for TNSPs to undertake low cost one-off operational and capital expenditure projects that have broader market benefits. Eligible and completed projects of up to a total of one percent of the proposed maximum allowed revenue for the TNSP per year will receive a pro-rata incentive payment of up to 1.5 per cent of the maximum allowed revenue.[77] During the development of the NCIPAP, the TNSP collaborates with AEMO to identify options and quantify the market benefits of potential NCIPAP projects. TNSPs must then submit their NCIPAP to the AER as a part of their revenue proposals. If the projects are approved by the AER, the TNSP can receive additional revenue for them as part of their upcoming TNSP regulatory period.

74 TasNetworks, *Project Marinus Project Specification Consultation Report - Additional interconnection between Victoria and Tasmania*, July 2018.

75 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018.

76 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018.

77 For further details, see AER, *Final Decision - Electricity transmission network service providers service target performance incentive scheme*, September 2015, p. 7.

5 REVIEW OF QUEENSLAND - NEW SOUTH WALES CONGESTION

> **BOX 5: SUMMARY OF FINDINGS**
>
> All transmission network inter-regional constraints expected to affect flows between Queensland and New South Wales are being addressed by the relevant TNSPs in their transmission annual planning reports. This includes all inter-regional constraints relevant to the Queensland – New South Wales (QNI) interconnector and those relevant to the Terranora interconnector. 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 chapter provides the Commission's analysis of whether there are any significant inter-regional constraints affecting the flows between Queensland and New South Wales that are not being addressed by the relevant TNSPs. The chapter:

- Describes QNI and the Terranora interconnector.
- Reviews inter-regional constraints between Queensland and New South Wales by examining:
  - The constraints expected to affect these interconnectors into the future based on an examination of AEMO's 2018 ISP, the 2016 NTNDP and additional written advice provided by AEMO to the AEMC.
  - The binding constraint equations that had the highest market impact in 2017 (from AEMO's 2018 NEM constraint data).
- Reviews Powerlink and TransGrid's 2018 TAPRs and the Expanding NSW-QLD transmission transfer capacity PSCR regarding projects that address inter-regional constraints affecting QNI and the Terranora interconnector.[78]
- Compares the proposed projects that Powerlink and TransGrid identify in these reports with AEMO's expected inter-regional constraints to identify if there are any 'gaps' where a TNSP has not responded to an expected inter-regional constraint identified by AEMO.

5.1 Introduction

5.1.1 Historical flows between Queensland and New South Wales

Figure 5.1 presents the annual flows of electricity between Queensland and New South Wales over the last ten financial years.[79] The negative flows indicate flows from Queensland to New

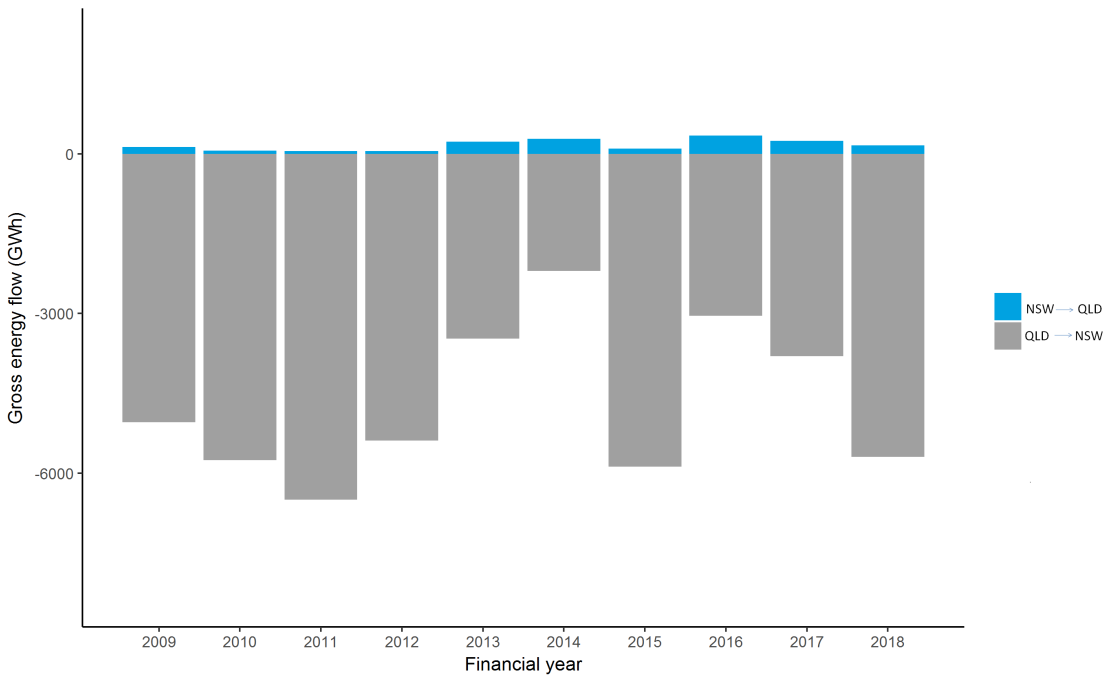
78 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018.

79 This chart includes all constraints binding QNI and the Terranora interconnector, including any system normal or outage constraints. The financial year as reported in the chart encompasses the first half of that year and the second half of the previous year; i.e. 2018 represents the 2017/18 financial year.

South Wales and the positive flows indicate flows from New South Wales to Queensland. The chart shows:

- Flows have predominately been from Queensland to New South Wales.
- Flows from Queensland to New South Wales have progressively increased over the past three financial years, while flows from New South Wales to Queensland have decreased over the same period.

Figure 5.1: Inter-regional flows between Queensland and NSW (2009 - 2018)



Two interconnectors transport electricity in the NEM between Queensland and New South Wales; QNI and the Terranora interconnector.

5.1.2 The Queensland - New South Wales interconnector (QNI)

QNI is a 330 kV alternating current double circuit interconnection that runs between Bulli Creek in Queensland and Dumaresq in New South Wales.[80]

QNI currently has a nominal capacity of:[81]

- 300 - 600 MW from New South Wales to Queensland, due to voltage collapse.[82]

80 AEMO, *Interconnector Capabilities*, November 2017, p. 4.

81 ibid, pp. 4-5.

82 ibid. Transfers in this direction are limited to between 200 and 400 MW when Kogan Creek is in service and can reach up to 600 MW with Kogan Creek out of service and other large Queensland generators at lower output.

- 1050 - 1078 MW from Queensland to New South Wales, mainly due to transient stability limits. When Phasorpoint equipment is in service, it can help manage oscillatory stability and the associated limit is 1200 MW.

In terms of recent flows on QNI, Figure 5.2 shows all flows during the 2016-2017 financial year and Figure 5.3 shows all flows during the 2017-2018 financial year.[83] Flows from New South Wales to Queensland are shown as positive, and flows from Queensland to New South Wales appear as negative.

The chart also shows (in purple) when inter-regional constraints have limited the flows on the interconnector below its maximum capacity in each direction (i.e. constraints have 'bound').[84] While bound constraints are generally bound below a certain 'maximum' level, sometimes constraints can be bound to prevent the flows from falling below a 'minimum' level.

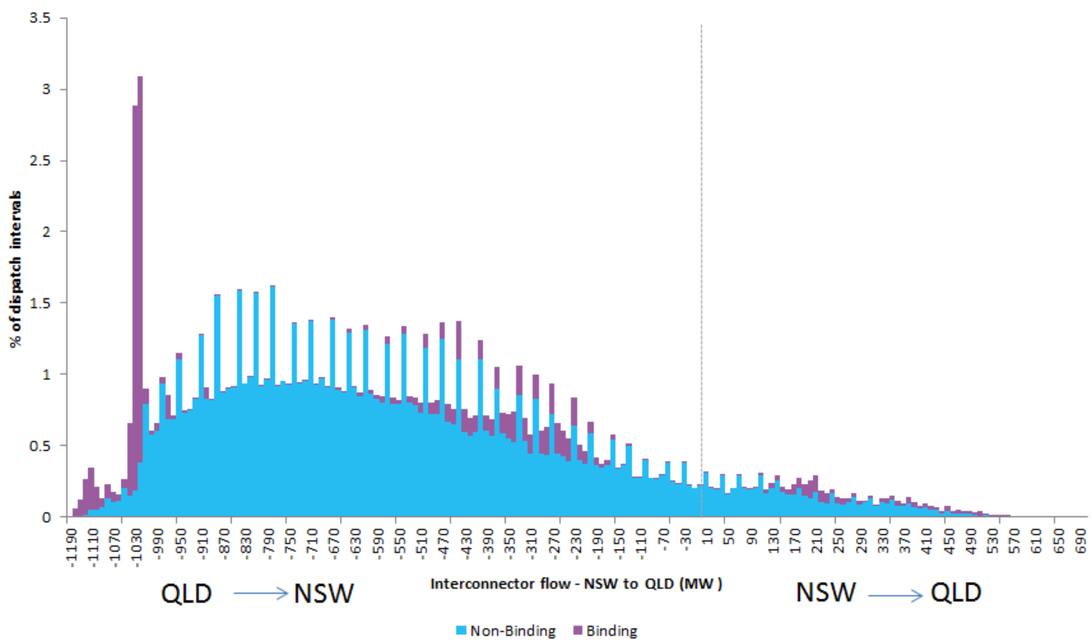
Figure 5.2: Inter-regional flows via QNI (2016-2017)

Source: AEMC analysis of Neopoint database.
Note: This figure covers financial years.

83 These charts include all constraints binding QNI, including any system normal or outage constraints.

84 A constraint is said to be 'binding' when AEMO cannot dispatch the lowest bid priced generation because of network constraints. A constraint is said to be an inter-regional constraint if it impacts on flows between NEM regions. That is, if the constraint limits flows on an interconnector (See Chapter 3, section 3.2.2).

Figure 5.3: Inter-regional flows via QNI (2017 - 2018)



Source: AEMC analysis of Neopoint database.
Note: This figure covers financial years.

These charts indicate a trend of increasing flows from Queensland to New South Wales, and flows from New South Wales to Queensland at higher flow rates through QNI. The charts show that flows from New South Wales to Queensland above approximately 330 MW were more frequent in 2017-18 than in 2016-17; however, flows in the same direction below 330 MW were less frequent in 2017-18 than in 2016-17. In regard to flows from Queensland to New South Wales, flows with rates higher than 150 MW were more frequent in 2017-18 than in 2016-2017, while flows below 150 MW were less frequent in 2017-18 than in 2016-2017.

Regarding constraints on the interconnectors, New South Wales imports via QNI generally bound more often at higher flow levels in 2017-18 than in 2016-17, and also bound more frequently near the nominal capacity limit of 1078 MW. However, New South Wales imports at times during 2017-2018 also exceeded the 1078 MW nominal limit that can be imposed in this direction (whereas flows in this direction always stayed below that nominal limit in 2016-17). While in 2016-17 New South Wales imports frequently bound below 300 MW, in 2017-18 they bound much less frequently in this direction and periodically flowed at levels higher than 300 MW but below 600 MW.

5.1.3 The Terranora interconnector

The Terranora interconnector comprises the two 110 kV lines from Terranora in New South Wales to Mudgeeraba in Queensland.[85] The controllable element of the interconnector is a 180 MW direct current link between Terranora and Mullumbimby (both in New South Wales), known as Directlink.[86]

Directlink consists of three separate bipolar current underground cables with a capacity of 60 MW each.[87] While geographically located in NSW, Directlink effectively delivers electricity between New South Wales and Queensland due to its position in the transmission network.[88] Due to the local load connected around Terranora, the nominal capacity for Terranora differs from that of Directlink.[89]

Terranora currently has a nominal capacity of:

- 107 MW from New South Wales to Queensland
- 210 MW from Queensland to New South Wales.[90]

Figure 5.4 shows all flows in both directions on the Terranora interconnector during the 2016-2017 financial year and Figure 5.5 shows all flows in both directions on the Terranora interconnector during the 2017-2018 financial year.[91] Flows from New South Wales to Queensland are shown as positive while those from Queensland to New South Wales appear as negative.The chart also shows (in purple) when inter-regional constraints have limited the flows on the interconnector below its maximum capacity in each direction (i.e. constraints have ‘bound’).

85 AEMO, *Interconnector Capabilities*, November 2017, p. 4.

86 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.

87 AEMO, *Interconnector Capabilities*, November 2017, p. 4.

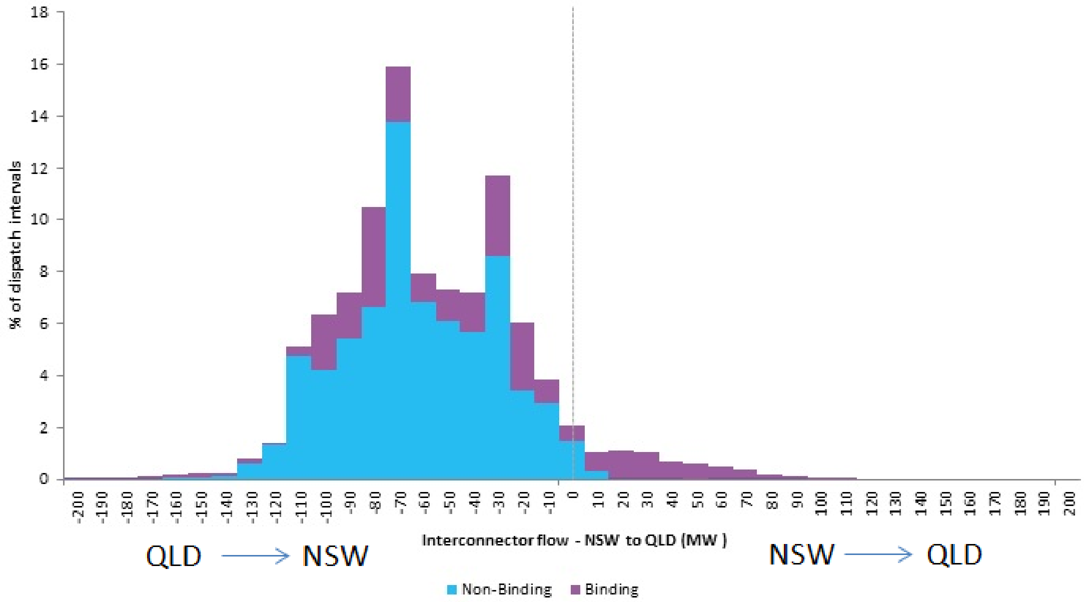
88 APA Group, Electricity Interconnectors, viewed 10 September 2018, https://www.apa.com.au/our-services/other-energy-services/electricity-transmission-interconnectors.

89 ibid.

90 AEMO, *Interconnector Capabilities*, November 2017, p. 4.

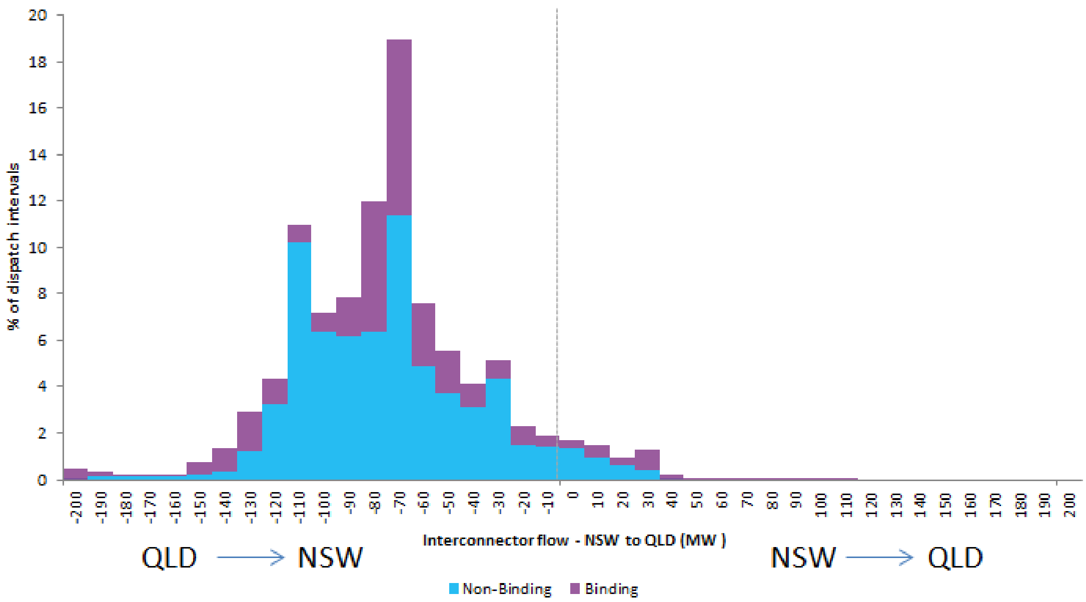
91 These charts include all constraints binding the Terranora interconnector, including any system normal or outage constraints.

Figure 5.4: Inter-regional flows via the Terranora interconnector (2016 - 2017)



Source: AEMC analysis of Neopoint database.
Note: This figure covers financial years.

Figure 5.5: Inter-regional flows via the Terranora interconnector (2017 - 2018)



Source: AEMC analysis of Neopoint database.
Note: This figure covers financial years.

These charts indicate a slight trend of increasing flows from Queensland to New South Wales and decreasing flows from New South Wales to Queensland through the Terranora interconnector. They show that transfers from Queensland to New South Wales on the Terranora interconnector occurred at higher flow rates in 2017-18 than the previous year. Flows above 90 MW were more frequent in 2017-18 than in 2016-2017, while flows below 90 MW were less frequent in 2017-18 than in 2016-2017. Transfers from NSW to Queensland generally increased in 2017-18 compared with 2016-17, as well as at higher flow rates.

In terms of constraints, the charts show that energy flows from New South Wales to Queensland on the Terranora interconnector bound less frequently in 2017-18 than during the previous year. In regard to energy flows from Queensland to New South Wales, the Terranora interconnector bound much more frequently at the 70 MW rate in 2017-18 than during the previous year.

5.2 Current inter-regional constraints affecting Queensland – New South Wales flows

This section outlines several major binding inter-regional constraints that currently affect Queensland – New South Wales flows (in both directions) related to either QNI or the Terranora interconnector. It examines binding constraints in terms of their total market impact, with a focus on system normal constraints.[92] The information and analysis in this section is based on AEMO data on constraint equation performance for the 2017 calendar year.[93]

In 2017, the total market impact of inter-regional system normal constraints was higher for electricity flows from New South Wales to Queensland than for flows in the other direction.[94] The total market impact of inter-regional system normal constraints was higher in both directions in 2017 than during the previous year.[95]

Three of the top ten (by total market impact) inter-regional binding system normal constraints for all the interconnectors in the NEM are associated with flows between Queensland and New South Wales.[96] The highest impact constraint by market value in the NEM in 2017 was associated with flows between Queensland and NSW ($801,599). Table 5.1 shows that:

- Two of the top three constraints which affected Queensland – New South Wales flows bound both QNI and the Terranora interconnectors. (The two constraints are shown as constraint #1a and #1b, and constraint #4a and #4b.)
- While these two constraints bound both interconnectors for fewer hours in 2017 than in 2016, the market impact in 2017 was higher than in 2016 ($1,357,667 in 2017 compared to $774,199 in 2016).
- For the two constraints which bound for both interconnectors, QNI was bound for a larger number of hours than the Terranora interconnector. This applied in 2016 and in 2017.
- The two constraints which bound for both interconnectors involved flows from New South Wales to Queensland. The single constraint which bound QNI without binding the Terranora interconnector involved flows from Queensland to New South Wales.

92 See Chapter 3, section 3.2.5 for an explanation of 'market impact' and how it is calculated. System normal constraints do not include constraints caused by outages of transmission elements.

93 AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

94 Analysis based on figures from AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

95 ibid.

