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23/11/2018

John Pierce AO
Chairman
Australian Energy Market Commission
Level 6, 201 Elizabeth Street
Sydney NSW 2000

By email: john.pierce@aemc.gov.au

Dear John

Re: Request for information on processes underway regarding potential projects to address inter-regional constraints

I am writing to you in response to your letter dated 21 November 2018 in which you requested further clarification on how TransGrid intends to address inter-regional constraints relating to the Queensland – New South Wales Interconnector (QNI) identified by the Australian Energy Market Operator (AEMO) in its inaugural Integrated System Plan released in July 2018.

TransGrid and Powerlink have been jointly planning and we have commenced the Regulatory Investment Test for Transmission (RIT-T) process to progress the ISP's recommendations to increase transfer capacity between New South Wales and Queensland. That is, to progress and consult on both the Group 1 and Group 2 upgrades identified by AEMO.

Please find attached the Project Specification Consultation Report (PSCR) for *'Expanding NSW-QLD transmission transfer capacity'* which has been published for stakeholder feedback. This document is the first step in the RIT-T process. The PSCR outlines:

> The identified need for this RIT-T which is to increase overall net market benefits in the National Electricity Market through relieving existing and forecast congestion on the transmission network between New South Wales and Queensland.
> Five types of credible options identified by TransGrid and Powerlink to increase transfer capacity between New South Wales and Queensland at this stage of the RIT-T, building on the options identified in the ISP. In addition, combinations of these options will be considered.
> How non-network technologies can contribute to meeting the identified need of relieving existing and forecast congestion on the transmission network between New South Wales and Queensland over the short and medium term. Proponents of non-network options are encouraged to make submissions on any non-network option they believe can address, or contribute to, the identified need.

TransGrid and Powerlink welcome written submissions to the PSCR on or before 22 February 2019. This timing is consistent with RIT-T consultation requirements outlined in the National Electricity Rules.

Submissions are particularly sought on the credible options presented and from potential proponents of non-network options that could meet the technical requirements set out in the PSCR. The information provided in submissions will be used to further develop non-network options for inclusion in the next stage of the RIT-T assessment process.

The next formal stage of this RIT-T will be the publication of a Project Assessment Draft Report (PADR). The PADR will include the full quantitative analysis of both network and non-network options, and is expected to be published during 2019. The timing of publication of this document depends on the time required to address issues raised in submissions to the PSCR.

If you require any further clarification, please contact me on (02) 9284 3715 or caroline.taylor@transgrid.com.au.

Yours sincerely,

Caroline Taylor

Caroline Taylor
Acting Executive Manager Policy & Corporate Affairs

Cc: Merryn York, Chief Executive, Powerlink

Expanding NSW-QLD transmission transfer capacity

Project Specification Consultation Report

November 2018

Executive summary

This RIT-T progresses the Integrated System Plan to expand NSW-QLD transfer capacity

The inaugural Integrated System Plan (ISP), released by the Australian Energy Market Operator (AEMO) in July 2018, recommended two key transmission investments in relation to expanding transfer capacity between New South Wales and Queensland necessary to support the long-term interests of consumers for safe, secure, reliable electricity, at the least cost, across a range of plausible futures.

AEMO differentiated these two investments as being needed over the immediate-term (by around 2020) and over the medium-term (by the mid-2020s), respectively.

Figure E.1 The AEMO ISP recommended two expansions to NSW-QLD transfer capacity

The ISP concluded that by 2020, or as soon as they can be built, market benefits associated with the Group 1 upgrade can be realised due to a reduced need for new gas fired generation in New South Wales to meet demand once Liddell retires in 2022, as well as benefits from allowing more efficient generation sharing between New South Wales and Queensland.

The ISP forecasts the Group 2 upgrade will provide market benefits from fuel cost savings and capital deferral over the longer-term by allowing greater utilisation of renewable energy and coal-fired generation in Queensland, as further generation is developed to achieve the Queensland Renewable Energy Target (QRET). However, the ISP notes the preferred option for this Group 2 upgrade is sensitive to a range of inputs, including New South Wales demand forecasts.

TransGrid and Powerlink have initiated this Regulatory Investment Test for Transmission (RIT-T) to progress the ISP's recommendations to increase the transfer capacity between New South Wales and Queensland. That is, to progress and consult on both the Group 1 and Group 2 upgrades identified by AEMO.

On 12 November 2018, the New South Wales government released the NSW Transmission Infrastructure Strategy that will support early development of the ISP Group 1 project by TransGrid by bringing forward early planning and feasibility work.

In response to a request from the COAG Energy Council, the Energy Security Board (ESB) is currently considering a work program to convert the ISP to an actionable strategic plan. The COAG Energy Council has requested the ESB to report to the December 2018 meeting on how the Group 1 ISP projects can be implemented and delivered as soon as practicable and with efficient outcomes for consumers.

The ‘identified need’ is to provide net market benefits from expanded transfer capacity

The identified need for this RIT-T is to increase overall net market benefits in the NEM through relieving existing and forecast congestion on the transmission network between New South Wales and Queensland.

The key sources of market benefit are expected to be:

- a reduced need for new gas fired generation in New South Wales once the Liddell Power Station retires;
- allowing more efficient generation sharing between New South Wales and Queensland, including greater use of existing, relatively modern, coal-fired generation in Queensland and renewable energy development to meet the QRET; and
- assisting the nation to meet carbon emission and renewable energy targets at lowest long-run cost.

A full RIT-T quantitative analysis will be reported in the Project Assessment Draft Report (PADR). This will involve separate quantification of each key source of expected market benefit across a range of scenarios and sensitivities.

Five types of options are proposed to be assessed, which build on those in the ISP

TransGrid and Powerlink have identified five types of credible options to increase transfer capacity between NSW and Queensland at this stage of the RIT-T, building on the options identified in the ISP. In addition, combinations of these options will be considered.

These options differ principally in scale and technology and include:

- incremental investments to the existing network to modestly increase transfer capacity (Options 1A, 1B, 1C and 1D);
- a new single-circuit 330 kV line from NSW to Queensland (Option 2);
- three variants of a new double-circuit line from NSW to Queensland, including an option that involves 500 kV (Options 3A, 3B and 3C);
- three HVDC options (Options 4A, 4B and 4C); and
- a grid-connected battery system (Option 5).

Options 1A, 1B, 1C and 1D focus on delivering incremental increases in transfer capacity (i.e., consistent with the ISP’s Group 1 upgrade), while options 2-5 focus on delivering additional increases in transfer capacity (i.e., consistent with the ISP’s Group 2 upgrade).

While the ISP found that a new 330 kV double circuit interconnector provided net market benefits over the longer-term, it notes that this finding is sensitive to a range of inputs and suggested that larger capacity options be investigated. Options 2-5 have therefore been developed to further investigate and consult on options for delivering this longer-term increase in transfer capacity.

Box E.1 – The proposed options build on the assessment undertaken in the ISP

The credible options considered in this RIT-T build on the ISP assessment undertaken over 2017 and 2018. In particular, while the ISP Group 1 and Group 2 recommended investments have been included (e.g., Option 1A and Option 3A, respectively), we are now also:

- considering additional low cost incremental options for increasing transfer capacity in the short-term (i.e., options 1B, 1C and 1D);
- considering the use of alternate technologies whose attributes are expected to provide additional benefits (e.g., the synchronous condensers in options 1A and 1C);
- including options with a larger HVAC capacity upgrade as recommended in the ISP (i.e., options 2, 3B and 3C);
- including additional options investigating the use of HVDC technology (i.e., options 4A, 4B and 4C); and
- investigating the use of a grid-integrated battery system (i.e., Option 5).

We have also undertaken significant work to assess each of the potential credible options since the ISP was released. This has included:

- redefining capacity improvements based on power system modelling to develop an updated assessment of the indicative impact on transfer capacity; and
- refining the cost estimates for each of the options.

This RIT-T therefore seeks to progress and consult on the various options and combinations of options for expanding transfer capacity between New South Wales and Queensland, over both the short-term and the longer-term.

A 'first-pass' screening process will be applied to all options, combinations of options, and any others identified during the PSCR consultation process, in preparation of development of the PADR. In particular, while each credible option will be modelled and reported in the PADR, it is expected that the initial list will be refined based on this modelling and that only a subset of these options may be further analysed.