96 The top ten constraints are listed in Chapter 3, section 3.2.5, Table 3.2. Additional detail regarding the listed constraints is also located in AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

Table 5.1: **Current major inter-regional system normal constraints affecting Queensland - NSW**

2017 NEM MARKET IMPACT RANKING AND AEMO EQUATION ID[1]	MARKET IMPACT[2] ($2017)		DESCRIPTION[3]	HOURS BINDING		FLOW DIRECTION
	2017	2016		2017	2016	
1a N>>N-NIL__3_OPENED Thermal overload	801,599	295,872	This is a thermal overload constraint. Thermal overload constraints are used to manage the power flow on a transmission element so that it does not exceed a rating (either continuous or short term) under normal conditions or following a credible contingency. This constraint is used to avoid overloading the Liddell, NSW to Muswellbrook, NSW 330 kV line in the case of a trip of the Liddell, NSW to Tamworth, NSW 330 kV line.	21	60	QNI NSW export
1b As above				2	40	Terranora NSW export
4a N^^Q_NIL_B1, 2, 3, 4, 5, 6 & N^Q_NIL_B Voltage stability	556,068	478,327	This constraint is used to manage voltage stability, which is used for managing transmission voltages so that they remain at acceptable levels after a credible contingency instead of collapsing. The relevant contingency event is the loss of the largest Queensland generating unit.	148	572	QNI NSW export
4b As above				78	340	Terranora NSW export
9 Q:N_NIL_AR_2L-G & Q::N_NIL_AR_2L-G Transient stability	151,611	0	This constraint is used to maintain transient stability for a double line-to-ground (2L-G) fault at Armidale, NSW.	516	0	QNI NSW import

Note: 1 - System normal constraints do not include constraints caused by outages of transmission elements. The table does not include constraints involving FCAS requirements. This table uses calendar years, and the constraints are categorised by market impact. The inter-regional constraints in this table are the constraints relevant to this chapter from the top 10 inter-regional constraints by total market impact for the entire NEM (2017) presented in Table 3.2.

Note: 2 - 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 over a year to provide a total marginal market impact. A 2.5 per cent inflation rate is assumed for 2016 values.

Note: 3 - Additional details regarding the listed constraints are located in AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

5.3 Expected inter-regional constraints and TNSP proposed projects

5.3.1 Sources considered

This section examines whether all expected inter-regional constraints affecting flows between Queensland and New South Wales are being adequately addressed by the relevant TNSP. It presents the inter-regional constraints that AEMO in its national transmission planning role expects are likely to affect flows between Queensland and New South Wales into the future. The sources included in the analysis are AEMO's 2016 NTNDP, the 2018 ISP and the additional written advice AEMO has provided to the AEMC.

The section then identifies projects that TransGrid and Powerlink propose in their 2018 annual planning reports to address these expected inter-regional constraints, as well as the projects proposed in TransGrid and Powerlink's PSCR Expanding NSW-QLD transmission transfer capacity, which was published in November 2018.

It then compares the projects that TransGrid and Powerlink identify in their annual planning reports with AEMO's expected inter-regional constraints, to identify if there are any 'gaps' where a TNSP has not responded to the expected inter-regional constraint identified by AEMO.[97]

The Commission's analysis for QNI is presented first, followed by analysis of the Terranora interconnector.

5.3.2 Findings: Queensland – New South Wales interconnector (QNI)

AEMO has identified three expected inter-regional constraints on QNI. All three constraints were identified by AEMO in its written advice provided to the AEMC. AEMO clarified that these constraints correspond with augmentation drivers described in the 2018 ISP and transmission limitations identified in the 2016 NTNDP.[98]

One of these expected constraints—which in 2017 had the highest market impact of any inter-regional constraint in the NEM—involves New South Wales to Queensland exports being limited by a voltage collapse limit on loss of the largest generating unit in Queensland (QNI #1).[99] This constraint corresponds with the augmentation driver in the 2018 ISP of increasing transfer between Queensland and New South Wales.[100] While this constraint was not mentioned in the 2016 NTNDP, AEMO has stated to the AEMC that the 2016 NTNDP does include the upgrade options required to address this constraint.[101]

97 The chapter also identifies projects that TransGrid proposes to assist inter-regional transfers but which do not directly address constraints identified in AEMO's national transmission planning documents.

98 Correspondence with AEMO on 7 September 2018. See AEMO, Letter - Last Resort Planning Power (LRPP) request for information - expected inter-regional constraints, 27 November 2018.

99 Correspondence with AEMO on 7 September 2018.

100 AEMO has confirmed to the AEMC in correspondence on 7 September 2018 that the driver for augmentation in the 2018 ISP of increasing transfer between Queensland and New South Wales involves addressing this constraint. For more details regarding this and other drivers which are not related to inter-regional flows, see AEMO, *ISP Appendices*, July 2018, pp. 58-60; p. 68.

101 AEMO, Letter - Last Resort Planning Power (LRPP) request for information - expected inter-regional constraints, 27 November 2018. The upgrade options can be found in AEMO, *National Transmission Network Development Plan,* December 2016, p. 28.

The second expected constraint (QNI #2) involves flows from New South Wales to Queensland being limited by the thermal capacity of the Liddell-Muswellbrook-Tamworth and Liddell-Tamworth 330 kV lines.[102] This constraint corresponds with:

- The augmentation driver in the 2018 ISP of increasing transfer between Queensland and New South Wales.[103]
- Transmission limitations involving 330 kV lines between Dumaresq, New South Wales and Liddell, New South Wales that were identified in the 2016 NTNDP.[104]

The third expected constraint (QNI #3) is New South Wales to Queensland export being limited by the transient stability limits for a fault on either a Bulli Creek-Dumaresq or an Armidale-Dumaresq 330 kV circuit.[105] This constraint corresponds with:

- The augmentation driver of increasing transfer between Queensland and New South Wales in the 2018 ISP.[106]
- Transmission limitations involving 330 kV lines between Dumaresq, New South Wales and Bulli Creek, Queensland that were identified in the 2016 NTNDP.[107]

TransGrid and Powerlink have provided five possible proposals in their PSCR to augment the northern New South Wales and south Queensland transmission network and thereby increase the capacity of QNI.[108] Most of these options include several possible variants. TransGrid and Powerlink estimate that these five options would cost between $28 million and $2.1 billion, and have project delivery times that vary from 1-2 years to 5-6 years.[109] Most of the projects proposed in the PSCR were also featured in TransGrid's 2018 TAPR, while some also appeared in the 2018 ISP. AEMO indicated in its correspondence to the AEMC that several of these proposed solutions would resolve the three expected constraints on QNI.[110]

The first proposal from TransGrid and Powerlink (Option 1) entails incremental upgrades to the existing network to increase transfer capacity.[111] Option 1 has four variants:

- Option 1A involves uprating the Liddell to Tamworth lines and installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks.[112] TransGrid and Powerlink expect this option to increase northward transfer capacity to 770 MW and southward transfer capacity to 1,215 MW.[113] Option 1A has an estimated capex cost of

102 Correspondence with AEMO on 7 September 2018.

103 AEMO has confirmed to the AEMC in correspondence on 7 September 2018 that the driver for augmentation in the 2018 ISP of increasing transfer between Queensland and New South Wales involves addressing this constraint. For more details regarding this and other drivers which are not related to inter-regional flows, see AEMO, *ISP Appendices*, July 2018, pp. 58-60; p. 68.

104 AEMO, *National Transmission Network Development Plan*, December 2016, p. 37.

105 Correspondence with AEMO on 7 September 2018.

106 AEMO has confirmed to the AEMC in correspondence on 7 September 2018 that the driver for augmentation in the 2018 ISP of increasing transfer between Queensland and New South Wales involves addressing this constraint. For more details regarding this and other drivers which are not related to inter-regional flows, see AEMO, *ISP Appendices*, July 2018, pp. 58-60; p. 68.

107 AEMO, *National Transmission Network Development Plan*, December 2016, p. 38.

108 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

109 ibid.

110 Correspondence with AEMO on 7 September 2018.

111 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

112 ibid, p. 5.

$142 million and an expected delivery time of 2-3 years.[114] This option corresponds with a similar one proposed in TransGrid's 2018 TAPR.[115] It also corresponds with equivalent proposals in the 2018 ISP.[116] AEMO has identified these projects as being Group 1 projects for QNI in the 2018 ISP.[117] AEMO has also indicated that it considers this proposal would address all three identified inter-regional constraints.[118]

- Option 1B is similar to option 1A, but only involves uprating the Liddell to Tamworth lines.[119] TransGrid and Powerlink expect this option to increase northward transfer capacity to 535 MW and southward transfer capacity to 1,030 MW.[120] Option 1B has an estimated capex cost of $28 million and an expected delivery time of 2-3 years.[121] Option 1B corresponds with one part of a similar proposal in TransGrid's 2018 TAPR.[122] AEMO has identified this project as being a Group 1 project for QNI in the 2018 ISP.[123] It has also indicated that it considers this proposal would address the QNI #2 constraint.[124]
- Option 1C is similar to option 1A, but only involves installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks.[125] TransGrid and Powerlink expect this option to increase northward transfer capacity to 595 MW and southward transfer capacity to 1,180 MW.[126] Option 1C has an estimated capex cost of $114 million and an expected delivery time of 2-3 years.[127] As noted above, Option 1C corresponds with a part of a similar proposal in TransGrid's 2018 TAPR.[128] AEMO has identified these projects as being Group 1 projects for QNI in the 2018 ISP.[129] AEMO has

113 ibid.

114 ibid.

115 TransGrid's equivalent 2018 TAPR's proposal was to install new SVCs at Dumaresq and Tamworth; capacitor banks at Tamworth, Armidale and Dumaresq; and upgrades to 330 kV lines 83 (Liddell-Muswellbrook), 84 (Liddell to Tamworth) and 88 (Tamworth to Muswellbrook) to a 120°C temperature rating. For further details, see TransGrid, *New South Wales transmission annual planning report*, June 2018, p. 24.

116 AEMO's equivalent 2018 ISP proposals were to uprate the Liddell-Muswellbrook-Tamworth and Liddell-Tamworth 330 kV lines, SVCs at Dumaresq and Tamworth substations and shunt capacitor banks at Tamworth, Armidale and Dumaresq. For further details, see AEMO, *ISP Appendices*, Appendix D.3.5, July 2018, p. 68.

117 AEMO, *Integrated System Plan*, July 2018, p. 8. Listed as a Phase 1 project in AEMO, *ISP Appendices*, *D.1.* July 2018, p. 59. See also AEMO, *ISP Appendices*, Appendix D.3.5, July 2018, p. 68.

118 Correspondence with AEMO on 7 September 2018. See AEMO, *ISP Appendices*, July 2018, p. 68.

119 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

120 ibid.

121 ibid.

122 TransGrid's equivalent 2018 TAPR's proposal was upgrades to 330 kV lines 83 (Liddell-Muswellbrook), 84 (Liddell to Tamworth) and 88 (Tamworth to Muswellbrook) to a 120°C temperature rating. For further details, see TransGrid, *New South Wales transmission annual planning report*, June 2018, p. 24.

123 AEMO, *Integrated System Plan*, July 2018, p. 8. Listed as a Phase 1 project in AEMO, *ISP Appendices*, *D.1.* July 2018, p. 59. See also AEMO, *ISP Appendices*, Appendix D.3.5, July 2018, p. 68.

124 Correspondence with AEMO on 7 September 2018. See AEMO, *ISP Appendices*, July 2018, p. 68.

125 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

126 ibid.

127 ibid.

128 TransGrid's equivalent 2018 TAPR's proposal TransGrid's equivalent 2018 TAPR's proposal was to install new SVCs at Dumaresq and Tamworth, as well as capacitor banks at Tamworth, Armidale and Dumaresq. For further details, see TransGrid, *New South Wales transmission annual planning report*, June 2018, p. 24.

129 AEMO, *Integrated System Plan*, July 2018, p. 8. Listed as a Phase 1 project in AEMO, *ISP Appendices*, *D.1.* July 2018, p. 59. See also AEMO, *ISP Appendices*, Appendix D.3.5, July 2018, p. 68.

also indicated that it considers this proposal would address the QNI #1 and QNI #3 constraints.[130]

- Option 1D involves the Sapphire substation being cut into line 8C and a mid-point switching station between Dumaresq and Bulli Creek.[131] TransGrid and Powerlink expect this option to increase northward transfer capacity to 535 MW and southward transfer capacity to 1,165 MW. Option 1D has an estimated capex cost of $45 million and an expected delivery time of 1-2 years.[132] This option corresponds with a similar proposal in TransGrid's 2018 TAPR.[133] This proposal could address the QNI #3 constraint.

The second proposal from TransGrid and Powerlink (Option 2) entails a new single-circuit line from New South Wales to Queensland.[134] This involves a 330 kV single circuit between Braemar and Liddell.[135] TransGrid and Powerlink expect this option to increase northward transfer capacity to 980 MW and southward transfer capacity to 1,865 MW.[136] Option 2 has an estimated capex cost of $855 million and an expected delivery time of 3-4 years.[137] This option corresponds with a similar one proposed in TransGrid's 2018 TAPR.[138] This proposal could address QNI #1, QNI #2 and QNI #3.

The third proposal from Transgrid and Powerlink (Option 3) entails a new double-circuit line from New South Wales to Queensland.[139] Option 3 has three variants:

- Option 3A involves a 330 kV double circuit between Bulli Creek and Armidale.[140] TransGrid and Powerlink expect this option to increase northward transfer capacity to 770 MW and southward transfer capacity to 1,593 MW.[141] Option 3A has an estimated capex cost of $560 million and an expected delivery time of 3-4 years.[142] AEMO has identified this project as its preferred Group 2 project for QNI in the 2018 ISP.[143] It has also indicated that it considers this proposal would address all three identified constraints.[144]

130 Correspondence with AEMO on 7 September 2018.

131 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

132 ibid.

133 TransGrid's equivalent 2018 TAPR's proposal was turning both transmission lines along QNI into two switching stations at Sapphire and mid-way between Dumaresq and Bulli Creek. For further details, see TransGrid, *New South Wales transmission annual planning report*, June 2018, p. 24.

134 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

135 ibid.

136 ibid.

137 ibid.

138 TransGrid's equivalent 2018 TAPR's proposal was a new 330 kV single circuit transmission between Liddell and Western Downs via existing transmission substations. For further details, see TransGrid, *New South Wales transmission annual planning report*, June 2018, pp. 24-25.

139 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

140 ibid.

141 ibid.

142 ibid.

143 AEMO, *Integrated System Plan*, July 2018, p. 8. Listed as a Phase 2, Option A preferred project in AEMO, *ISP Appendices*, *D.1.* July 2018, p. 59. See also AEMO, *ISP Appendices*, Appendix D.3.5, July 2018, p. 68.

144 Correspondence with AEMO on 7 September 2018. See AEMO, *ISP Appendices*, July 2018, p. 68.

- Option 3B involves a 330 kV double circuit between Braemar and Liddell via Uralla, as well as the establishment of a Uralla 330 kV substation.[145] TransGrid and Powerlink expect this option to increase northward transfer capacity to 1,530 MW and southward transfer capacity to 2,160 MW.[146] Option 3B has an estimated capex cost of $1,505 million and an expected delivery time of 4-5 years.[147] This option corresponds with a similar one proposed in TransGrid's 2018 TAPR.[148] This proposal could address QNI #1, QNI #2 and QNI #3.
- Option 3C involves a 330 kV double circuit between Braemar and Uralla, and 500 kV single circuits between Uralla and Wollar and between Uralla and Bayswater, as well as the establishment of a Uralla 500/330 kV substation.[149] TransGrid and Powerlink expect this option to increase northward transfer capacity to 1,695 MW and southward transfer capacity to 2,540 MW.[150] Option 3C has an estimated capex cost of $2,039 million and an expected delivery time of 5-6 years.[151] This option corresponds with a similar one proposed in TransGrid's 2018 TAPR.[152] This proposal could address QNI #1, QNI #2 and QNI #3.

The fourth proposal from Transgrid and Powerlink (Option 4) entails HVDC options.[153] Option 4 has three variants:

- Option 4A involves an HVDC back-to-back.[154] TransGrid and Powerlink expect this option to increase northward transfer capacity to 1,195 MW and southward transfer capacity to 1,780 MW.[155] Option 4A has an estimated capex cost of $825 million and an expected delivery time of 2-3 years.[156] Option 4A corresponds with an equivalent proposal in the 2018 ISP.[157] AEMO has also identified this project as a possible Group 2 project for QNI in the 2018 ISP.[158] This option corresponds with a similar one proposed in TransGrid's 2018 TAPR.[159] This proposal could address QNI #1, QNI #2 and QNI #3.

145 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

146 ibid.

147 ibid.

148 TransGrid's equivalent 2018 TAPR's proposal was a new 330 kV double circuit transmission between Liddell and Western Downs via a diverse transmission path. For further details, see TransGrid, *New South Wales transmission annual planning report*, June 2018, pp. 24-25.

149 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

150 ibid.

151 ibid.

152 TransGrid's equivalent 2018 TAPR's proposal was a new 500 kV transmission between Bayswater/Wollar and Uralla, and new 330 kV transmission between Uralla and Western Downs. For further details, see TransGrid, *New South Wales transmission annual planning report*, June 2018, pp. 24-25.

153 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

154 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

155 ibid.

156 ibid.

157 AEMO's equivalent 2018 ISP proposal was 2x330 kV new circuits between Armidale and Bulli Creek. For further details, see AEMO, *ISP Appendices*, Appendix D.3.5, July 2018, p. 68.

158 AEMO, *Integrated System Plan*, July 2018, p. 8. Listed as a Phase 2, Option C project in AEMO, *ISP Appendices*, *D.1.* July 2018, p. 60.

159 TransGrid's equivalent 2018 TAPR's proposal was a back-to-back HVDC. For further details, see TransGrid, *New South Wales*

- Option 4B involves an HVDC between Mudgeeraba and Lismore.[160] TransGrid and Powerlink expect this option to increase northward transfer capacity to 765 MW and southward transfer capacity to 1,190 MW.[161] Option 4B has an estimated capex cost of $600 million and an expected delivery time of 3-4 years.[162] This option has not previously been proposed in a TNSP TAPR or in the 2018 ISP. This proposal could address QNI #1, QNI #2 and QNI #3.
- Option 4C involves an HVDC between Western Downs and Bayswater.[163] TransGrid and Powerlink expect this option to increase northward transfer capacity to 2,590 MW and southward transfer capacity to 2,990 MW.[164] Option 4C has an estimated capex cost of $2,100 million and an expected delivery time of 4-5 years.[165] This option has not previously been proposed in a TNSP TAPR or in the 2018 ISP. This proposal could address QNI #1, QNI #2 and QNI #3.

The fifth proposal from Transgrid and Powerlink (Option 5) entails a grid-connected battery system.[166] This involves installing a battery energy storage system.[167] TransGrid and Powerlink expect this option to increase northward transfer capacity to 1,135 MW and southward transfer capacity to 1,635 MW. Option 5 has an estimated capex cost of $1,000 million and an expected delivery time of 1-3 years.[168] This option corresponds with a similar one proposed in TransGrid's 2018 TAPR.[169] This proposal could address QNI #1, QNI #2 and QNI #3.

Several of these potential upgrades to QNI are recommended by AEMO for immediate investment in the suite of Group 1 projects proposed in the 2018 ISP.[170] Group 1 projects are those that AEMO considers requires 'near-term construction to maximise the economic use of existing resources.'[171]

The QNI upgrades that AEMO recommends as 2018 ISP Group 1 projects comprise:[172]

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transmission annual planning report, June 2018, pp. 24-25.

160 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

161 The PSCR notes that power transfer capabilities for this option are defined for both the existing HVAC interconnector and for the new HVDC option. For further details, see Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

162 ibid.

163 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

164 The PSCR notes that power transfer capabilities for this option are defined for both the existing HVAC interconnector and for the new HVDC option. For further details, see Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

165 ibid.

166 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018, p. 5.

167 ibid.

168 ibid.

169 TransGrid's equivalent 2018 TAPR's proposal was the use of batteries with fast response to increase stability limits. For further details, see TransGrid, *New South Wales transmission annual planning report*, June 2018, pp. 24-25.