A summary of the potential credible options is provided in Table E.1.

Table E.1 Summary of potential credible options

Option description	Indicative total transfer capacity (MW)[1]		Estimated capex ($m)[2]	Expected delivery time
	Northward	Southward		
Incremental upgrades to the existing network to increase transfer capacity				
Option 1A – Uprate Liddell to Tamworth Lines and install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks*	770	1,215	142	2-3 years
Option 1B – Uprate Liddell to Tamworth Lines only	535	1,030	28	2-3 years
Option 1C - Install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks	595	1,180	114	2-3 years
Option 1D – Sapphire substation cut into line 8C and a mid-point switching station between Dumaresq and Bulli Creek	535	1,165	45	1-2 years
A new single-circuit line from NSW to Queensland				
Option 2 – 330 kV single circuit between Braemar and Liddell	980	1,865	855	3-4 years
A new double-circuit line from NSW to Queensland				
Option 3A – 330 kV double circuit between Bulli Creek and Armidale*	770	1,593	560	3-4 years
Option 3B – 330 kV double circuit line between Braemar and Liddell via Uralla (and establishment of a Uralla 330 kV substation)	1,530	2,160	1,505	4-5 years
Option 3C – 330 kV double circuit line between Braemar and Uralla, 500 kV single circuits between Uralla and Wollar and between Uralla and Bayswater (and establishment of Uralla 500/330 kV substation)	1,695	2,540	2,039	5-6 years
High Voltage Direct Current options				
Option 4A – HVDC back-to-back	1,195	1,780	825	2-3 years
Option 4B – HVDC between Mudgeeraba and Lismore**	765	1,190	600	3-4 years
Option 4C – HVDC between Western Downs and Bayswater**	2,590	2,990	2,100	4-5 years
A grid-connected battery system				
Option 5 - Battery energy storage system	1,135	1,635	1,000	1-3 years

** Option 1A is the ISP recommended Group 1 investment and Option 3A is the ISP recommended Group 2 investment. These are based on the ISP modelling assumptions. The capacity improvements and cost estimates for these options is continuing to be reviewed and will be revised in the PADR.*

*** Power transfer capacities are defined for both the existing HVAC interconnector and for the new HVDC option.*

[1] The transfer capacities shown in this table are indicative for one operating state only (daytime, medium demand) and serve to summarise the notional differences between options.

[2] All cost estimates are to be treated as indicative at this stage and TransGrid and Powerlink will further refine these estimates as part of the PADR.

Non-network options can assist in expanding transfer capacity

TransGrid and Powerlink are interested to hear from potential proponents of non-network options.

Section 4 of this report outlines how non-network technologies can contribute to meeting the identified need of relieving existing and forecast congestion on the transmission network between New South Wales and Queensland over the short and medium term. We also present a number of potential technologies that could assist.

In particular, we set out both:

- general information on how non-network options can assist with increasing transfer capacity; and
- specific information on the use of a potential Wide Area System Integrity Protection Scheme.

Proponents of non-network options are encouraged to make submissions on any non-network option they believe can address, or contribute to, the identified need.

We encourage proponents to reach out and contact us as soon as practicable about potential solutions, ahead of preparing a formal submission.

The information provided in submissions will be used to further develop non-network options for inclusion in the next stage of the RIT-T assessment process.

Next steps

TransGrid and Powerlink welcome written submissions on this PSCR. Submissions are due on or before 22 February 2019. Submissions are particularly sought on the credible options presented and from potential proponents of non-network options that could meet the technical requirements set out in this PSCR.

TransGrid and Powerlink will also publish an accompanying input and methodology consultation paper. This document will provide greater detail in relation to the modelling approach and parameters we intend to adopt in the quantitative RIT-T analysis. This separate report will be published in addition to the NER requirements for a RIT-T and will provide greater transparency and opportunity to obtain earlier stakeholder feedback on the quantitative modelling, ahead of the Project Assessment Draft Report (PADR).

Submissions should be emailed to regulatory.consultation@transgrid.com.au

Submissions will be published on the TransGrid and Powerlink websites. If you do not wish for your submission to be made publicly available, please clearly specify this at the time of lodgement.