170 AEMO, *Integrated System Plan*, July 2018, pp. 7-8. The details of the Group 1 projects are listed as Phase 1 projects in AEMO, *ISP Appendices*, *D.1.* July 2018, p. 59, with additional information regarding these projects in AEMO, *ISP Appendices*, *D.3.,* July 2018, p. 68.

171 ibid.

172 AEMO, *ISP Appendices*, July 2018, p. 59.

- uprate the Liddell – Muswellbrook 330 kV line
- uprate the Muswellbrook – Tamworth 330 kV line
- uprate the Liddell – Tamworth 330 kV lines
- install static VAR compensators (SVCs) at Dumaresq and Tamworth substations
- install shunt capacitor banks at Tamworth, Armidale and Dumaresq substations.

AEMO expects these projects would increase the transfer capacity towards New South Wales by 190 MW, and towards Queensland by approximately 460 MW.[173] The estimated cost of these projects is $142 million and AEMO stated in the 2018 ISP that the assets could be in service by 2020.[174] Table 5.2 shows the linkages between the 2018 ISP Group 1 projects and the PSCR-proposed options.

TransGrid has also proposed a separate NCIPAP project to install a 330 kV, 120 MVAr shunt capacitor bank at Armidale 330/132 kV substation in its 2018 TAPR.[175] TransGrid expects this development would increase QNI's voltage stability limits.[176] This project could help address QNI #1. TransGrid's project completion date is no later than June 2023, with an expected cost of $4.7 million.[177] The project has been included as a proposal in TransGrid's NCIPAP for the 2018-19 to 2022-23 period.[178]

TransGrid has identified an additional project in the New South Wales transmission network in its 2018 TAPR that would, if implemented, positively impact on inter-regional transfers across QNI. The proposal involves implementing an Armidale capacitor transfer tripping scheme for the Armidale 132 kV capacitor bank.[179] It addresses inter-regional constraints that were not identified by AEMO in the 2016 NTNDP or the 2018 ISP. TransGrid considers this would improve QNI's transfer capability during an outage of an Armidale 330/132 kV transformer.[180] The project completion is expected to be June 2023 at the latest, with an estimated cost of $0.2 million.[181] The proposal is in TransGrid's NCIPAP for the 2018-19 to 2022-23 period.[182]

5.3.3 Conclusion: QNI

In summary, all identified inter-regional constraints associated with QNI are being considered by the relevant TNSP. AEMO identified three expected inter-regional constraints on QNI. TransGrid and Powerlink are proposing five potential options to augment QNI, each comprising a suite of projects. The expected constraints are addressed by these various options and projects.

173 ibid.
174 ibid.
175 TransGrid, *New South Wales transmission annual planning report*, June 2018, p. 35.
176 ibid.
177 ibid.
178 AER, *Final Decision – TransGrid transmission determination 2018 to 2023*, May 2018, p. 15.
179 TransGrid, *New South Wales transmission annual planning report*, June 2018, p. 35.
180 ibid.
181 ibid.
182 AER, *Final Decision – TransGrid transmission determination 2018 to 2023*, May 2018, p. 15.

Table 5.2: **Identified NSW - QLD constraints and proposed solutions - QNI**

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in AEMO Correspondence	QNI #1: New South Wales to Queensland export is limited by a voltage collapse limit on loss of the largest generating unit in Queensland	Several PSCR options could address this constraint, including: • Uprating the Liddell to Tamworth lines and installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (PSCR Option 1A) • Installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (PSCR Option 1C) • A new single-circuit line from New South Wales to Queensland (PSCR Option 2) • A 330 kV double circuit between Bulli Creek and Armidale (PSCR Option 3A) • A 330 kV double circuit between Braemar and Liddell via Uralla, as well as the establishment of a Uralla 330 kV substation (PSCR Option 3B) • A 330 kV double circuit between Braemar and Uralla, and 500 kV single circuits between Uralla and Wollar and between Uralla and Bayswater, as well as the establishment of a Uralla 500/330 kV substation (PSCR Option 3C)	Proposed by Powerlink and TransGrid in their RIT-T PSCR	Indicative cost ranges from $114 million to $2.1 billion depending on the option chosen Expected delivery time varies between 2-3 years and 5-6 years.	PSCR Option 1A and Option 1C involve 2018 ISP Group 1 projects.

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
		• An HVDC back-to-back (PSCR Option 4A) • An HVDC between Mudgeeraba and Lismore (PSCR Option 4B) • An HVDC between Western Downs and Bayswater (PSCR Option 4C) • A grid-connected battery system (PSCR Option 5)			
Identified in 2016 NTNDP, 2018 ISP and AEMO Correspondence	QNI #2: New South Wales to Queensland export is limited by the thermal capacity of Liddell-Muswellbrook-Tamworth and Liddell-Tamworth 330 kV lines	Several PSCR options could address this constraint, including: • Uprating the Liddell to Tamworth lines and installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (PSCR Option 1A) • Uprating the Liddell to Tamworth lines (PSCR Option 1B) • A new single-circuit line from New South Wales to Queensland (PSCR Option 2) • A 330 kV double circuit between Bulli Creek and Armidale (PSCR Option 3A) • A 330 kV double circuit between Braemar and Liddell via Uralla, as well as the establishment of a Uralla 330 kV substation (PSCR Option 3B)	Proposed by Powerlink and TransGrid in their RIT-T PSCR	Indicative cost ranges from $28 million to $2.1 billion depending on the option chosen Expected delivery time varies between 2-3 years and 5-6 years.	PSCR Option 1A and Option 1B involve 2018 ISP Group 1 projects.

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
		• A 330 kV double circuit between Braemar and Uralla, and 500 kV single circuits between Uralla and Wollar and between Uralla and Bayswater, as well as the establishment of a Uralla 500/330 kV substation (PSCR Option 3C) • An HVDC back-to-back (PSCR Option 4A) • An HVDC between Mudgeeraba and Lismore (PSCR Option 4B) • An HVDC between Western Downs and Bayswater (PSCR Option 4C) • A grid-connected battery system (PSCR Option 5)			
Identified in 2016 NTNDP, 2018 ISP and AEMO Correspondence	QNI #3: Queensland to New South Wales export is mainly limited by the transient stability limits for a fault on either a Bulli Creek-Dumaresq or Armidale-Dumaresq 330 kV	Several PSCR options could address this constraint, including: • Uprating the Liddell to Tamworth lines and installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (Option 1A) • Installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (PSCR Option 1C)	Proposed by Powerlink and TransGrid in their RIT-T PSCR	Indicative cost ranges from $45 million to $2.1 billion depending on the option chosen Expected delivery time varies between 1-2 years and 5-6 years.	PSCR Option 1A and Option 1C involve 2018 ISP Group 1 projects.

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
	circuit	• Cutting the Sapphire substation into line 8C and a mid-point switching station between Dumaresq and Bulli Creek (PSCR Option 1D) • A new single-circuit line from New South Wales to Queensland (PSCR Option 2) • A 330 kV double circuit between Bulli Creek and Armidale (PSCR Option 3A) • A 330 kV double circuit between Braemar and Liddell via Uralla, as well as the establishment of a Uralla 330 kV substation (PSCR Option 3B) • A 330 kV double circuit between Braemar and Uralla, and 500 kV single circuits between Uralla and Wollar and between Uralla and Bayswater, as well as the establishment of a Uralla 500/330 kV substation (PSCR Option 3C) • An HVDC back-to-back (PSCR Option 4A) • An HVDC between Mudgeeraba and Lismore (PSCR Option 4B) • An HVDC between Western Downs and Bayswater (PSCR Option 4C) • A grid-connected battery system (PSCR Option 5)			

5.3.4 Conclusion: Terranora interconnector

AEMO has not forecast any inter-regional constraints involving the Terranora interconnector in its 2016 NTNDP, 2018 ISP or additional advice provided by AEMO to the AEMC.

TransGrid and Powerlink did not identify any planned projects in their 2018 TAPRs or in TransGrid and Powerlink's 2018 PSCR report that would have an impact on interregional flows involving the Terranora interconnector in either the New South Wales or the Queensland transmission network.[183]

183 Powerlink and TransGrid, *Expanding NSW-QLD transmission transfer capacity – Project Specification Consultation Report,* November 2018.

6 REVIEW OF VICTORIA - NEW SOUTH WALES CONGESTION

BOX 6: SUMMARY OF FINDINGS

All transmission network inter-regional constraints forecast to affect flows between Victoria and New South Wales are being addressed by the relevant TNSPs in their transmission annual planning reports. This includes all inter-regional constraints relevant to the Victoria – New South Wales interconnector. 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 chapter provides the Commission's analysis of whether there are any significant inter-regional constraints affecting the flows between Victoria and New South Wales that are not being addressed by the relevant TNSPs. The chapter:

- Describes the Victoria - New South Wales (VNI) interconnector.
- Reviews inter-regional constraints between Victoria and New South Wales by examining:
  - The constraints expected to affect this interconnector into the future based on an examination of AEMO's 2018 ISP, the 2016 NTNDP and additional written advice provided by AEMO to the AEMC.
  - The binding constraint equations that had the highest market impact in 2017 (from AEMO's 2018 NEM constraint data).
- Reviews TransGrid and AEMO's 2018 TAPRs and the Victoria to New South Wales Interconnector Upgrade PSCR regarding projects that address inter-regional constraints affecting VNI.[184]
- Compares the projects that TransGrid and AEMO identify in these reports with AEMO's expected inter-regional constraint forecasts to identify if there are any 'gaps' where a TNSP has not responded to an expected inter-regional constraint identified by AEMO.

6.1 Introduction

6.1.1 Historical flows between Victoria and New South Wales

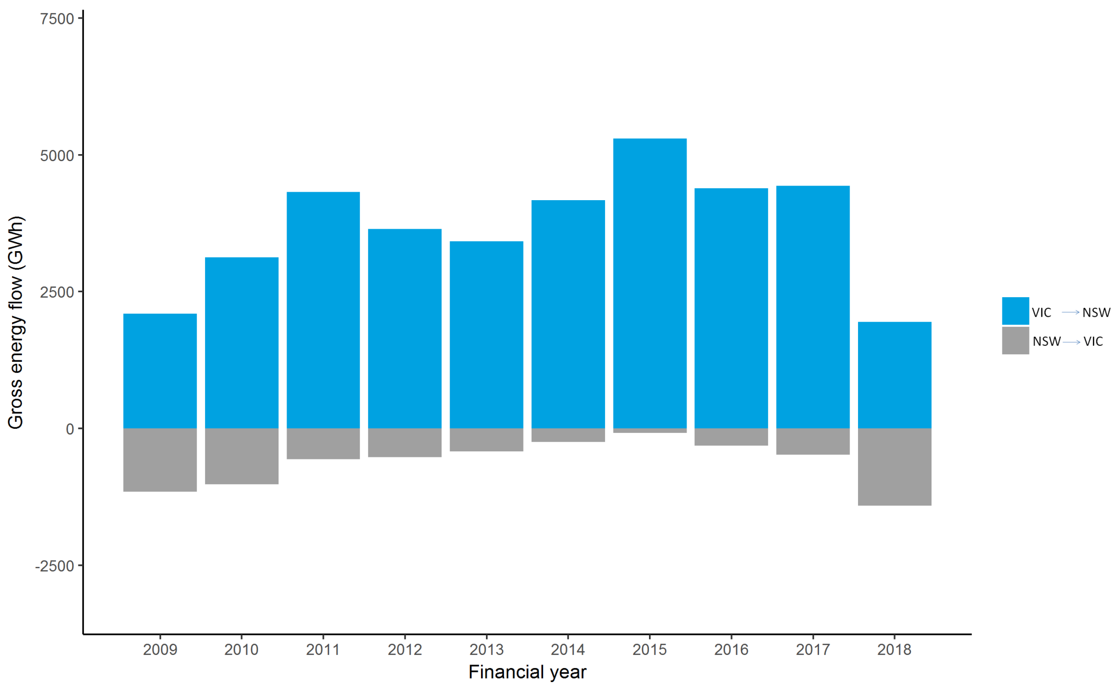
Chart 6.1 presents the annual flows of electricity between Victoria and New South Wales over the last ten financial years.[185] The negative flows indicate Victorian imports and the positive flows indicate Victorian exports. The chart shows:

184 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018.

185 This chart includes all constraints binding VNI, including any system normal or outage constraints. The financial year as reported in the chart encompasses the first half of that year and the second half of the previous year; i.e. 2018 represents the 2017/18 financial year.

- Victorian exports to New South Wales have traditionally been much larger than Victorian imports from New South Wales.
- Victorian exports to New South Wales fell significantly in 2017/2018 and reached a lower level than at any other time during the last 10 years.
- Victorian imports from New South Wales significantly increased in 2017/2018 and reached a higher flow level than at any other time during the last 10 years.

Figure 6.1: Inter-regional flows between Victoria and NSW (2009 - 2018)



One interconnector transports electricity in the NEM between Victoria and New South Wales; VNI.

6.1.2 The Victoria - New South Wales interconnector (VNI)

VNI is an alternating current connection connecting northern Victoria with southern New South Wales. It is defined as the flow across the:[186]

- 330 kV line between Murray and Upper Tumut
- 330 kV line between Murray and Lower Tumut
- 330 kV line between Jindera and Wodonga
- 220 kV line between Buronga and Red Cliffs
- 132 kV bus tie at Guthega (which is normally open).

186 AEMO, *Interconnector Capabilities,* November 2017, p. 5.

The 330 kV lines link southern New South Wales with areas in northern Victoria which contain 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).[187] The 220 kV line between Buronga in New South Wales and Red Cliffs in Victoria delivers supply to Victorian load centres such as Bendigo and Ballarat and also transfers power to South Australia via the Murraylink interconnector.[188]

VNI currently has a nominal capacity of:[189]

- 700-1,600 MW from Victoria to NSW
- 400-1,350 MW from NSW to Victoria.

In terms of recent flows on VNI, Figure 6.2 shows all flows during the 2016-2017 financial year and Figure 6.3 shows all flows during the 2017-2018 financial year.[190] Flows from Victoria to New South Wales are shown as positive, and flows from New South Wales to Victoria appear as negative.The chart also shows (in purple) when inter-regional constraints have limited the flows on the interconnector below its maximum capacity (i.e. constraints have 'bound') in each direction.[191] While bound constraints generally occur below a certain 'maximum' level, sometimes constraints can be bound to prevent the flows from falling below a 'minimum' level.

187 AEMO, *NEM Constraint Report 2016,* June 2017, p. 27.

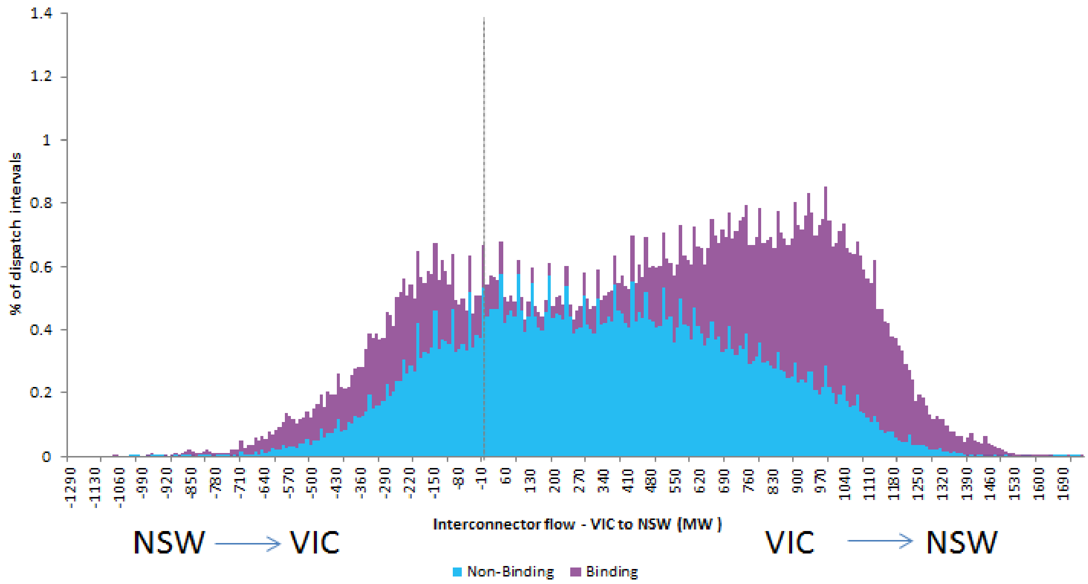
188 ibid.

189 AEMO, *Interconnector Capabilities*, November 2017, p. 5. The nominal capacity of VNI is highly dependent on the output of Murray generators (for New South Wales to Victoria) and Lower/Upper Tumut generators (for Victoria to New South Wales). VNI can bind in either direction for high demand in New South Wales or Victoria.

190 These charts include all constraints binding VNI, including any system normal or outage constraints.

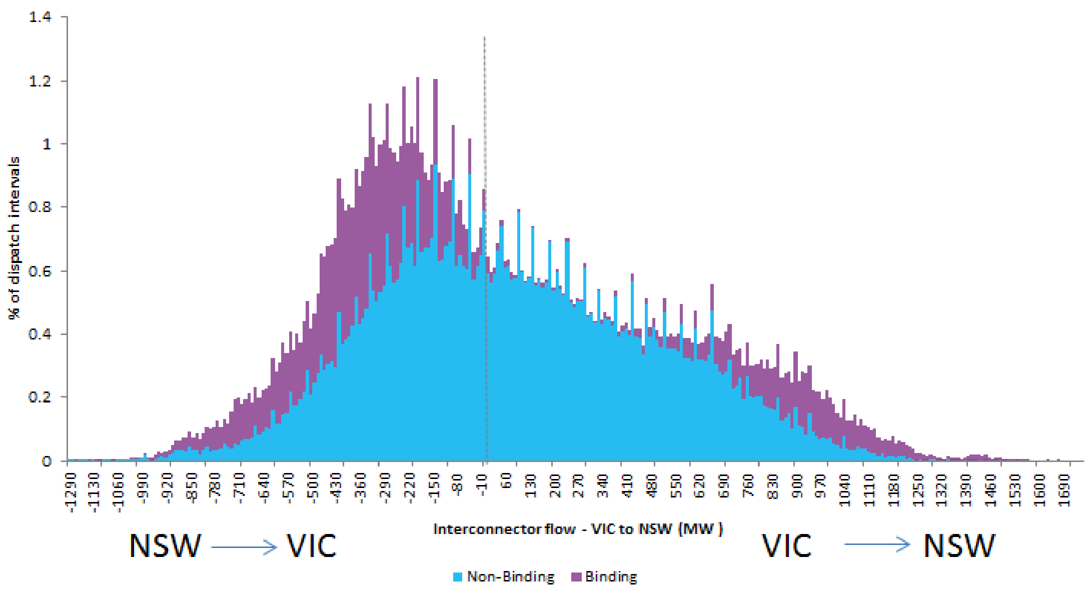
191 A constraint is said to be 'binding' when AEMO cannot dispatch the lowest bid priced generation because of network constraints. A constraint is said to be an inter-regional constraint if it impacts on flows between NEM regions. That is, if the constraint limits flows on an interconnector (see Chapter 3, section 3.2.2).

Figure 6.2: Inter-regional flows via VNI (2016 - 2017)



Source: AEMC analysis of Neopoint database.
Note: This figure covers financial years.

Figure 6.3: Inter-regional flows via VNI (2017 - 2018)



Source: AEMC analysis of Neopoint database.
Note: This figure covers financial years.

These charts indicate a trend of increasing flows from New South Wales to Victoria, and decreasing flows from Victoria to New South Wales at lower flow rates through VNI. The chart shows that flows from New South Wales to Victoria increased in 2017-18 compared to the previous year, particularly at flows with rates lower than 710 MW. In regards to flows from Victoria to New South Wales, flows at rates higher than 270 MW were less frequent in 2017-18 than in 2016-2017, while flows with rates lower than 270 MW were at similar levels in both years, or were slightly higher in 2017-18 than in 2016-2017.

Flows from New South Wales to Victoria bound more often at both high and low flow levels in 2017-18 than in 2016-17. Victoria to New South Wales flows bound much less frequently in 2017-18 than in 2016-17 across all flow levels. Flows more commonly approached the maximum New South Wales to Victoria nominal capacity of 1,350 MW in 2017-18 than in 2016-17, and less commonly approached the maximum Victoria to New South Wales nominal capacity of 1,600 MW in 2016-17 than in 2017-18.

6.2 Current inter-regional constraints affecting Victoria – New South Wales flows

This section outlines the major binding inter-regional constraints that currently affect Victoria – New South Wales flows (in both directions). It examines binding constraints in terms of their total market impact, with a focus on system normal constraints.[192] The information and analysis in this section is based on AEMO data on constraint equation performance for the 2017 calendar year.[193]

In 2017, the total market impact of inter-regional system normal constraints was higher for electricity flows from Victoria to New South Wales than for flows in the other direction.[194] The market impact of inter-regional system normal constraints was higher in both directions in 2017 than during the previous year.[195]

Five of the top ten (by total market impact) inter-regional binding system normal constraints for all the interconnectors in the NEM are associated with flows between Victoria and New South Wales.[196] Table 6.1 shows that:

- Four out of the five constraints which affected Victoria – New South Wales flows involved exports from Victoria to New South Wales.
- The top constraint by individual market impact affected Victorian imports.
- The market impact of three out of the five constraints which affected Victoria – New South Wales flows increased in 2017 compared to 2016, and the market impact of the other two constraints decreased in 2017 compared to 2016.
- Some of the major constraints that bound on Victoria – New South Wales flows in 2017 also limited flows on other interconnectors which link Victoria to other states (such as the Heywood interconnector).[197] It follows that multiple interconnectors can be constrained by the same transmission network limitation(s).

192 See Chapter 3, section 3.2.5 for an explanation of 'market impact' and how it is calculated. System normal constraints do not include constraints caused by outages of transmission elements or frequency control ancillary service requirements.

193 AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

194 Analysis based on figures from AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

195 ibid.

196 The top ten constraints are listed in Chapter 3, section 3.2.5, Table 3.2. Additional detail regarding the listed constraints is also located in AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

197 See Table 3.2 in Chapter 3, section 3.2.5.

Table 6.1: **Current major inter-regional system normal constraints affecting Victoria - New South Wales**

2017 NEM MARKET IMPACT RANKING AND AEMO EQUATION ID[1]	MARKET IMPACT[2] ($2017)		DESCRIPTION[3]	HOURS BINDING		FLOW DIRECTION
	2017	2016		2017	2016	
2a N^^V_NIL_1 Voltage stability	736,588	43,476	This constraint is used to provide voltage stability, which is used for managing transmission voltages so that they remain at acceptable levels if a credible contingency occurs instead of collapsing. The relevant contingency event is the loss of the largest Victorian generating unit or the Basslink interconnector	1806	82	VNI Victoria import
6 N>>N-NIL__B_15M Thermal overload	237,706	2,493	This thermal overload constraint is used to avoid overloading the Upper Tumut to Canberra line in NSW and the ACT in the case of a trip of the Lower Tumut to Canberra line	4	0.2	VNI Victoria export
7b V>>SML_NIL_8 Thermal overload	185,107	82	This thermal overload constraint is used to avoid overloading the Ballarat to Bendigo 220 kV line in Victoria in the case of a trip of Shepparton to Bendigo 220 kV line	2	0.3	VNI Victoria export
8a V::N_NILxxx Transient stability	181,973	244,494	This constraint is used to provide transient stability for Yallourn Power Station in the case of a supply interruption of a 500 kV line from Heywood in Victoria to South East in South Australia	581	942	VNI Victoria export
10b	143,897	147,950	This is a thermal overload constraint used to	286	957	VNI

2017 NEM MARKET IMPACT RANKING AND AEMO EQUATION ID[1]	MARKET IMPACT[2] ($2017)		DESCRIPTION[3]	HOURS BINDING		FLOW DIRECTION
	2017	2016		2017	2016	
V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P Thermal overload			manage the power flow on a transmission element so that it does not exceed a rating (either continuous or short term) under normal conditions or following a credible contingency. It is used to avoid overloading the South Morang 500/330 kV (F2) transformer when there are no contingencies and radial/parallel modes occur involving Yallourn W1 and the 500 or 220 kV lines to which the generator is connected.			Victoria export

Source: AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018

Note: 1 - System normal constraints do not include constraints caused by outages of transmission elements. The table does not include constraints involving FCAS requirements. This table uses calendar years, and the constraints are categorised by market impact. The inter-regional constraints in this table are the constraints relevant to this chapter from the top 10 inter-regional constraints by total market impact for the entire NEM (2017) presented in Table 3.2.

Note: 2 - 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 over a year to provide a total marginal market impact. A 2.5 per cent inflation rate is assumed for 2016.

Note: 3 - Additional details regarding the listed constraints are located in AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

6.3 Expected inter-regional constraints and TNSP proposed projects

6.3.1 Sources considered

This section examines whether all expected inter-regional constraints affecting flows between Victoria and New South Wales are being adequately addressed by the relevant TNSP. It presents the inter-regional constraints that AEMO in its national transmission planning role expects are likely to affect flows between Victoria and New South Wales. The sources included in the analysis are AEMO's 2016 NTNDP, the 2018 ISP and additional written advice AEMO has provided to the AEMC.

The section then identifies relevant projects that TransGrid and AEMO (in its Victorian transmission network planning role) propose in their 2018 annual planning reports, and in the PSCR on Victoria to New South Wales interconnector upgrades, published in November 2018.

The section then compares the projects that TransGrid and AEMO identify in their reports with AEMO's expected inter-regional constraints, to identify if there are any 'gaps' where a TNSP has not responded to the expected inter-regional constraint identified by AEMO.

6.3.2 Findings: Victoria – New South Wales interconnector (VNI) - TransGrid

AEMO has identified eight expected inter-regional constraints on VNI.[198] Two of these expected constraints involve the New South Wales transmission network.

The first expected constraint in the New South Wales transmission network involves Victorian exports to New South Wales being limited by transmission limitations on the Sydney to Canberra/Yass 330 kV corridor during times with increased generation in southern New South Wales and high export from Victoria to New South Wales (VNI #1).[199] The constraint corresponds to:[200]

- In the 2018 ISP, the augmentation drivers of New South Wales coal-fired generation retirements and increased generation in southern New South Wales, Murray and Riverland renewable energy zones and increased import from Victoria.
- In the 2016 NTNDP, transmission limitations on the 330 kV cutset between Yass/Canberra and Sydney.

The second expected constraint in the New South Wales transmission network involves Victorian exports to New South Wales being limited by the thermal capacity of the Upper Tumut – Canberra 330 kV line (VNI #2).[201] The constraint corresponds to:[202]

198 Termed potential limitations in AEMO's 2016 NTNDP.

199 Correspondence with AEMO on 7 September 2018.

200 ibid. See AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 72. See also AEMO, *National Transmission Network Development Plan*, December 2016, p. 38.

201 Correspondence with AEMO on 7 September 2018.

202 ibid. See AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 72. See also AEMO, *National Transmission Network Development Plan*, December 2016, p. 37.

- In the 2018 ISP, the augmentation driver of increased export from Victoria to New South Wales.
- In the 2016 NTNDP, transmission limitations on the 330 kV cutset between Yass/Canberra and Sydney.

AEMO and TransGrid have provided three possible options in their PSCR to address VNI #1 and VNI #2. All three options include projects that could augment the southern New South Wales transmission network and thereby increase the capacity of VNI.[203] AEMO indicated in correspondence to the AEMC that several of these proposals would resolve the two constraints on VNI associated with the New South Wales transmission network.[204]

- One possible solution being considered by AEMO and TransGrid entails uprating the Canberra – Upper Tumut 330 kV line.[205] AEMO has identified this project as being a Group 1 project for VNI in the 2018 ISP.[206] This project is part of the PSCR's Option 1, and was also included in the PSCR's Options 2 and 3, which are expected to provide additional higher capacity upgrades in Victoria and New South Wales.[207] A similar project was also proposed in TransGrid's 2018 TAPR.[208] The uprating solution has an estimated cost of $28 million and an expected lead time of 27 months. This proposal could address VNI #1 and VNI #2.
- The second solution being considered by AEMO and TransGrid entails uprating the existing 330 kV lines between the Snowy Mountains Scheme and Sydney, as well as the Canberra – Upper Tumut line.[209] This project is part of the PSCR's Options 2 and 3.[210] Similar projects were also proposed in TransGrid's 2018 TAPR.[211] This solution has an estimated cost of $36-112 million and an estimated lead time of 44-63 months.[212] TransGrid in its 2018 TAPR considered that a similar TAPR proposal would increase VNI's capacity by 160 MW.[213] This proposal could address VNI #1 and VNI #2.

203 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

204 Correspondence with AEMO on 7 September 2018.

205 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

206 AEMO, *Integrated System Plan*, July 2018, p. 8. Listed as a Stage 1 project in AEMO, *ISP Appendices*, *D.1.* July 2018, p. 61. See also AEMO, *ISP Appendices*, Appendix D.3.5, July 2018, p. 72.

207 ibid.

208 TransGrid's equivalent 2018 TAPR's proposal was carrying out staged upgrades of the 330 kV lines 39 and Canberra - Upper Tumut (O1) to meet a 120°C design temperature. For further details, see TransGrid, *New South Wales transmission annual planning report*, June 2018, p. 23.

209 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

210 ibid.

211 TransGrid's equivalent 2018 TAPR proposals were carrying out staged upgrades of the 330 kV lines 39 and Canberra - Upper Tumut (O1) to meet a 120°C design temperature, as well as upgrading the Yass-Murulan, Canberra – Yass, Kangaroo Valley - Dapto, Sydney West – Bannaby, and Yass – Gullen Range 330 kV lines (lines 4, 5, 9, 18, 39, 61 3J) to meet a 120°C design temperature. For further details, see TransGrid, *NewSouth Wales transmission annual planning report*, June 2018, p. 23.

212 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

213 This TAPR proposal does not include uprating the Canberra - Upper Tumut line. For further details, see TransGrid, *NewSouth Wales transmission annual planning report*, June 2018, p. 23.

- The third solution being considered by AEMO and TransGrid entails bringing forward a new 500 kV single circuit line between the Snowy Mountains Scheme and Bannaby.[214] This project is the PSCR's Options 2a and 3a, which are expected to provide additional higher capacity upgrades in Victoria and New South Wales.[215] It is also a Group 2 project in the 2018 ISP and has been mentioned as an option associated with Snowy 2.0 in TransGrid's 2018 TAPR.[216] This solution has an estimated cost of $520 million and an estimated lead time of 47 months.[217] This proposal could address VNI #1 and VNI #2.

TransGrid's 2018 TAPR provided another solution that could address VNI #1 which was not discussed in the PSCR. This option is to conduct rebuilds of 330 kV lines 4, 5, 9, 18, 39, 61 and 3J to ratings between 1,300 MW and 2,100 MW.[218] TransGrid considers this proposal would increase VNI's transfer capacity by 1,000 MW.[219] The proposal has an estimated cost of $393 million and does not have an estimated project completion date.[220]

TransGrid's 2018 TAPR also identified a project that would positively impact on VNI flows and address a constraint not identified by AEMO in its national transmission planning role. This project and the associated inter-regional constraint is to install a 330 kV 100 MVAr shunt capacitor bank at Wagga substation.[221] This development would relieve a voltage stability limitation which constrains power transfers into Victoria to a level that would prevent voltage collapse in southern New South Wales if a credible contingency event occurs in Victoria (loss of the largest Victorian generating unit or the Basslink interconnector).[222] TransGrid has received approval for a NCIPAP project to install a 100 MVAr capacitor in southern New South Wales to relieve this voltage stability limitation.[223]

6.3.3 Findings: Victoria – New South Wales interconnector (VNI) – Victoria

AEMO has identified eight expected inter-regional constraints on VNI[224], with six of these identified constraints involving the Victorian transmission network.

The first expected constraint in the Victorian transmission network involves Victorian exports to New South Wales being limited by the thermal capacity of the South Morang 500/330 kV transformer (VNI #3).[225] The constraint corresponds with:

214 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

215 ibid.

216 AEMO, *Integrated System Plan*, July 2018, p. 8. Listed as a Stage 2 project in AEMO, *ISP Appendices*, *D.1.* July 2018, pp. 61-62. See also TransGrid, *New South Wales transmission annual planning report*, June 2018, p. 22.

217 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

218 TransGrid, *NewSouth Wales transmission annual planning report*, June 2018, p. 23.

219 ibid.

220 ibid.

221 ibid, p. 39.

222 AEMO, *Victorian annual planning report*, July 2018, p. 31.

223 ibid. See also AER, *Final Decision –TransGrid transmission determination 2018 to 2023*, May 2018, p. 16.

224 Termed potential limitations in AEMO's 2016 NTNDP.

225 Correspondence with AEMO on 7 September 2018.

- The augmentation driver of increased export from Victoria to New South Wales in the 2018 ISP.[226]
- A transmission limitation on the South Morang 500/330 kV transformer in the 2016 NTNDP.[227]

Each of AEMO and TransGrid's three possible options in their PSCR include a project that could address this constraint.[228]

- The proposal being considered by AEMO and TransGrid entails the installation of a new 500/330 kV transformer at South Morang.[229] This project is part of the PSCR's Option 1, Option 2 and Option 3.[230] This project was also proposed in AEMO's 2018 VAPR.[231] A similar solution proposed entails replacing the existing South Morang F2 transformer with a transformer with higher capacity.[232] Installation of a new 500/330 kV transformer at South Morang has an estimated cost of $29 million and an expected lead time of 36 months.[233] AEMO has identified the installation of an additional new transformer at South Morang as being a Group 1 project for VNI in the 2018 ISP.[234]

The second expected constraint in the Victorian transmission network involves Victorian exports to New South Wales being limited by the thermal capacity of Dederang-South Morang 330 kV circuits (VNI #4).[235] The constraint corresponds with:

- The augmentation driver of increased export from Victoria to New South Wales in the 2018 ISP.[236]
- Transmission limitations on Dederang-South Morang 330 kV circuits in the 2016 NTNDP.[237]

AEMO and TransGrid provide three possible options that could address this constraint in their PSCR.[238]

- One possible solution entails uprating the South Morang – Dederang 330 kV lines by conductor re-tensioning and associated works (including uprating of series capacitors) to

226 AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 72.

227 AEMO, *National Transmission Network Development Plan*, December 2016, p. 38.

228 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10. AEMO indicated in correspondence to the AEMC on 7 September 2018 that several of these proposed solutions would resolve this constraint on VNI identified in the Victorian transmission network.

229 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

230 ibid.

231 AEMO's equivalent 2018 VAPR's proposal was installing an additional new 500/330 kV transformer at South Morang. For further details, see AEMO, *Victorian transmission annual planning report*, July 2018, p. 29; p. 44.

232 ibid.

233 ibid.

234 AEMO, *Integrated System Plan*, July 2018, p. 8. Listed as a Stage 1 project in AEMO, *ISP Appendices*, *D.1.* July 2018, p. 61. See also AEMO, *ISP Appendices*, Appendix D.3.5, July 2018, p. 72.

235 Correspondence with AEMO on 7 September 2018.

236 AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 72.

237 AEMO, *National Transmission Network Development Plan*, December 2016, p. 42.

238 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10. AEMO indicated in correspondence to the AEMC on 7 September 2018 that several of these proposed solutions would resolve this constraint on VNI identified in the Victorian transmission network.

allow the line to run to thermal rating.[239] This project is part of the PSCR's Option 1 and Option 2.[240] A similar project was also proposed in AEMO's 2018 VAPR.[241] The uprating solution has an estimated cost of $17 million and an expected lead time of 30 months.[242] AEMO has identified this project as being a Group 1 project for VNI in the 2018 ISP.[243]

- The second solution entails replacing the existing South Morang – Dederang 330 kV lines with higher capacity conductors and associated works. This project is part of the PSCR's Option 3.[244] A similar project was discussed in AEMO's 2018 TAPR.[245] The estimated cost and an estimated lead time for this solution are still to be determined.[246] This proposal could address VNI #1 and VNI #2.
- The third solution being considered by AEMO and TransGrid entails a new single circuit line (with series compensation) in parallel with the existing South Morang - Dederang 330 kV lines. This project is the PSCR's Option 3b.[247] A similar project was discussed in AEMO's 2018 TAPR.[248] This solution has an estimated cost of $370 million and an estimated lead time of 60 months.[249]

The third expected constraint in the Victorian transmission network involves Victorian exports to New South Wales being limited by a transient stability limit for a 2 phase to ground fault on a South Morang-Hazelwood 500 kV line (VNI #5).[250] The constraint corresponds with:

- The augmentation driver of increased export from Victoria to New South Wales in the 2018 ISP.[251]
- In the 2016 NTNDP, this was not identified as a material limitation in the scenarios modelled. However, a braking resister at Loy Yang was proposed as an augmentation project.[252]

239 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

240 ibid.

241 AEMO's equivalent 2018 VAPR's proposal was uprating two existing lines to 82 ºC (conductor temperature) operation and series compensation. For further details, see AEMO, *Victorian Annual Planning Report 2018*, July 2018, p. 29; p. 44; p. 47.

242 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

243 AEMO, *Integrated System Plan*, July 2018, p. 8. Listed as a Stage 1 project in AEMO, *ISP Appendices*, *D.1.* July 2018, p. 61. See also AEMO, *ISP Appendices*, Appendix D.3.5, July 2018, p. 72.

244 ibid.

245 AEMO's 2018 VAPR discussed more substantial upgrades as an option to address the South Morang - Dederang 330 kV line limitation. For further details, see AEMO, *Victorian Annual Planning Report 2018*, July 2018, p. 29.

246 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

247 ibid.

248 AEMO's 2018 VAPR discussed a new circuit as an option to address the South Morang - Dederang 330 kV line limitation. For further details, see AEMO, *Victorian Annual Planning Report 2018*, July 2018, p. 29.

249 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

250 Correspondence with AEMO on 7 September 2018.

251 AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 72.

252 AEMO, *National Transmission Network Development Plan*, December 2016, p. 28.

AEMO and TransGrid have provided four possible options to address this constraint in their PSCR.[253]

- One possible solution entails the installation of a braking resistor.[254] This project is part of the PSCR's Options 1, 2 and 3.[255] A similar project was also proposed in AEMO's 2018 VAPR.[256] The uprating solution has an estimated cost of $13 million and an expected lead time of 24 months.[257] AEMO has identified this project as being a Group 1 project for VNI in the 2018 ISP.[258]
- The second solution entails the installation of a synchronous condenser with inertia support. This project is the PSCR's Option 1a, an alternative to the braking resistor project.[259] This project was not explicitly identified as an option in AEMO's 2018 VAPR or AEMO's 2018 ISP, although the 2018 VAPR did identify non-network solutions as an option to address this constraint, which could include a synchronous condenser with inertia support.[260] This solution has an estimated cost of $20 million and an estimated lead time of 30 months.[261]
- The third solution entails the installation of a static VAR compensator (SVC). This project is the PSCR's Option 1b, an alternative to the braking resistor project.[262] This project was not explicitly identified as an option in AEMO's 2018 VAPR or AEMO's 2018 ISP, although the 2018 VAPR did suggest that network options such as a braking resistor could address this constraint, and an SVC could represent such a network option.[263] This solution has an estimated cost of $19 million and an estimated lead time of 30 months.[264]
- The fourth solution entails the installation of batteries with fast response inverters.[265] This project is the PSCR's Option 1c, an alternative to the braking resistor project.[266] This project was not explicitly identified as an option in AEMO's 2018 VAPR or AEMO's 2018 ISP, although the 2018 VAPR did identify non-network solutions as an option to address this constraint, which could include the installation of batteries with fast response

253 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10. AEMO indicated in correspondence to the AEMC on 7 September 2018 that several of these proposed solutions would resolve this constraint on VNI identified in the Victorian transmission network.