The next formal stage of this RIT-T is the PADR. The PADR will include the full quantitative analysis of both network and non-network options, and is expected to be published during 2019.

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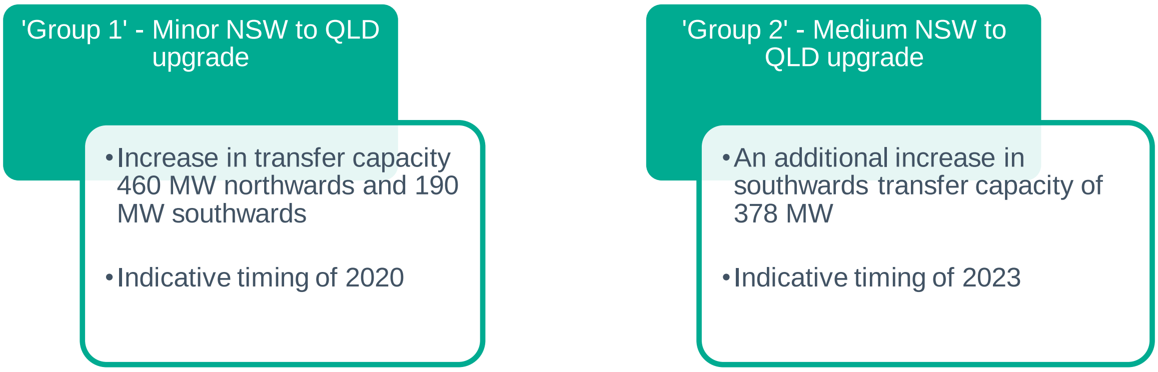
1. Introduction

The National Electricity Market (NEM) is currently undergoing rapid change as the sector transitions to a world with lower carbon emissions and greater uptake of emerging technologies. Renewable energy is making up an increasing proportion of the national energy mix.

The inaugural Integrated System Plan (ISP), released by the Australian Energy Market Operator (AEMO) in July 2018, recommended two key transmission investments in relation to transfer capacity between New South Wales and Queensland necessary to support the long-term interests of consumers for safe, secure, reliable electricity, at the least cost, across a range of plausible futures.

AEMO differentiated these two investments as being needed over the immediate-term (by around 2020) and over the medium-term (by the mid-2020s), respectively, as shown in Figure 2.

Figure 2 The AEMO ISP recommended two expansions to NSW-QLD transfer capacity



The ISP concluded that by 2020, or as soon as they can be built, market benefits associated with the Group 1 upgrade can be realised due to a reduced need for new gas fired generation in New South Wales to meet demand once Liddell retires in 2022, as well as benefits from allowing more efficient generation sharing between New South Wales and Queensland.

The ISP forecasts the Group 2 upgrade will provide market benefits from fuel cost savings and capital deferral over the longer-term by allowing greater utilisation of renewable generation and relatively modern coal-fired generation in Queensland, as further generation is developed to achieve the Queensland Renewable Energy Target (QRET). However, the ISP notes the preferred option for this Group 2 upgrade is sensitive to a range of inputs, including New South Wales demand forecasts.

TransGrid and Powerlink have initiated this Regulatory Investment Test for Transmission (RIT-T) to progress the ISP's recommendations to increase the transfer capacity between New South Wales and Queensland. That is both Group 1 and Group 2 investments noted above.

On 12 November 2018, the New South Wales government released the NSW Transmission Infrastructure Strategy that will support early development of the ISP Group 1 project by TransGrid by bringing forward early planning and feasibility work.

In response to a request from the COAG Energy Council, the Energy Security Board (ESB) is currently considering a work program to convert the ISP to an actionable strategic plan. The COAG Energy Council has requested the ESB to report to the December 2018 meeting on how the Group 1 ISP projects can be implemented and delivered as soon as practicable and with efficient outcomes for consumers.

This RIT-T process will be undertaken in consultation with consumers, AEMO, Registered Participants and other interested parties regarding the investment options under consideration.

1.1 Understanding the investment approval process

The current regulatory framework requires that to initiate transmission projects, including those identified in the ISP, a TNSP must conduct a RIT-T.

The RIT-T considers all credible options to meet an identified need, in order to demonstrate efficient investment in the transmission network and provides an opportunity for meaningful engagement with a range of interested parties, including non-network providers, to promote investment.

1.1.1 Principles and application of the RIT-T

The RIT-T is an explicit cost-benefit analysis under the National Electricity Rules (NER) that is designed to support the planning and investment making decisions of transmission network service providers (TNSPs).

The RIT-T is a three-stage process the purpose of which is to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the market, i.e., the economic analysis and factors assessed are applied in the context of the National Electricity Market (NEM). The AER has developed RIT-T Application Guidelines to ensure a consistent approach is applied to RIT-Ts and identifies that certain costs and benefits may not be included in the cost-benefit analysis (referred to as 'externalities').[3]

These externalities include:

- Direct benefits to consumers or generators from changes in electricity prices – while the RIT-T captures the benefit of changes in electricity supply costs (such as capital costs, operating and maintenance costs and fuel costs), any changes in electricity prices are treated as an economic 'transfer' between parties and therefore not captured in the analysis.
- Economic benefits outside of the NEM – for example, the RIT-T does not include:
  - the benefit to gas consumers from any reduced gas consumption in the NEM;
  - regional economic benefits from investment in generation and transmission, e.g., job creation; or
  - the direct value of reduced emissions in the electricity sector.

Detailed information on the RIT-T process can be found on the AER's website.

1.1.2 Subsequent stages of the process

The current AER revenue determinations for TransGrid[4] and Powerlink[5] require that, following completion of this RIT-T, the AER must make a determination on its conclusion in order for the TNSPs to subsequently trigger a 'contingent project'. The process for the determination differs slightly depending whether a dispute is raised with the AER on conclusion of the RIT-T.

Following the RIT-T, the proponent of the preferred option will also consider their Final Investment Decision (FID) on whether to proceed with the project. The proponent will take into account, amongst other factors, whether the project is investable.

If the AER's determination on the RIT-T and the proponent's FID are favourable, the proponent may then apply to the AER to trigger a 'contingent project'. The contingent project mechanism is used to amend the TNSP's revenue determination to include the project, once the scope and cost of the proposed project are known. This provides funding to the TNSP to initiate and commence the project.

[3] Further information on the application of the RIT-T and the treatment of externalities is available in RIT-T Application Guidelines, p. 53.