254 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

255 ibid.

256 AEMO, *Victorian Annual Planning Report* 2018, July 2018, p. 29.

257 ibid.

258 AEMO, *Integrated System Plan*, July 2018, p. 8. Listed as a Stage 1 project in AEMO, *ISP Appendices*, *D.1.* July 2018, p. 61. See also AEMO, *ISP Appendices*, Appendix D.3.5, July 2018, p. 72.

259 ibid.

260 AEMO, *Victorian Annual Planning Report 2018*, July 2018, p. 29.

261 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

262 ibid.

263 AEMO, Victorian Annual Planning Report 2018, July 2018, p. 29.

264 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

265 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission*, November 2018, p. 9.

266 ibid.

inverters.[267] This solution has an estimated lead time of 30 months, with the estimated cost of the project still to be determined.[268]

The fourth expected constraint in the Victorian transmission network involves Victorian imports from New South Wales being limited by the thermal capacity of the Murray – Dederang 330 kV line (VNI #6).[269] The constraint corresponds to:

- The augmentation driver of increased import from New South Wales to Victoria at times of high demand periods coinciding with high ambient temperature.[270]

In the 2016 NTNDP, this was not identified as a material limitation in the scenarios modelled by AEMO.[271]

AEMO and TransGrid did not discuss solutions to address this constraint in their PSCR. AEMO did propose two solutions to address this expected constraint in their 2018 VAPR. The VAPR indicated that project selection is yet to be determined. AEMO is currently investigating options such as these to increase import capacity from New South Wales to Victoria.[272] The three solutions proposed are:[273]

- Implement a load-shedding scheme to allow for operating the line to a higher thermal rating. AEMO did not provide an indicative cost for this project in the 2018 VAPR.
- Installing a third 1,060 MVA 330 kV line between Murray and Dederang. This proposal has an estimated cost of $183.9 million (excluding easement costs).
- Installing a second 330 kV line from Dederang to Jindera. This proposal has an estimated cost of $152 million (excluding easement costs).

The fifth identified constraint in the Victorian transmission network involves Victorian imports from New South Wales being limited by the thermal capacity of the Eildon – Thomastown 220 kV line (VNI #7).[274] The constraint corresponds to:

- The augmentation driver of increased import from New South Wales to Victoria at times of high demand periods coinciding with high ambient temperature in the 2018 ISP.[275]
- Transmission limitations on the Eildon – Thomastown 220 kV line in the 2016 NTNDP.[276]

AEMO and TransGrid did not discuss solutions to address this constraint in their PSCR. AEMO did propose three solutions to address this expected constraint in their 2018 VAPR. The VAPR indicated that project selection is yet to be determined. AEMO is currently investigating

267 AEMO, *Victorian Annual Planning Report 2018*, July 2018, p. 29.

268 AEMO and TransGrid, *Victoria to New South Wales Interconnector Upgrade - Regulatory Investment Test for Transmission Project Specification Consultation Report*, November 2018, pp. 8-10.

269 Correspondence with AEMO on 7 September 2018.

270 AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 74.

271 AEMO, *Victorian Annual Planning Report 2018*, July 2018, p. 47.

272 ibid, p. 5; p. 30.

273 ibid, p. 30; p. 47.

274 Correspondence with AEMO on 7 September 2018.

275 AEMO, *ISP Appendices,* Appendix D.3.5, July 2018, p. 74.

276 AEMO, *National Transmission Network Development Plan*, December 2016, p. 42.

options such as these to increase import capacity from New South Wales to Victoria.[277] The three solutions proposed are:[278]

- Installing a wind monitoring scheme. AEMO did not provide an indicative cost for this project in the 2018 VAPR.
- Implement a load-shedding scheme to allow for operating the line to a higher thermal rating. AEMO did not provide an indicative cost for this project in the 2018 VAPR.
- Uprating the Eildon – Thomastown 220 kV line, including terminations up to 75°C operation. This proposal has an estimated cost of $44.6 million.

The sixth expected constraint in the Victorian transmission network involves Victorian limitations on the Dederang to Mount Beauty 220kV lines (VNI #8).[279] While this constraint was identified in the 2016 NTNDP, AEMO did not identify it as a constraint in the 2018 ISP.[280]

AEMO and TransGrid did not discuss solutions to address this constraint in their PSCR. AEMO did propose two solutions to address this expected constraint in their 2018 VAPR. The VAPR indicated that project selection is yet to be determined and did not provide an indicative timing, noting that AEMO is currently investigating options such as these to increase import capacity from New South Wales to Victoria.[281] The solutions proposed are:[282]

- Installing a wind monitoring scheme. AEMO did not provide an indicative cost for this project in the 2018 VAPR.
- Uprating the conductor temperature of both 220 kV circuits between Dederang and Mount Beauty to 82°C. This proposal has an estimated cost of $12.4 million.

Several of these potential upgrades to VNI are recommended by AEMO for immediate investment in the suite of Group 1 projects proposed in the 2018 ISP.[283]

The VNI upgrades that AEMO recommends as 2018 ISP Group 1 projects comprise:[284]

- A braking resistor at Loy Yang or Hazelwood 500 kV, battery storage or FACTS device to increase transient stability.
- An additional new 500/330 kV transformer at South Morang.
- Uprate the South Morang - Dederang 330 kV and series capacitor.
- Uprate the Upper Tumut - Canberra 330 kV line.

Table 6.2 shows the linkages between 2018 ISP projects and the projects proposed by TNSPs in their transmission planning documents.

277 AEMO, *Victorian Annual Planning Report 2018*, July 2018, p. 5; p. 30.

278 ibid, p. 30; p. 47.

279 AEMO, *National Transmission Network Development Plan*, December 2016, p. 42.

280 AEMO has clarified to the AEMC that the proposed Victorian to New South Wales upgrade outlined in Appendix D.1.2 of the ISP would address this constraint. See AEMO, Letter - Last Resort Planning Power (LRPP) request for information - expected inter-regional constraints, 27 November 2018. See also AEMO, *ISP Appendices*, July 2018, pp. 61-63.

281 AEMO, *Victorian Annual Planning Report 2018*, July 2018, p. 5; p. 30.

282 ibid, p. 30; p. 47.

283 AEMO, *Integrated System Plan*, July 2018, pp. 7-8. The details of the Group 1 projects are listed as Phase 1 projects in AEMO, *ISP Appendices*, *D.1.* July 2018, p. 61, with additional information regarding these projects in AEMO, *ISP Appendices*, *D.3.,* July 2018, p. 69.

284 AEMO, *ISP Appendices*, July 2018, p. 61.

Table 6.2: **Identified VIC - NSW constraints and proposed solutions - VNI**

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in 2016 NTNDP, 2018 ISP and AEMO Correspondence	VNI#1: Victorian exports to New South Wales limited by transmission limitations on the Sydney to Canberra/Yass 330 kV corridor during times with increased generation in southern New South Wales and high export from Victoria to New South Wales	Several projects being considered, including: • Uprating the existing Canberra – Upper Tumut 330 kV line (PSCR Options 1, 2, 3) • Uprating existing 330 kV lines between Snowy and Sydney, and Canberra – Upper Tumut (PSCR Options 2, 3) • Additional 500 kV single circuit line between Snowy and Bannaby, bringing forward part of a Group 2 project in the ISP. This is an alternative to uprating existing 330 kV lines between Snowy and Sydney (PSCR Options 2a and 3a)	Proposed by AEMO and TransGrid	Estimated costs and lead time are: • $28 million and 27 months to uprate Canberra - Upper Tumut line • $36-112 million and 44-63 months for uprating selected existing 330 kV lines between Snowy and Sydney • $520 million and 47 months for bringing forward a new 500 kV line between Snowy and Bannaby.	Uprating the Canberra-Upper Tumut line is a Group 1 project
Identified in 2016 NTNDP, 2018 ISP and AEMO Correspondence	VNI#2: Flows towards New South Wales are limited by the thermal capacity of the Upper Tumut - Canberra 330 kV line				
Identified in 2016 NTNDP, 2018 ISP and	VNI#3: Transmission limitation	Several projects being considered, including:	Proposed by AEMO and	Estimated costs and lead time are:	An additional new transformer

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
AEMO Correspondence	on South Morang 500/330kV transformer	• Additional 500/330 kV transformer(s) at South Morang (PSCR Options 1, 2, 3) • Replacing the existing South Morang transformer with a transformer that has higher capacity (PSCR Options 1, 2, 3)	TransGrid	• $29 million and 36 months for a new 500/ 330 kV transformer • Cost and timing unspecified for replacing the transformer Project selection to be determined.	is a Group 1 project
Identified in 2016 NTNDP, 2018 ISP and AEMO Correspondence	VNI#4: Transmission limitations on Dederang - South Morang 330 kV circuits	Several projects being considered, including: • Uprating the South Morang - Dederang 330 kV lines by conductor re-tensioning and associated works (including uprating of series capacitors) to allow the line to run to thermal rating (PSCR Options 1, 2) • Replacing the existing 330 kV South Morang - Dederang lines with higher capacity conductors (PSCR Option 3)	Proposed by AEMO and TransGrid	Estimated costs and lead time are: • $17 million and 30 months for re-tensioning the existing lines and associated works to allow the line to run to thermal rating • Cost and timing to be determined for replacing the existing lines, depending on associated works	Uprating the South Morang-Dederang lines is a Group 1 project

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
		• A new circuit line (with series compensation) in parallel with the existing South Morang - Dederang 330 kV lines (PSCR Option 3b)		• $370 million and 60 months for a new circuit line (with series compensation) parallel to the existing lines Project selection to be determined.	
Identified in 2018 ISP and AEMO Correspondence	VNI#5: Flows towards New South Wales are limited by the transient stability limit for a 2 phase to ground fault on a South Morang - Hazelwood 500 kV line	Several projects being considered, including: • Installing a braking resistor (PSCR Options 1, 2, 3) • Installing a synchronous condenser with inertia support (PSCR Option 1a) • Installing an SVC (PSCR Option 1b) • Installing batteries with fast response inverters (PSCR Option 1c)	Proposed by AEMO and TransGrid	Estimated costs and lead time are: • $13 million and 24 months for braking resistor. • $20 million and 30 months for synchronous condenser with inertia support. • $19 million and 30 months for SVC • Costs to be determined and 24 months for batteries with inverters. Project selection to be determined.	A braking resistor, battery storage or a FACTS device are AEMO Group 1 projects

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in 2016 NTNDP, 2018 ISP and AEMO Correspondence	VNI#6: New South Wales to Victoria import is limited by thermal capacity of the Murray - Dederang 330 kV line	Several projects being considered, including: • Installing a third 330 kV, 1,060 MVA single circuit line between Murray and Dederang • Implement a load-shedding scheme to allow for operating the line to a higher thermal rating • Installing a second 330 kV line from Dederang to Jindera	Proposed by AEMO	A 3rd Murray - Dederang line has an estimated cost of $183.9 million (excluding easement costs) A 2nd Dederang – Jindera line has an estimated cost of $152 million (excluding easement costs) Project selection to be determined. Project timing is unclear.	No
Identified in 2018 ISP and AEMO Correspondence	VNI#7: New South Wales to Victoria import is limited by thermal capacity of the Eildon - Thomastown 220 kV line	Several projects being considered, including: • Installing a wind monitoring scheme • Implement a load-shedding scheme to allow for operating the line to a higher thermal rating • Up-rate the Eildon – Thomastown 220 kV line, including terminations to 75ºC operation	Proposed by AEMO	Uprating the line has an estimated cost of $44.6 million. Project selection to be determined. Project timing is unclear.	No

RELEVANT AEMO REPORTS	CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in 2016 NTNDP	VNI#8: Transmission limitations on Dederang – Mt. Beauty 220 kV lines	Several projects being considered, including: • Installing a wind monitoring scheme • Up-rating the conductor temperature of both 220 kV circuits between Dederang and Mount Beauty to 82 ºC	Proposed by AEMO	$12.4 million for uprating the conductor temperature Project selection to be determined. Project timing is unclear.	No

6.3.4 Conclusion: VNI

In summary, all identified inter-regional constraints associated with VNI are being considered by the relevant TNSP. AEMO identified eight expected inter-regional constraints on VNI. AEMO and TransGrid are proposing several options to augment VNI, with many comprising a suite of projects. The expected constraints are addressed by these various options and projects.

6.4 The proposed Snowylink interconnector

In addition to the expected constraints and associated solutions discussed above, AEMO's 2018 ISP and the transmission annual planning reports of both TransGrid and AEMO discuss the proposal of a new interconnector connecting New South Wales with Victoria.

The Snowylink proposal has two components:

- SnowyLink North would connect the Snowy 2.0 project to Sydney, which would involve a new link from Tumut to Bannaby and associated works between Bannaby and Sydney West.[285] This project is classified as a Group 2 project in the 2018 ISP.[286] According to the 2018 ISP, Snowylink North would entail:[287]
  - 1x 500 kV single circuit between Wagga and Bannaby and 1x 500/330 kV transformer at Wagga
  - Establishing a new substation in Snowy (cut-in Upper Tumut – Lower Tumut 330 kV line - #64 and establish a substation for Snowy 2.0 connection) with 500/330 kV transformers
  - 1x500 kV line between Snowy 2.0 and Bannaby
  - 1x500 kV line between Snowy 2.0 and Wagga
  - 2x500 kV circuits between Darlington Point and Wagga (coordinated with the RiverLink option)[288]
  - Power flow controller on the Bannaby - Sydney West 330 kV line (Line #39) to limit power flow
  - 1x500/330 kV transformer at Bannaby (third).
- Snowylink South would connect the Snowy 2.0 project to Melbourne via a central Victorian path. AEMO also considers that net market benefits would support increased interconnection capacity in the southern sections to Victoria from 2035, or earlier if Yallourn Power Station retires.[289] This project is classified as a Group 3 project in the 2018 ISP and would entail:[290]

285 AEMO, *Integrated System Plan*, July 2018, p. 9.
286 Additional details regarding the individual projects can be found in AEMO, *ISP Appendices*, July 2018, p. 69.
287 ibid.
288 See Chapter 7 for details on the proposed interconnector. RiverLink is now called Project EnergyConnect.
289 AEMO, *ISP Appendices*, July 2018, p. 63.
290 Additional details regarding the individual projects can be found in AEMO, *ISP Appendices*, July 2018, p. 74.

- 2x500 kV new circuits between Ballarat and Sydenham
- 2x500/220 kV transformers at Ballarat
- 2x500 kV new circuits between Ballarat and Bendigo
- 2x500 kV new circuits between Kerang and Bendigo
- 2x500 kV new circuits between Kerang and Darlington Point
- 2x500/220 kV transformers at Ballarat, Bendigo and Kerang
- A power flow controller on the Bendigo - Shepparton 220 kV line to limit power flow on this line to its maximum thermal capacity (if necessary).
- Power flow controller on the Murray-Dederang and Wodonga-Dederang 330 kV lines to limit power flow on these lines to their maximum thermal capacity (if necessary).

AEMO expects the proposed Snowylink development to increase the Victoria to New South Wales transfer capability by 2,100 MW towards New South Wales and 1,800 MW towards Victoria. The approximate cost of this proposed interconnector is $2.7 billion.[291]

291 ibid, pp. 61-62.

7 REVIEW OF VICTORIA - SOUTH AUSTRALIA CONGESTION

BOX 7: SUMMARY OF FINDINGS

All transmission network inter-regional constraints expected to affect flows between Victoria and South Australia are being addressed by the relevant TNSPs in their transmission annual planning reports. This includes all inter-regional constraints relevant to the Heywood and Murraylink interconnectors. 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 chapter provides the Commission's analysis of whether there are any significant inter-regional constraints affecting the flows between Victoria and South Australia that are not being addressed by the relevant TNSPs. The chapter:

- Describes the Heywood and Murraylink interconnectors.
- Reviews inter-regional constraints between Victoria and South Australia by examining:
  - The constraints expected to affect these interconnectors into the future based on an examination of AEMO's 2018 ISP, the 2016 NTNDP and additional written advice provided by AEMO to the AEMC.
  - The binding constraint equations that had the highest market impact in 2017 (from AEMO's 2018 NEM constraint data).
- Reviews ElectraNet and AEMO's 2018 TAPRs, and the South Australia Energy Transformation RIT-T PADR regarding projects that address inter-regional constraints affecting the Heywood and Murraylink interconnectors.[292]
- Compares the projects that ElectraNet and AEMO identify in these reports with AEMO's expected inter-regional constraints to identify if there are any 'gaps' where a TNSP has not responded to an expected inter-regional constraint identified by AEMO.

7.1 Introduction

7.1.1 Historical flows between Victoria and South Australia

Figure 7.1 presents the annual flows of electricity between Victoria and South Australia over the last ten financial years.[293] The negative flows indicate Victorian imports and the positive flows indicate Victorian exports. The chart shows:

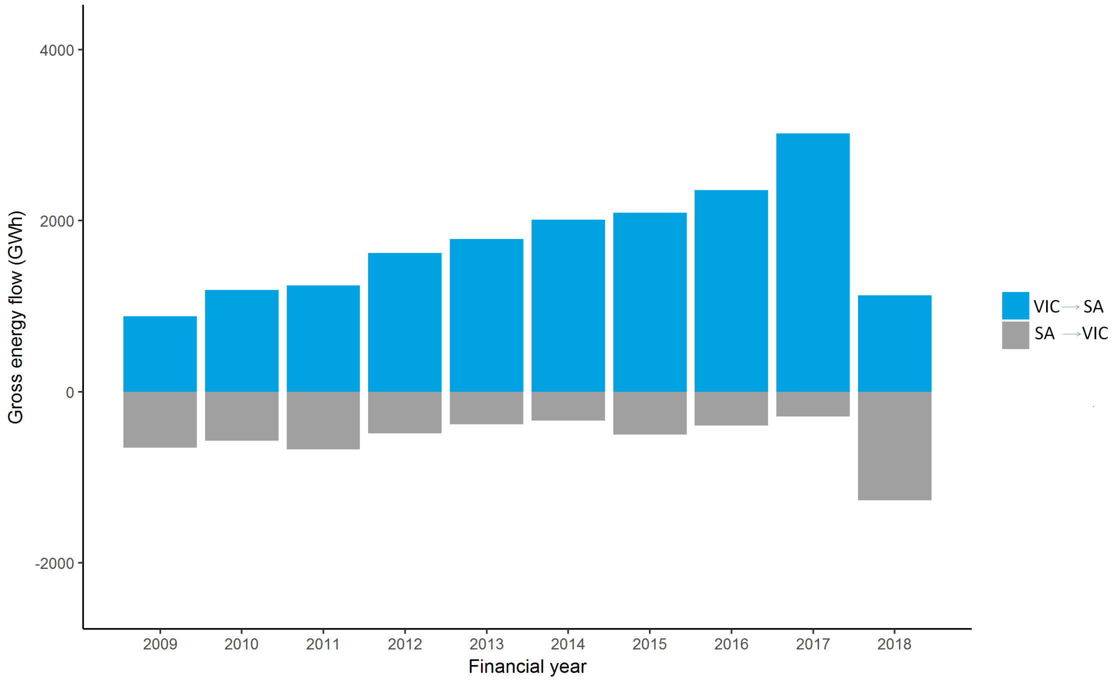
- Victorian exports to South Australia increased progressively before falling in 2018.

292 ElectraNet, *SA Energy Transformation RIT-T Project Assessment Draft Report,* June 2018.

293 This chart includes all constraints binding the Heywood and Murraylink interconnectors, including any system normal or outage constraints. The financial year as reported in the chart encompasses the first half of that year and the second half of the previous year; i.e. 2018 represents the 2017/18 financial year.

- Flows from South Australia to Victoria were much smaller than flows in the other direction until 2018. In 2018, flows from South Australia to Victoria increased significantly, and became slightly larger than flows in the other direction.