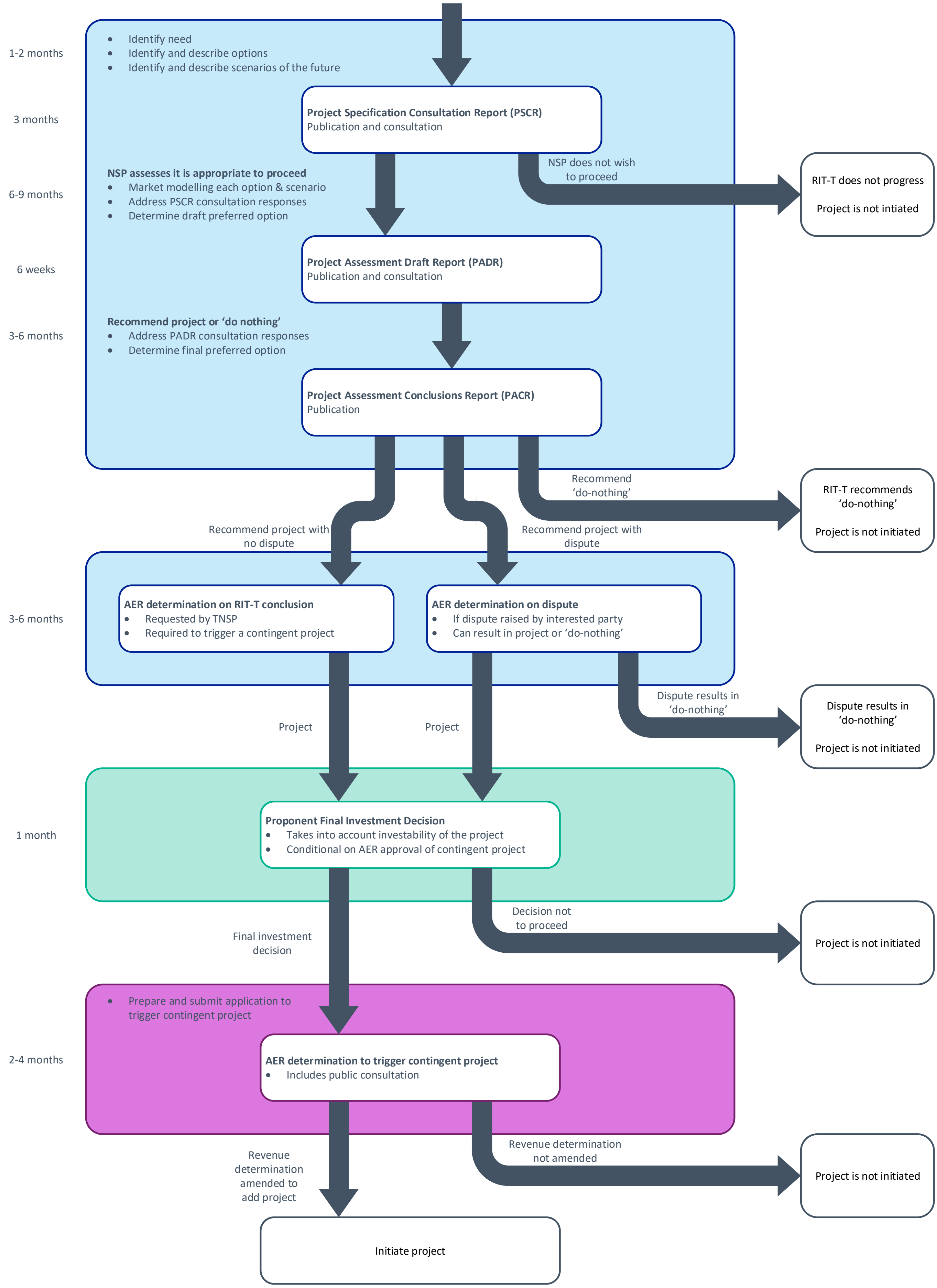
[4] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/transgrid-determination-2018-23/final-decision

[5] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powerlink-determination-2017-2022/final-decision

The process, including statutory timeframes as set out in the NER and reasonable expected timeframes for supporting analysis, is shown in Figure 3. In response to a request from the COAG Energy Council, the Energy Security Board is currently considering a work program to convert the ISP to an actionable strategic plan.[6] If this work program results in changes to the process to initiate projects identified in the ISP, the process and timeframes may change.

6 COAG Energy Council, *Meeting Communique*, 10 August 2018, p. 2.

Figure 3 Schematic representation of the RIT-T process



1.2 Role of this report

This Project Specification Consultation Report (PSCR) represents the first step in RIT-T process.

The purpose of the PSCR is to:

1. set out the reasons why TransGrid and Powerlink propose that action be undertaken (that is, the 'identified need');
2. present credible network options that can address the identified need;
3. provide details as to what non-network solutions would need to deliver in order to help address the identified need, and invite submissions from proponents of potential non-network options to be included in the RIT-T assessment; and
4. provide an opportunity for interested parties to make submissions and comment on the proposed RIT-T assessment assumptions and methodology.

Further information in relation to the assumptions proposed for the market modelling for this RIT-T assessment is provided in a separate report.

TransGrid and Powerlink are required to apply the RIT-T to this investment, as none of the exemptions listed in NER clause 5.16.3(a) apply.

TransGrid and Powerlink have classified this project as a contingent project in their Revenue Proposals for the 2018-2023 period and 2017-2022 period, respectively, due to uncertainties regarding the preferred option to practicably deliver the greatest expected net market benefits. Successful application of this RIT-T is one of the triggers proposed for these contingent projects.

1.3 Submissions and next steps

TransGrid and Powerlink welcome written submissions on this PSCR. Submissions are due on or before 22 February 2019. Submissions are particularly sought on the credible options presented and from potential proponents of non-network options that could meet the technical requirements set out in this PSCR.

Submissions should be emailed to regulatory.consultation@transgrid.com.au

Submissions will be published on the TransGrid and Powerlink websites. If you do not wish for your submission to be made publicly available, please clearly specify this at the time of lodgement.