Figure 7.1: Inter-regional flows between Victoria and South Australia (2009 - 2018)



Two interconnectors transport electricity in the NEM between Victoria and South Australia; the Heywood interconnector and Murraylink interconnector.

7.1.2 The Heywood interconnector

The Heywood interconnector is an alternating current connection between Heywood in Victoria and the south-east of South Australia.[294] It is defined as the flow across the 275 kV lines between the Heywood substation in Victoria and the South East substation in South Australia.[295]

ElectraNet has recently carried out upgrades on the Heywood interconnector to increase the interconnector's nominal transfer capacity to 650 MW in either direction of flow.[296] AEMO has carried out tests to progressively release the increased capacity into the market. The limits on the Heywood interconnector currently remain below 650 MW in order to manage system security issues, including a potential stability issue at high levels of transfer from Victoria to

294 AEMO, *NEM Constraint Report 2016,* June 2017, pp. 28-29.
295 AEMO, *Interconnector Capabilities,* November 2017, p. 6.
296 ibid.

South Australia.[297] The AEMC understands that AEMO is exploring methods such as setting up special protection systems in order to incrementally and securely release further capability towards the intended 650 MW. As a result, the Heywood interconnector currently has a nominal capacity of:[298]

- 600 MW from Victoria to South Australia
- 500 MW from South Australia to Victoria.

The Heywood interconnector now includes three 500/275 kV transformers at Heywood and connects into South Australia via a double circuit 275 kV line.[299] It also includes a number of connections to the parallel 132 kV network in south-eastern South Australia.[300]

In terms of recent flows on the Heywood interconnector, Figure 7.2 shows all flows during the 2016-2017 financial year and Figure 7.3 shows all flows during the 2017-2018 financial year.[301] Flows from Victoria to South Australia are shown as positive, and flows from South Australia to Victoria appear as negative. The chart also shows (in purple) when inter-regional constraints have limited the flows on the interconnector below its maximum capacity (i.e. constraints have 'bound') in each direction.[302] While constraints generally bind below a certain 'maximum' level, sometimes constraints can bind to prevent the flows from falling below a 'minimum' level.

297 ibid, p. 6. See also AEMO 2017, Update Inter-Network Testing and Transfer Limit - Heywood Interconnector, viewed 15 October 2018, http://www.aemo.com.au/Market-Notices?currentFilter=&sortOrder=searchString =56893

298 AEMO, *Interconnector Capabilities,* November 2017, p. 6.

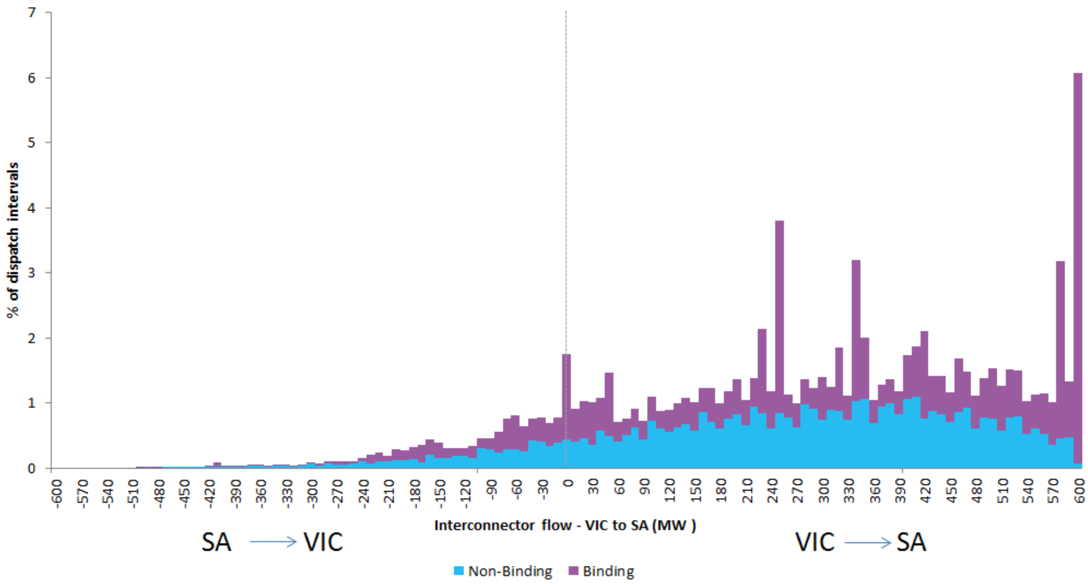
299 ibid.

300 ibid.

301 These charts include all constraints binding the Heywood interconnector, including any system normal or outage constraints.

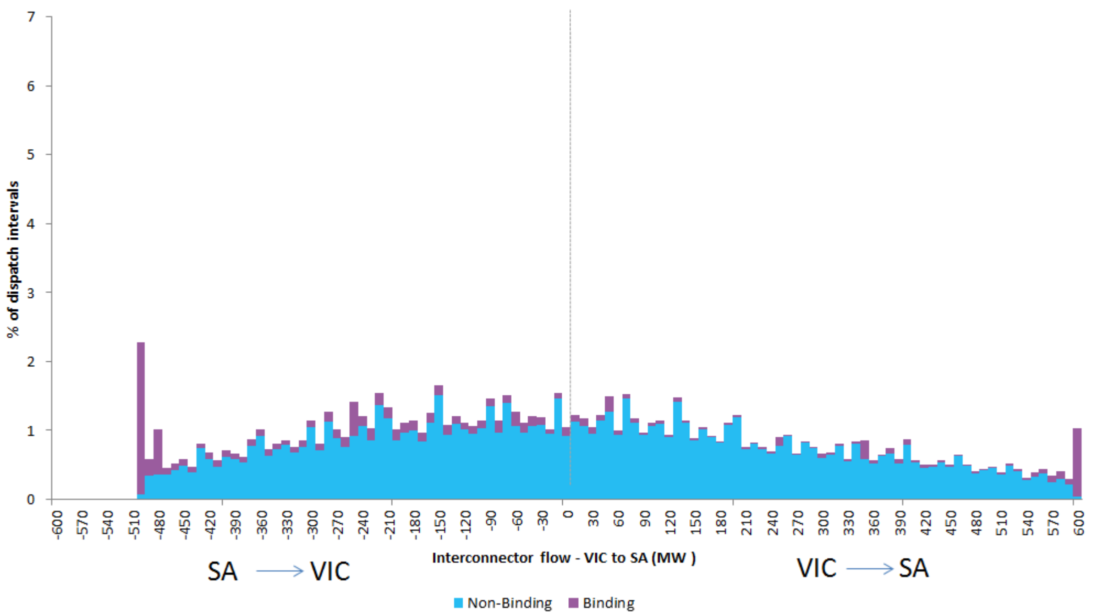
302 A constraint is said to be 'binding' when AEMO cannot dispatch the lowest bid priced generation because of network constraints. A constraint is said to be an inter-regional constraint if it impacts on flows between NEM regions. That is, if the constraint limits flows on an interconnector (see Chapter 3, section 3.2.2).

Figure 7.2: Inter-regional flows via the Heywood interconnector (2016 - 2017)



Source: AEMC analysis of Neopoint database.
Note: This figure covers financial years.

Figure 7.3: Inter-regional flows via the Heywood interconnector (2017 - 2018)



Source: AEMC analysis of Neopoint database.
Note: This figure covers financial years.

These charts indicate a trend of increasing flows from South Australia to Victoria through the Heywood interconnector. In 2016-17, the Heywood interconnector predominantly transmitted energy from Victoria to South Australia, but in 2017-18, energy flowed more equally in both directions.

In addition, they show that there was a significant overall reduction in occurrences of the Heywood interconnector being bound by constraints in 2017-18. The interconnector bound much less often at its nominal maximum Victorian export capacity of 600 MW than it did in 2016-2017. However, it bound more often at its nominal maximum Victorian import capacity of 500 MW than it did in 2016-2017.

7.1.3 The Murraylink interconnector

Murraylink is a HVDC link that connects Red Cliff in Victoria to Berri in South Australia.[303] The Murraylink interconnector currently has a nominal capacity of:

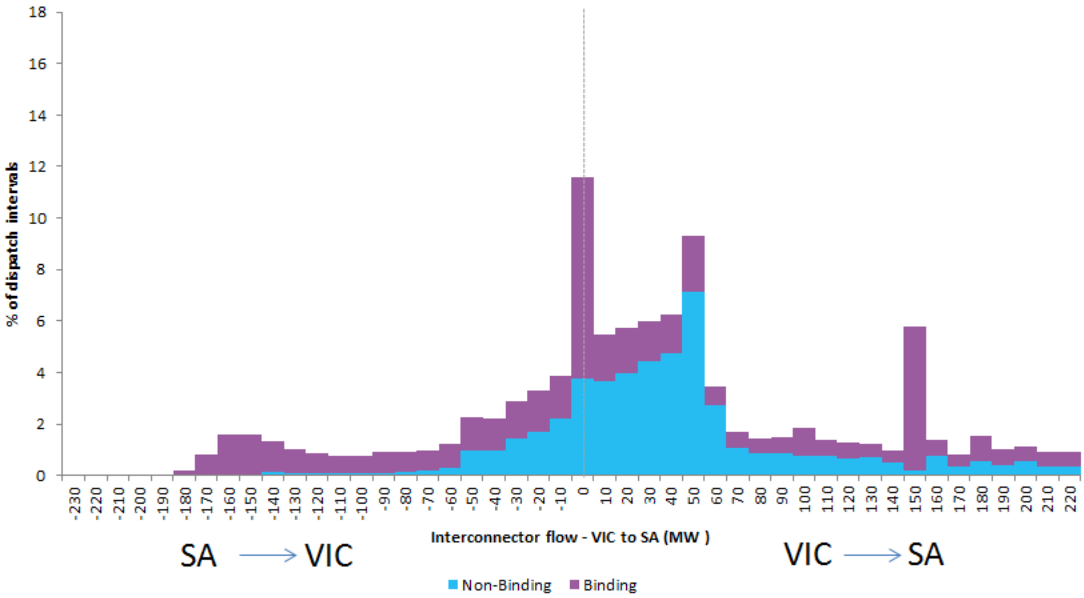
- 220 MW from Victoria to South Australia
- 200 MW from South Australia to Victoria.[304]

303 ElectraNet, *South Australian Transmission annual planning report*, June 2017, p. 104.
304 AEMO, *Interconnector Capabilities*, November 2017, p. 7.

Murraylink features runback schemes that manage many of the thermal issues in the Riverland of South Australia and western Victoria 220kV.[305]

Figure 7.4 shows all flows in both directions on the Murraylink interconnector during the 2016-2017 financial year and Figure 7.5 shows all flows in both directions on the Murraylink interconnector during the 2017-2018 financial year.[306] Flows from Victoria to South Australia are shown as positive, and those from South Australia to Victoria appear as negative. The chart also shows (in purple) when inter-regional constraints have limited the flows on the interconnector below its maximum capacity (i.e. constraints have 'bound') in each direction.

Figure 7.4: Inter-regional flows via the Murraylink interconnector (2016 - 2017)

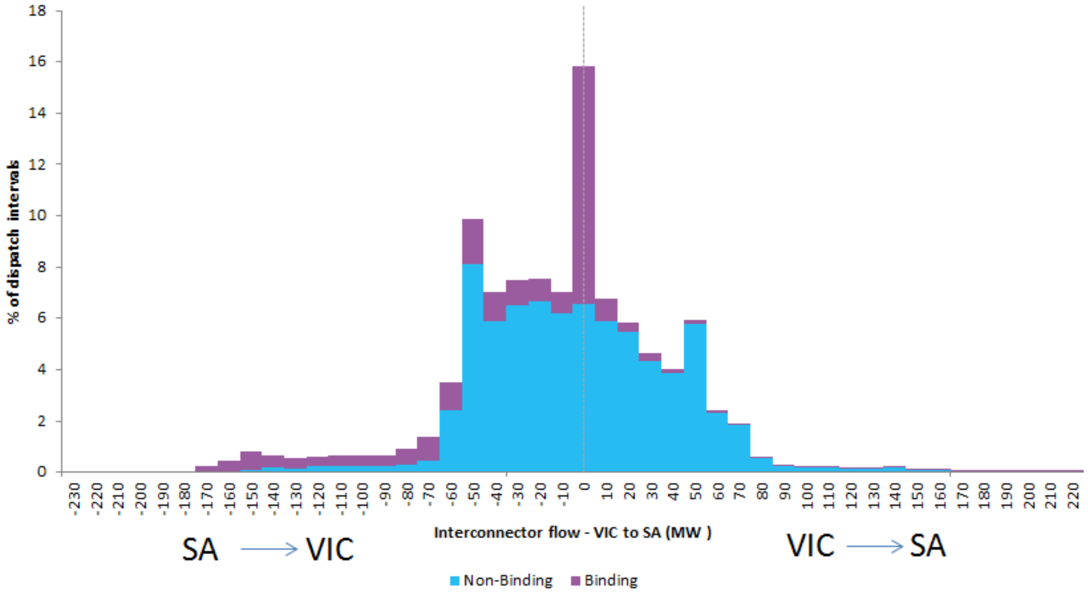


Source: AEMC analysis of Neopoint database.
Note: This figure covers financial years.

305 ibid. Special protection schemes detect and respond to contingency events so the power system remains in a satisfactory operating state. A runback scheme is a type of special protection scheme which reduces the flow of electricity in a given network element in a controlled way, in response to a specific event. See AEMO, *Summer operations 2017-18*, November 2017, p. 19.

306 These charts include all constraints binding the Murraylink interconnector, including any system normal or outage constraints.

Figure 7.5: Inter-regional flows via the Murraylink interconnector (2017 - 2018)



Source: AEMC analysis of Neopoint database.
Note: This figure covers financial years.

These charts indicate a trend of more frequent flows from South Australia to Victoria through the Murraylink interconnector. In 2016-17 the Murraylink interconnector predominantly transferred energy from Victoria to South Australia. In 2017-18 energy flowed more equally in both directions.

In 2017-18, the interconnector bound less often for both positive and negative flows than in 2016-17, but bound more often at a flow of 0 MW in either direction. The AEMC understands that the majority of time that the Murraylink interconnector was constrained to 0 MW in either year was likely due to being out of service for maintenance or due to a forced outage.

7.2 Current inter-regional constraints affecting Victoria – South Australia flows

This section outlines the major binding inter-regional constraints that currently affect Victoria – South Australia flows (in both directions). It examines binding constraints in terms of their total market impact, with a focus on system normal constraints.[307] The information and analysis in this section is based on AEMO data on constraint equation performance for the 2017 calendar year.[308]

307 See Chapter 3, section 3.2.5 for an explanation of 'market impact' and how it is calculated. System normal constraints do not include constraints caused by outages of transmission elements.

308 AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

In 2017 the total market impact of inter-regional system normal constraints was higher for electricity flows from Victoria to South Australia than for flows in the other direction.[309] The market impact of inter-regional system normal constraints was lower in both directions in 2017 than during the previous year.[310]

Six of the top ten (by total market impact) inter-regional binding system normal constraints for all the interconnectors in the NEM are associated with flows between South Australia and Victoria.[311] Table 7.1 shows that:

- All of the binding constraints with substantial market impacts involved exports from Victoria to South Australia.
- The market impact of three out of the six constraints has increased, and the market impact of the other three constraints has decreased.
- Two of the six major constraints bound both the Heywood interconnector and the Murraylink interconnector. These constraints are indicated in the table as #8b and #8d, as well as #10c and #10d.
- Some of the major constraints that bound Victoria – South Australia flows in 2017 also limited flows on other interconnectors which link Victoria to other states (such as VNI).[312] It follows that multiple interconnectors can be constrained by the same transmission network limitation(s).

309 Analysis based on figures from AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

310 ibid.

311 Listed in Chapter 3, section 3.2.5, Table 3.2. Additional detail regarding the listed constraints is also located in AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

312 See Table 3.2 in Chapter 3, section 3.2.5.

Table 7.1: **Current major inter-regional system normal constraints affecting Victoria - South Australia**

2017 NEM MARKET IMPACT RANKING AND AEMO EQUATION ID[1]	MARKET IMPACT ($2017)[2]		DESCRIPTION[3]	HOURS BINDING		FLOW DIRECTION
	2017	2016		2017	2016	
2b N^^V_NIL_1 Voltage stability	736,588	43,476	This constraint manages voltage stability, which is used for managing transmission voltages so that they remain at acceptable levels if a credible contingency occurs. The relevant contingency event is the loss of the largest Victorian generating unit or the Basslink interconnector.	1,343	69	Murraylink Victoria export
3 V:S_600_HY_TEST_DYN Oscillatory stability	582,677	78,448	The constraint is used as the upper limit for the Heywood interconnector to manage oscillatory stability. It limits network flows to ensure the dampening of power system oscillations is adequate following a credible contingency.	98	76	Heywood Victoria export
5 V^SML_NSWRB_2 Voltage stability	441,280	531,291	This constraint is used to manage voltage stability in the case of an electricity supply interruption of a 220 kV line from Darlington Point, NSW to Buronga, NSW, when the Murraylink runback scheme is enabled.	53	154	Murraylink Victoria export

2017 NEM MARKET IMPACT RANKING AND AEMO EQUATION ID[1]	MARKET IMPACT ($2017)[2]		DESCRIPTION[3]	HOURS BINDING		FLOW DIRECTION
	2017	2016		2017	2016	
7a V>>SML_NIL_8 Thermal overload	185,107	82	This is a thermal overload constraint. Thermal overload constraints are used to manage the power flow on a transmission element so that it does not exceed a rating (either continuous or short term) under normal conditions or following a credible contingency. This constraint is used to avoid exceeding the rating of the Ballarat, Victoria to Bendigo, Victoria 220 kV line in the case of an interruption of supply through the Shepparton, Victoria to Bendigo, Victoria 220 kV line.	2	0.3	Murraylink Victoria export
8b V::N_NILxxx Transient stability	181,973	244,494	This constraint is used to maintain transient stability of the Yallourn Power Station in the case of a fault on one of the 500 kV lines from Heywood in Victoria to South East in South Australia.	560	808	Murraylink Victoria export
8d As above				453	575	Heywood Victoria export

2017 NEM MARKET IMPACT RANKING AND AEMO EQUATION ID[1]	MARKET IMPACT ($2017)[2]		DESCRIPTION[3]	HOURS BINDING		FLOW DIRECTION
	2017	2016		2017	2016	
10c V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P Thermal overload	143,897	147,950	This is a thermal overload constraint used to avoid overloading the South Morang 500/330 kV (F2) transformer when there are no contingencies and radial/parallel modes occur involving Yallourn W1 and the 500 or 220 kV lines to which the generator is connected.	294	945	Heywood Victoria import
10d As above				272	879	Murraylink Victoria export

Source: AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

Note: 1 - System normal constraints do not include constraints caused by outages of transmission elements. The table does not include constraints involving FCAS requirements. This table uses calendar years, and the constraints are categorised by market impact. The inter-regional constraints in this table are the constraints relevant to this chapter from the top 10 inter-regional constraints by total market impact for the entire NEM (2017) presented in Table 3.2.

Note: 2 - 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 over a year to provide a total marginal market impact. A 2.5 per cent inflation rate is assumed.

Note: 3 - Additional details regarding the listed constraints are located in AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

7.3 Expected inter-regional constraints and TNSP proposed projects

7.3.1 Sources considered

This section examines whether all expected inter-regional constraints affecting flows between Victoria and South Australia are being adequately addressed by the relevant TNSP.

It presents the inter-regional constraints that AEMO in its national transmission planning role expects to affect Victoria – South Australia flows. The sources included in the analysis are AEMO's 2016 NTNDP, the 2018 ISP and the additional written advice AEMO has provided to the AEMC.

The section then identifies projects that ElectraNet and AEMO in its Victorian TNSP role propose in their 2018 annual planning reports to address these expected inter-regional constraints.[313]

It then compares the projects that ElectraNet and AEMO identify in their annual planning reports with AEMO's expected inter-regional constraints, to identify if there are any 'gaps' where a TNSP has not responded to the expected inter-regional constraints that AEMO has identified. The Commission's analysis for the Heywood interconnector is discussed first, followed by analysis of the Murraylink interconnector.

7.3.2 Findings: Heywood interconnector

AEMO has identified one expected inter-regional constraint on the Heywood interconnector in the South Australian transmission network.[314]

This constraint involves voltage limitations on the Tungkillo-Tailem Bend- South East transmission corridor, which restrict flows on the Heywood interconnector (Heywood #1).[315] ElectraNet has proposed four transmission development projects to address this constraint.

The first involves connecting the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo.[316] ElectraNet considers this will alleviate voltage limitations on the Tungkillo-Tailem Bend- South East transmission corridor, addressing associated flow restrictions on the Heywood interconnector and increasing the interconnector's transfer capability by 10 MW.[317] The development would also allow the 650 MW operational limits on the Heywood interconnector

313 The chapter also identifies projects that ElectraNet proposes to assist inter-regional transfers but which do not directly address constraints identified in AEMO's national transmission planning documents.

314 Termed potential limitations in AEMO's 2016 NTNDP.

315 While this constraint was identified in the 2016 NTNDP, AEMO did not identify it as a constraint in the 2018 ISP. AEMO has clarified to the AEMC that the proposed South Australia to New South Wales upgrade discussed in the 2018 ISP is expected to alleviate this constraint. See AEMO, Letter - Last Resort Planning Power (LRPP) request for information - expected inter-regional constraints, 27 November 2018. See also AEMO, *ISP Appendices*, July 2018, pp. 63-65. Additional details can be found in AEMO, *2018 ISP TAPR Project Summary,* July 2018*.* This project summary was released with the 2018 ISP, but contains data collected from 2017 transmission annual planning reports.

316 ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 45; pp. 98-99.

317 ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 98-99. ElectraNet states (p. 99): "Tying in the Tailem Bend to Cherry Gardens 275 kV line is expected to alleviate voltage limitations on the Heywood interconnector, allowing the 650 MW operational limits to be available more often. At times when voltage limits restrict flows on the Heywood interconnector, this project will increase the interconnector's transfer capability by 10 MW." ElectraNet envisages that this project will impact inter-regional transfer.

to be available more often.[318] ElectraNet's timing for this project is June 2021 with an expected cost of $3-6 million.[319] The project is included in ElectraNet's NCIPAP for the 2018-19 to 2022-23 period.[320]

ElectraNet's second proposal involves applying dynamic ratings to transmission lines between South East and Tungkillo.[321] ElectraNet expects this would increase the thermal transfer capacity and reduce congestion of the Heywood interconnector, enabling increased power transfers to and from Victoria by about 31 MW.[322] This proposed project is in ElectraNet's NCIPAP for the 2018-19 to 2022-23 period and is scheduled for June 2019 with an expected cost of less than $5 million.[323]

A third option to address AEMO's expected inter-regional constraint on the Heywood interconnector is to install, connect and commission the spare 160 MVA 275/132 kV transformer as a second transformer on hot standby at Tailem Bend substation.[324] This would resolve constraints on the Heywood interconnector that currently occur during an outage of the existing single 275/132 kV transformer at the Tailem Bend substation.[325] This committed and pending project has a project timing of 2020 and an expected cost of less than $5 million.[326]

ElectraNet's fourth proposal is the construction of a new 'Riverlink' interconnector (now 'Project EnergyConnect') connecting Robertson in South Australia with Darlington Point in New South Wales.[327] The Riverlink proposal would facilitate additional capacity between the South Australian and NSW regions of up to 750 MW in both directions.[328] AEMO and ElectraNet consider that a Riverlink interconnector would also increase flows between Victoria and South Australia, with ElectraNet suggesting that it would provide additional transient stability for the Heywood interconnector.[329]

The proposed Riverlink interconnector is categorised by AEMO as a Group 2 project and is currently under consideration by ElectraNet as part of the South Australian Energy Transformation RIT-T.[330] ElectraNet has published a PADR as part of the RIT-T process, which indicates the draft preferred option to meet the identified need, and was open for

318 ibid.

319 ibid.

320 AEMO, *Comparison of ElectraNet's 2017 TAPR Projects and their Revenue Proposal,* September 2017, p. 10-11.

321 ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 96.

322 ibid.

323 ibid.

324 ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 157.

325 ibid.

326 ibid.

327 ElectraNet, *South Australian transmission annual planning report*, June 2017, pp. 30, 61-62. See also ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 47, AEMO, *National Transmission Network Development Plan*, December 2016, pp. 39, 86-88 and ElectraNet, SA Energy Transformation RIT-T PACR, February 2019. Now 'Project EnergyConnect'.

328 Further details and other drivers for augmentation that are not related to increasing inter-regional flows can be found in AEMO, *ISP Appendices*, July 2018, pp. 63-64.

329 ElectraNet, *SA Energy Transformation RIT-T Project Assessment Draft Report,* June 2018, p. 51. See also AEMO, *ISP Appendices*, July 2018, pp. 63-64. Correspondence with AEMO on 7 September 2018.

330 Project Overview and updates available at: ElectraNet, South Australian Energy Transformation, viewed 10 December 2018, https://www.electranet.com.au/projects/south-australian-energy-transformation/. See also AEMO, *Integrated System Plan*, July 2018, p. 9.

consultation until mid-August 2018.[331] The preferred option C.3i outlined in the PADR includes several key components:[332]

- a new 330 kV double circuit line from Robertstown 330 kV to Buronga 330 kV
- a new 330 kV double circuit line from Buronga to Darlington Point
- a new single circuit 330 kV line from Darlington Point to Wagga Wagga
- two new 275/330 kV transformers at Robertstown
- a new 330/220 kV transformer and four new 330 kV phase shift transformers at Buronga
- 50 per cent series compensation between Robertstown and Buronga (pending further investigation)
- a reactive plant including synchronous condensers, shunt capacitors and shunt reactors at various locations.

The estimated total cost of the proposal is $1.5 billion across both South Australia and New South Wales, with an earliest in-service date of 2022.[333]

ElectraNet has identified several other projects in the South Australian transmission network that would, if implemented, positively impact on inter-regional transfers across the Heywood interconnector. These address inter-regional constraints that were not identified by AEMO in the 2016 NTNDP or 2018 ISP. These projects and the associated constraints are:

- Installing an additional 100 MVAr 275 kV capacitor bank at South East.[334] This project is expected to alleviate expected constraints on the Heywood interconnector due to voltage stability limits.[335] ElectraNet also expects it would increase the 'firmness' of the Heywood interconnector's notional 650 MW capability, which would provide increased availability of its full capability. The project is in ElectraNet's NCIPAP for the 2018-19 to 2022-23 period and has a timing of June 2019 with an expected cost of less than $5 million.[336]
- Turning the Robertstown - Para 275 kV line into Tungkillo substation.[337] This development is expected to resolve transient (rotor angle) and voltage stability limiting the inter-regional transfer capacity of the Heywood interconnector.[338] This proposed project has a project timing of 2024-28 and an expected cost of $4-8 million.[339]

AEMO has not forecast—in its 2016 NTNDP or the 2018 ISP—any inter-regional constraints in the Victorian transmission system impacting flows on the Heywood interconnector.

331 ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 61; p. 167.
332 ElectraNet, *SA Energy Transformation RIT-T Project Assessment Draft Report,* June 2018, p. 59; p. 92.
333 ibid. See also AEMO, *ISP Appendices*, July 2018, pp. 63-64.
334 ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 98.
335 ibid.
336 ibid.
337 ibid, p. 155.
338 ibid.
339 ibid.

Table 7.2: **Identified VIC - SA constraints and proposed solutions - Heywood**

RELEVANT AEMO REPORTS	INTER-REGIONAL CONSTRAINT DETAILS	PROJECT ADDRESSING CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in 2016 NTNDP	Heywood #1: 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	Connect the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo	Proposed by ElectraNet	An indicative cost of $3 - $6 million Indicative project timing is June 2021	No
		Applying dynamic ratings to transmission lines between South East and Tungkillo	Proposed by ElectraNet	An indicative cost of less than $5 million Indicative project timing is June 2019	No
		Installing, connecting and commissioning the spare 160 MVA 275/132 kV transformer as a second transformer on hot standby at Tailem Bend substation	Committed and pending by ElectraNet	An indicative cost of less than $5 million Indicative project timing is during 2020	No
		A new high capacity interconnector (Riverlink) between South Australia and New South Wales	Proposed by ElectraNet	An indicative cost of $1.5 billion Indicative project timing is 2022-2024	No

7.3.3 Conclusion: Heywood interconnector

In summary, all identified inter-regional constraints associated with the Heywood interconnector are being considered by the relevant TNSP (see Table 7.2). AEMO identified one expected inter-regional constraint on the Heywood interconnector. ElectraNet is proposing four potential projects to augment the Heywood interconnector. The expected constraints are addressed by these various projects.

7.3.4 Findings: Murraylink interconnector

AEMO has identified one expected inter-regional constraint on the Murraylink interconnector in the South Australian transmission network.[340] For the Northern South Australian zone, AEMO reported potential limitations on the 132 kV lines in the Riverland region that connect to the Murraylink interconnector (Murraylink #1).[341] The significant dispatch scenario is during high levels of wind and/or solar generation in that zone and high levels of Murraylink export to Victoria.[342]

ElectraNet has proposed three solutions in order to address this constraint, and has recently completed the first. ElectraNet has uprated the Robertstown to North West Bend No. 2 132 kV line and the North West Bend to Monash 132 kV line from 80°C design clearances to 100°C design clearances.[343] This is to resolve transmission limitations on the 132 kV lines in the Riverland region that connect to the Murraylink interconnector.[344] The assets have been in service since August 2018.[345]

ElectraNet's second proposed solution is installing new transformer management relays and bushing monitoring add-on equipment and applying short term ratings to the two 275/132 kV transformers at Robertstown.[346] The proposal is intended to address the thermal design ratings of the Robertstown 275/132 kV transformers, which limit transfer capability across the Murraylink interconnector.[347] The project is in ElectraNet's NCIPAP, with a project timing of June 2022 and an expected cost of less than $5 million.[348]

The third proposal is the construction of a new Riverlink interconnector connecting South Australia with New South Wales, discussed previously.[349]

340 Termed potential limitations in AEMO's 2016 NTNDP.

341 AEMO, *National Transmission Network Development Plan*, December 2016, p. 39.

342 ibid. While this constraint was identified in the 2016 NTNDP, AEMO did not identify it as a constraint in the 2018 ISP. AEMO has clarified to the AEMC that details regarding this constraint can be found in AEMO, *2018 ISP TAPR Project Summary, July 2018.* This project summary was released with the 2018 ISP, but contains data collected from 2017 transmission annual planning reports.

343 ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 66; p. 70.

344 AEMO's 2016 NTNDP refers to the limitations on the Riverland 132 kV lines on page 39, while ElectraNet's 2018 TAPR refers to limitations on the same lines as being addressed on pages 66 and 70.

345 ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 66.

346 ibid, p. 99; p. 154.

347 ibid.

348 ibid.

349 AEMO, *National Transmission Network Development Plan*, December 2016, p. 39; pp. 86-88. See also ElectraNet, *South Australian transmission annual planning report*, June 2017, p. 29; pp. 61-62, as well as ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 31.

ElectraNet identified one project that would positively impact on inter-regional flows on the Murraylink interconnector that does not appear to directly address AEMO-identified inter-regional constraints. ElectraNet proposes to redesign and replace the Murraylink control scheme.[350] This is a committed and pending project by ElectraNet, with a project timing of 2019 and an expected cost of less than $5 million.[351]

AEMO has not forecast—in its 2016 NTNDP or the 2018 ISP—any inter-regional constraints in the Victorian transmission system impacting flows on the Murraylink interconnector.

As summarised in Table 7.3, AEMO identified one expected inter-regional constraint on the Murraylink interconnector. ElectraNet completed the uprating of the Riverland lines in August 2018 and is considering two additional projects to address this constraint. At least one of these options and its associated projects is expected to address each of these identified constraints.

350 ElectraNet, *South Australian transmission annual planning report*, June 2018, p. 161.

351 ibid.

Table 7.3: **Identified VIC - SA constraints and proposed solutions - Murraylink**

RELEVANT AEMO REPORTS	INTER-REGIONAL CONSTRAINT DETAILS	PROJECT ADDRESSING CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in 2016 NTNDP	Murraylink #1: Transmission limitations on 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	Uprate the Robertstown to North West Bend No. 2 132 kV line and the North West Bend to Monash 132 kV line from 80°C design clearances to 100°C design clearances	Completed; asset has been in service since August 2018	Less than $5 million	No
		Installing new transformer management relays and bushing monitoring add-on equipment and applying short term ratings to the two 275/132 kV transformers at Robertstown	Proposed by ElectraNet	An indicative cost of less than $5 million Indicative project timing is June 2022	No
		A new high capacity interconnector	Proposed by ElectraNet	An indicative cost of $1.5 billion	No

RELEVANT AEMO REPORTS	INTER-REGIONAL CONSTRAINT DETAILS	PROJECT ADDRESSING CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
		(Riverlink) between South Australia and New South Wales		Indicative project timing is 2022-2024	

7.3.5 Conclusion: Murraylink interconnector

In summary, all identified inter-regional constraints associated with the Murraylink interconnector are being considered by the relevant TNSP. AEMO identified one expected inter-regional constraint on the Heywood interconnector. ElectraNet is proposing three potential projects to augment the Murraylink interconnector. The expected constraints are addressed by these various projects.

8 REVIEW OF TASMANIA - VICTORIA CONGESTION

> **BOX 8: SUMMARY OF FINDINGS**
>
> All transmission network inter-regional constraints forecast to affect flows between Victoria and Tasmania are being addressed by the relevant TNSPs in their transmission annual planning reports. This includes all inter-regional constraints relevant to the Basslink interconnector. 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 chapter provides the Commission's analysis of whether there are any constraints impacting the flows between Victoria and Tasmania that are not being addressed by the relevant TNSPs. The chapter:

- Describes the Basslink interconnector.
- Reviews inter-regional constraints between Victoria and Tasmania by examining the following:
  - The constraints expected to affect this interconnector into the future based on an examination of AEMO's 2018 ISP, the 2016 NTNDP and additional written advice provided by AEMO to the AEMC.
  - The binding constraint equations that had the highest market impact in 2017 (from AEMO's 2018 NEM constraint data).
- Reviews TasNetworks and AEMO's 2018 transmission annual planning reports and the Project Marinus PSCR regarding projects that address inter-regional constraints affecting the Basslink interconnector.[352]
- Compares the projects that TasNetworks and AEMO identify in these reports with AEMO's inter-regional constraint forecasts to identify if there are any 'gaps' where a TNSP has not responded to an expected inter-regional constraint identified by AEMO.

8.1 Introduction

8.1.1 Historical flows between Tasmania and Victoria

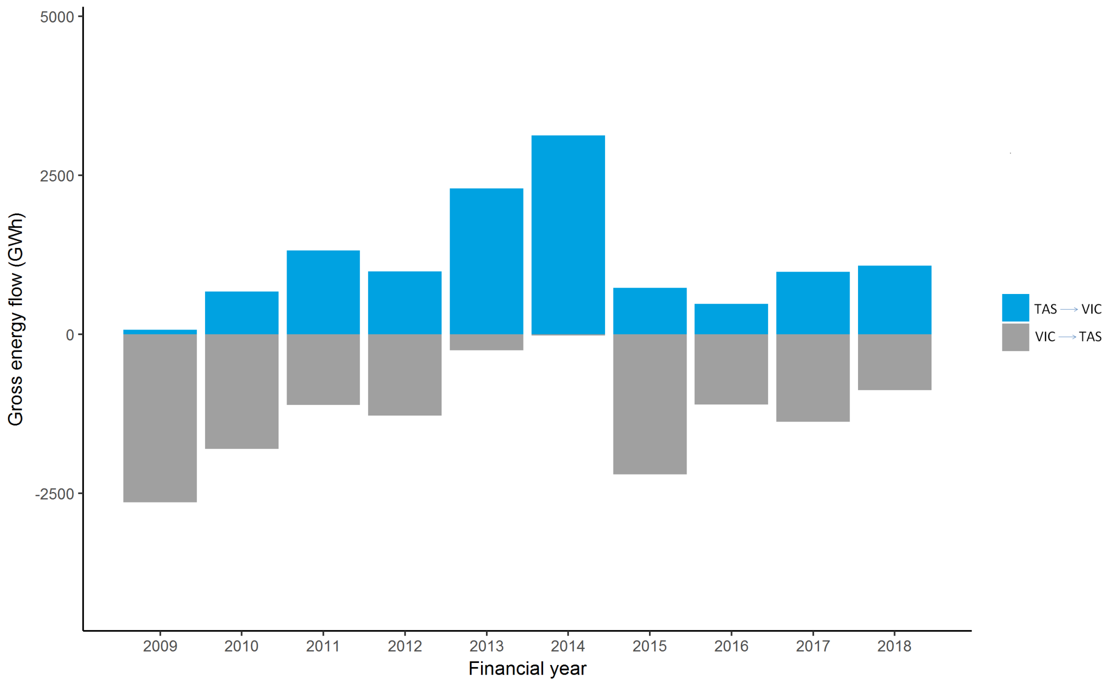
Figure 8.1 presents the annual flows of electricity between Victoria and Tasmania over the last ten financial years.[353] The negative flows indicate Victorian exports and the positive flows indicate Victorian imports. The chart shows:

352 TasNetworks, *Project Marinus Project Specification Consultation Report - Additional interconnection between Victoria and Tasmania*, July 2018.

353 This chart includes all constraints binding the Basslink interconnector, including any system normal or outage constraints. The financial year as reported in the chart encompasses the first half of that year and the second half of the previous year; i.e. 2018 represents the 2017/18 financial year.

- Flows from Tasmania to Victoria experience cycles of increases and decreases over several years, as do flows in the other direction
- While flows on the Basslink interconnector in the last 10 years have been more likely to proceed from Victoria to Tasmania, the Basslink interconnector is less one-sided in the majority of its flows than the other interconnectors in the NEM, with the majority of flows in several recent years also flowing in the other direction.

Figure 8.1: Inter-regional flows between Victoria and Tasmania (2009 - 2018)



One interconnector transports electricity in the NEM between Tasmania and Victoria; the Basslink interconnector.

8.1.2 The Basslink interconnector

The Basslink interconnector is defined as the flow across the DC cable between George Town in Tasmania and Loy Yang in Victoria.[354] While there are no national transmission flow paths in Victoria, the Basslink interconnector is a national transmission flow path, connecting the Tasmania zone with LaTrobe Valley (in Victoria) zone.[355] Unlike the other DC lines in the NEM, the Basslink interconnector has a frequency controller and is able to transfer FCAS between Victoria and Tasmania.

354 AEMO, *Interconnector Capabilities,* November 2017, p. 6.
355 TasNetworks, *Annual Planning Report 2018*, June 2018, p. 73.

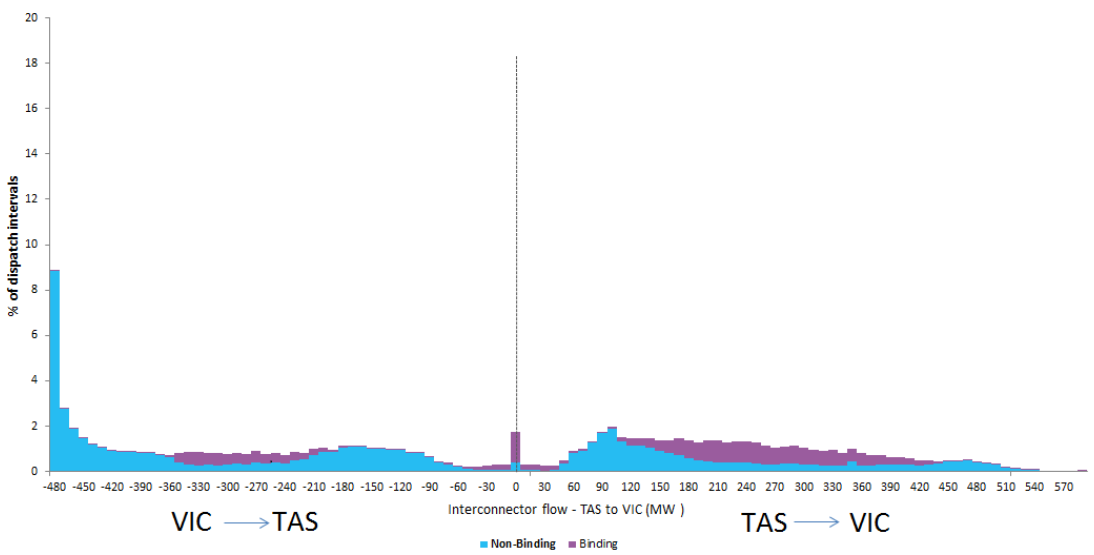
As the Basslink interconnector is an unregulated market interconnector and not a TNSP, RIT-Ts are not required to address an identified investment need on the interconnector. Therefore, if the Commission identified a deficiency in the planning arrangements of the interconnector it would not be able to direct the owners of the Basslink interconnector to carry out a RIT-T under the LRPP. 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.

The Basslink interconnector currently has a nominal capacity of:[356]

- 594 MW from Tasmania to Victoria
- 478 MW from Victoria to Tasmania.

In terms of recent flows on the Basslink interconnector, Figure 8.2 shows all flows during the 2016-2017 financial year and Figure 8.3 shows all flows during the 2017-2018 financial year.[357] Flows from Tasmania to Victoria are shown as positive, and flows from Victoria to Tasmania appear as negative.The chart also shows (in purple) when inter-regional constraints have limited the flows on the interconnector below its maximum capacity (ie constraints have 'bound') in each direction.[358]

Figure 8.2: Inter-regional flows via the Basslink interconnector (2016 - 2017)



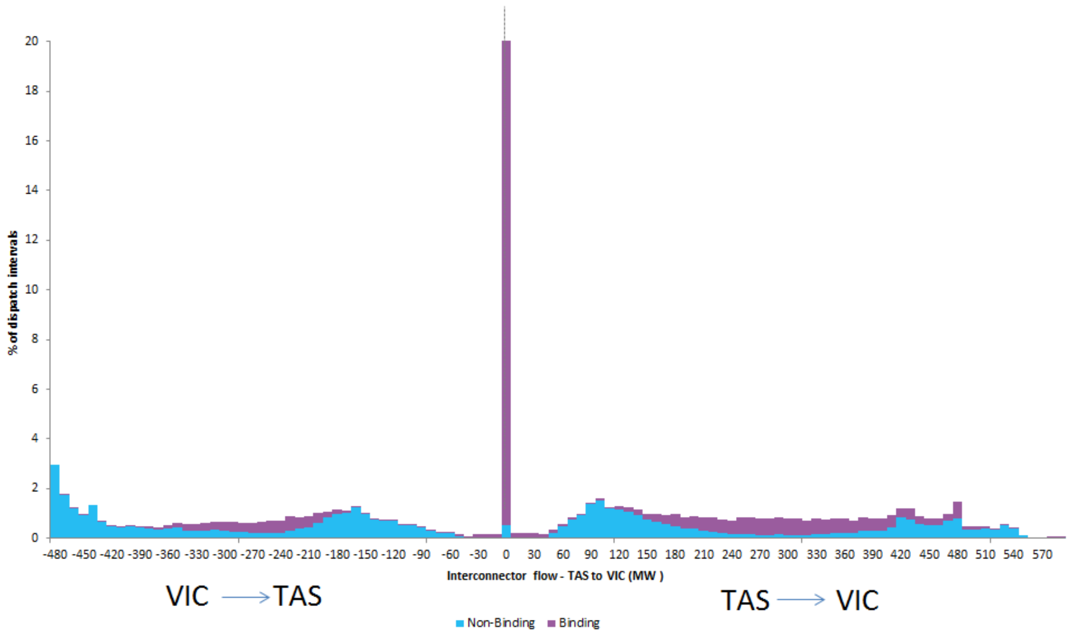
Source: AEMC analysis of Neopoint database.
Note: This figure covers financial years.

356 AEMO, *Interconnector Capabilities,* November 2017, p. 6.

357 These charts include all constraints binding the Basslink interconnector, including any system normal or outage constraints.

358 A constraint is said to be 'binding' when AEMO cannot dispatch the lowest bid priced generation because of network constraints. A constraint is said to be an inter-regional constraint if it impacts on flows between NEM regions. That is, if the constraint limits flows on an interconnector (see Chapter 3, Section 3.2.2).

Figure 8.3: Inter-regional flows via the Basslink interconnector (2017 - 2018)



Source: AEMC analysis of Neopoint database.
Note: This figure covers financial years.

These charts indicate a slight trend of increasing flows from Tasmania to Victoria and a slight trend of decreasing flows from Victoria to Tasmania through the Basslink interconnector.

Unbound flows from Tasmania to Victoria were at high capacity levels slightly more frequently in 2017-18 than in the previous year, even as they remained relatively stable at low capacity levels.Unbound flows from Victoria to Tasmania were slightly less frequent in 2017-18 than in the previous year, both at high and at low flow levels.

Tasmania to Victoria flows bound slightly less often at high flow levels in 2017-18 than in 2016-17. Victoria to Tasmania flows also bound slightly less frequently in 2017-18 than in 2016-17, although this occurred across all flow levels. Flows less commonly approached the maximum nominal capacity in either direction during 2017-18 compared to 2016-17. Notably, the Basslink interconnector bound far more often at 0 MW in 2017-18 than it did in 2016-17. This was likely due to interconnector being out of service during March-April 2018, outages and/or the need to change flow direction, which requires the interconnector to be bound at 0 MW for a short period of time.

8.2 Current inter-regional constraints affecting Tasmania – Victoria flows

This section outlines the major binding inter-regional constraints that currently affect Victoria – Tasmania flows (in both directions). It examines binding constraints in terms of their market impact, with a focus on system normal constraints.[359] The information and analysis in this section is based on AEMO data on constraint equation performance for the 2017 calendar year.[360]

In 2017 the total market impact of inter-regional system normal constraints was higher for electricity flows from Victoria to Tasmania than for flows in the other direction.[361] The market impact of inter-regional system normal constraints was lower from Victoria to Tasmania and higher from Tasmania to Victoria than during the previous year.[362]

Two of the top ten (by market value) inter-regional binding system normal constraints for all the interconnectors in the NEM are associated with flows between Tasmania and Victoria.[363] Table 8.1 shows that:

- Both of the constraints involved Victorian imports from Tasmania.
- The market impact of both constraints decreased in 2017 compared to 2016.
- Both of the major constraints that bound on Tasmania – Victoria flows in 2017 also limited flows on other interconnectors which link Victoria to other states (such as the Heywood interconnector).[364]

359 See Chapter 3, section 3.2.5 for an explanation of 'market impact' and how it is calculated. System normal constraints do not include constraints caused by outages of transmission elements or frequency control ancillary service requirements. This also excludes FCAS constraints.

360 AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

361 Analysis based on figures from AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material,* June 2018.

362 ibid.

363 The top ten constraints are listed in Chapter 3, section 3.2.5, Table 3.2. Additional detail regarding the listed constraints is also located in AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

364 See Table 3.2 in Chapter 3, section 3.2.5.

Table 8.1: **Current major inter-regional system normal constraints affecting Victoria - Tasmania**

EQUATION ID AND CONSTRAINT TYPE[1] (NEM MARKET IMPACT RANKING)	MARKET IMPACT[2] ($2017)		DESCRIPTION[3]	HOURS BINDING		FLOW DIRECTION
	2017	2016		2017	2016	
8c V::N_NILxxx	181,973	244,494	This constraint is used to provide transient stability for Yallourn Power Station in the case of a supply interruption of a 500 kV line from Heywood in Victoria to South East in South Australia.	279	619	Basslink Victoria export
10a V>>V_NIL_2A_R & V>>V_NIL_2B_R & V>>V_NIL_2_P	143,897	147,950	This is a thermal overload constraint used to avoid overloading the South Morang 500/330 kV (F2) transformer when there are no contingencies and radial/parallel modes occur involving Yallourn W1 and the 500 or 220 kV lines that the generator is connected to.	288	814	Basslink Victoria import

Note: 1 - System normal constraints do not include constraints caused by outages of transmission elements. The table does not include constraints involving FCAS requirements. This table uses calendar years, and the constraints are categorised by market impact. The inter-regional constraints in this table are the constraints relevant to this chapter from the top 10 inter-regional constraints by total market impact for the entire NEM (2017) presented in Table 3.2.

Note: 2 - 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 over a year to provide a total marginal market impact. A 2.5 per cent inflation rate is assumed.

Note: 3 - Additional details regarding the listed constraints are located in AEMO, *The National Electricity Market Constraint Report 2017 Electronic Material*, June 2018.

8.3 Expected inter-regional constraints and TNSP proposed projects

8.3.1 Sources considered

This section examines whether all expected inter-regional constraints affecting flows between Tasmania and Victoria are being adequately addressed by the relevant TNSP.

It presents the inter-regional constraints that AEMO in its national transmission planner role expects to affect Tasmania – Victoria flows. The sources included in the analysis are AEMO's 2016 NTNDP, the 2018 ISP and the additional written advice AEMO has provided to the AEMC.

The section then identifies projects that TasNetworks and AEMO in its Victorian TNSP role propose in their 2018 annual planning reports to address these expected inter-regional constraints.[365]

It then compares the projects that TasNetworks and AEMO identify in their annual planning reports with AEMO's expected inter-regional constraints, to identify if there are any 'gaps' where a TNSP has not responded to the expected inter-regional constraints that AEMO has identified.

8.3.2 Findings: Basslink interconnector

AEMO has identified seven expected inter-regional constraints on the Basslink interconnector in the Tasmanian transmission network.[366]

The first expected constraint involves transmission limitations on the Palmerstown to Sheffield 220 kV line during periods of high wind generation from the North West and West Tasmania area, and high Basslink import to Tasmania from Victoria (Basslink #1).[367] TasNetworks' proposed solution to address this expected constraint involves constructing a new Palmerston-Sheffield 220 kV transmission line.[368] The Palmerston-Sheffield line has been included as a contingent project in TasNetworks' revenue submission for the 2019-24 regulatory period and the proposed trigger for this project is currently subject to approval by the AER.[369] The project has an indicative cost of $120 million.[370]

The second expected constraint involves transmission limitations on the George Town to 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 (Basslink #2).[371] TasNetworks is of the view that a second Bass Strait interconnector, if constructed, would

365 The chapter also identifies projects that TasNetworks proposes to assist inter-regional transfers but which do not directly address constraints identified in AEMO's national transmission planning documents.

366 Termed potential limitations in AEMO's 2016 NTNDP.

367 AEMO, *National Transmission Network Development Plan*, December 2016, pp. 39-40. See also AEMO, *ISP Appendices*, July 2018, p. 72.

368 TasNetworks, *Annual Planning Report 2018*, June 2018, p. 74.

369 ibid, p. 68.

370 ibid, p. 67.

371 AEMO, *National Transmission Network Development Plan*, December 2016, pp. 39-40.

relieve this constraint.[372] The funding for a second Bass Strait interconnector has been included as a contingent project in TasNetworks' revenue submission for the 2019-24 regulatory period.[373] TasNetworks's network contribution is assumed to be 50 per cent of the total $1,100 million required for the project.[374] The project is currently being subjected to the RIT-T process, as TasNetworks with support from the Australian Renewable Energy Agency (ARENA) published a PSCR focusing on additional interconnection between Victoria and Tasmania in July 2018.[375]

The Basslink 2 interconnector (also known as Marinus Link) is not an AEMO Group project, although the project is considered as part of the 2018 ISP. TasNetworks' PSCR identifies two possible options:[376]

- Option 1: A 600 MW monopole HVDC link, including associated AC transmission network augmentation and connection assets.
- Option 2: A 1,200 MW bipolar HVDC link, including associated AC transmission network augmentation and connection assets.

The indicative cost range of Option 1 is $1.4-$1.9 billion and the indicative cost range of Option 2 is $1.9-$2.7 billion, with an earliest commissioning date of 2025.[377]

Prior to the construction of a second Bass Strait interconnector, this constraint will be managed by reducing generation or Basslink export as required.[378]

The third identified constraint involves 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 (Basslink #3).[379] TasNetworks has proposed two solutions to address this expected constraint. The first solution is installing a 40 MVAr capacitor bank at George Town Substation, which has already occurred.[380] The capacitor bank cost $3.1 million and was completed in March 2018.[381] The second solution is to install a +/-50 MVAr static synchronous compensator (STATCOM). The estimated cost of this project is $15.1 million and it is planned to be operational by June 2022.[382] The project will be subject to the RIT-T process.

The fourth identified constraint involves over-voltage at George Town when there is high export from Tasmania to Victoria with no gas powered generation units on line in Tamar

372 TasNetworks, *Annual Planning Report 2018*, June 2018, p. 74.

373 ibid, p. 69.

374 ibid.

375 TasNetworks, *Project Marinus Project Specification Consultation Report - Additional interconnection between Victoria and Tasmania*, July 2018.

376 ibid, p. 40.

377 TasNetworks, *Project Marinus Project Specification Consultation Report - Additional interconnection between Victoria and Tasmania*, July 2018, p. 44.

378 TasNetworks, *Project Marinus Project Specification Consultation Report - Additional interconnection between Victoria and Tasmania*, July 2018, p. 74.

379 AEMO, *National Transmission Network Development Plan*, December 2016, pp. 39-40. See also AEMO, *ISP Appendices*, July 2018, p. 56.

380 TasNetworks, *Annual Planning Report 2018*, June 2018, p. 66, 74.

381 ibid, p. 84.

382 ibid, p. 67.

Valley and reduced number of hydro units in northern Tasmania (Basslink #4).[383] TasNetworks' solutions to address this constraint are the same as the solutions intended to address the third constraint; the completed capacitor bank at George Town Substation and installing a +/-50 MVAr STATCOM.[384]

The fifth identified constraint involves 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 (Basslink #5).[385] TasNetworks has proposed a solution to address this expected constraint, which involves investigating with relevant customers to include frequency control services as part of the proposed STATCOM at George Town Substation.[386]

The sixth identified constraint involves a high rate of change of frequency (RoCoF) 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 (Basslink #6).[387] TasNetworks' solution to address this constraint is the same as the solution intended to address the fifth constraint; investigating with relevant customers to include frequency control services as part of the proposed STATCOM at George Town Substation.[388]

The seventh identified constraint involves a high RoCoF for Tasmania for unavailability of existing FCAS with the retirement of smelters in Tasmania (Basslink #7).[389] TasNetworks, in response to this expected constraint, continues to engage with their major industrial customers and does not anticipate the near-term closure of Tasmanian smelters.[390] TasNetworks acknowledges this potential constraint under this planning scenario.

AEMO has not forecast—in its 2016 NTNDP or the 2018 ISP—any inter-regional constraints in the Victorian transmission system impacting flows on the Basslink interconnector.

383 AEMO, *National Transmission Network Development Plan*, December 2016, pp. 39-40. See also AEMO, *ISP Appendices*, July 2018, p. 56.

384 TasNetworks, *Annual Planning Report 2018*, June 2018, p. 74.

385 AEMO, *National Transmission Network Development Plan*, December 2016, pp. 39-40.

386 TasNetworks, *Annual Planning Report 2018*, June 2018, p. 74.

387 AEMO, *National Transmission Network Development Plan*, December 2016, pp. 39-40.

388 TasNetworks, *Annual Planning Report 2018*, June 2018, p. 74.

389 AEMO, *National Transmission Network Development Plan*, December 2016, pp. 39-40.

390 TasNetworks, *Annual Planning Report 2018*, June 2018, p. 74.

Table 8.2: **Identified TAS - VIC constraints and proposed solutions - Basslink**

RELEVANT AEMO REPORTS	INTER-REGIONAL CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in 2016 NTNDP and 2018 ISP	Basslink #1: Transmission limitations on the Palmerston – Sheffield 220kV line during periods of high wind generation from the North West and West Tasmania area and high Basslink import to Tasmania from Victoria	Constructing a new Palmerston-Sheffield 220 kV transmission line	Proposed by TasNetworks - Palmerston - Sheffield line has been included as a contingent project in TasNetworks' revenue submission for the 2019-24 regulatory period	The project has an indicative cost of $120 million No project timing provided; the proposed trigger for this project is currently subject to approval by the AER	No
Identified in 2016 NTNDP	Basslink #2: Transmission limitations on the George Town to 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	A second Basslink interconnector An interim plan is for generation or Basslink export to be reduced as required	Proposed by TasNetworks - funding for a second Bass Strait interconnector has been included as a contingent project in TasNetworks' revenue submission for the 2019-24 regulatory period	A second Basslink interconnector has an indicative cost of $1100 million. The project is currently subject to the RIT-T process No indicative costs or timing are provided for the interim solution	No
Identified in 2016 NTNDP and 2018 ISP	Basslink #3: Voltage collapse at	Several solutions have been proposed:	The capacitor bank was completed by	The STATCOM has an estimated cost of $15.1	No

RELEVANT AEMO REPORTS	INTER-REGIONAL CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
	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	• installing a 40 MVAr capacitor bank at George Town Substation • installing a +/-50 MVAr STATCOM	TasNetworks in March 2018 The STATCOM has been proposed by TasNetworks	million It is expected to be operational by June 2022	
Identified in 2016 NTNDP and 2018 ISP	Basslink #4: 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				
Identified in 2016 NTNDP	Basslink #5: Basslink inverter commutation instability due to low fault level at George Town	Investigating with relevant customers to include frequency control services as part of the proposed STATCOM at	Proposed by TasNetworks	No cost or indicative timing indicated	No

RELEVANT AEMO REPORTS	INTER-REGIONAL CONSTRAINT DETAILS	PROJECT TO ADDRESS CONSTRAINT	PROJECT STATUS	INDICATIVE COST OF PROPOSED PROJECT AND TIMING	2018 ISP GROUP 1 PROJECT?
Identified in 2016 NTNDP	Basslink #6: High RoCoF 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	George Town Substation			
Identified in 2016 NTNDP	Basslink #7: High RoCoF for Tasmania for unavailability of existing frequency control ancillary services (FCAS) with the retirement of smelters in Tasmania	TasNetworks continues to engage with their major industrial customers and does not anticipate the near-term closure of Tasmanian smelters	Proposed by TasNetworks	No cost or indicative timing indicated	No

8.3.3 Conclusion: Basslink interconnector

In summary, all identified inter-regional constraints associated with the Basslink interconnector are being considered by the relevant TNSP. AEMO identified seven expected inter-regional constraints on the Basslink interconnector. TasNetworks has provided proposals to address each expected constraint.

ABBREVIATIONS

AC	Alternating current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
DC	Direct current
HVAC	High voltage alternating current
HVDC	High voltage direct current
IC	Interconnector
ISP	Integrated System Plan
FCAS	Frequency control ancillary services
LRPP	Last resort planning power
MCE	Ministerial Council on Energy
MVAr	Mega volt amps (reactive)
MW	Megawatts
NCIPAP	Network capability incentive parameter action plan
NEL	National Electricity Law
NEM	National electricity market
NEMDE	National electricity market dispatch engine
NEO	National electricity objective
NER	National electricity rules
NTNDP	National Transmission Network Development Plan
QNI	Queensland–New South Wales interconnector
PADR	Project assessment draft report
PSCR	Project specification consultation report
RoCoF	Rate of change of frequency
RIT-T	Regulatory investment test for transmission
SVC	Static VAR compensator
STATCOM	Static synchronous compensator
TAPR	Transmission annual planning report
TNSP	Transmission network service provider
VAPR	Victorian annual planning report
VNI	Victoria–New South Wales interconnector