The next formal stage of this RIT-T is the Project Assessment Draft Report (PADR). The PADR will include the full quantitative analysis of both network and non-network options, and is expected to be published during 2019.

Since the interconnector options considered in this report are all expected to have a material inter-network impact, TransGrid and Powerlink will also provide AEMO with a written request for an augmentation technical report.[7]

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[7] In accordance with NER clause 5.21(d).

2. The ‘identified need’

This section discusses the drivers for potential investment under this RIT-T (‘the identified need’), and why it is considered that material market benefits will arise as a result of this investment. It first outlines relevant background on the current interconnection between New South Wales and Queensland.

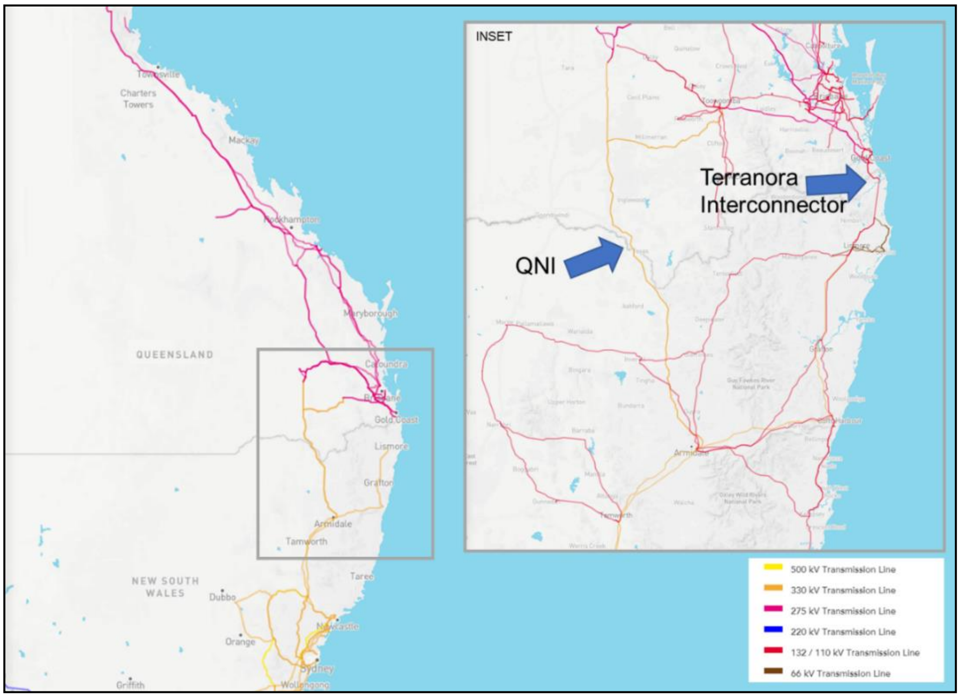
2.1 Current interconnection between New South Wales and Queensland

The New South Wales and Queensland electricity transmission networks are connected by two interconnectors – namely:

- Queensland to New South Wales Interconnector (QNI) – a high voltage alternating current (HVAC) 330kV transmission line connecting two power systems with a transfer capacity of 310 MW from New South Wales to Queensland (‘northwards’) and 1,025 MW from Queensland to New South Wales (‘southwards’) as per the AEMO ISP analysis.[8] QNI is operated under a joint operating agreement between TransGrid and Powerlink.
- Terranora Interconnector – a high voltage alternating current (HVAC) 110kV double circuit between Mudgeeraba substation in Queensland and Terranora substation in NSW. Terranora is connected to the rest of the New South Wales network through high voltage direct current (HVDC) transmission lines referred to as Directlink. Directlink has three pairs of bipolar transmission cables with a capacity to deliver a maximum of 180 MW in either direction. Directlink is operated by the APA Group.

The existing transmission networks in northern New South Wales and southern Queensland are shown in Figure 4, with the two existing interconnectors between the states highlighted.

Figure 4 Existing transmission networks in Northern NSW and Southern Queensland



Source: Adapted from the AEMO Interactive Map of Australia’s energy infrastructure, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Interactive-maps-and-dashboards

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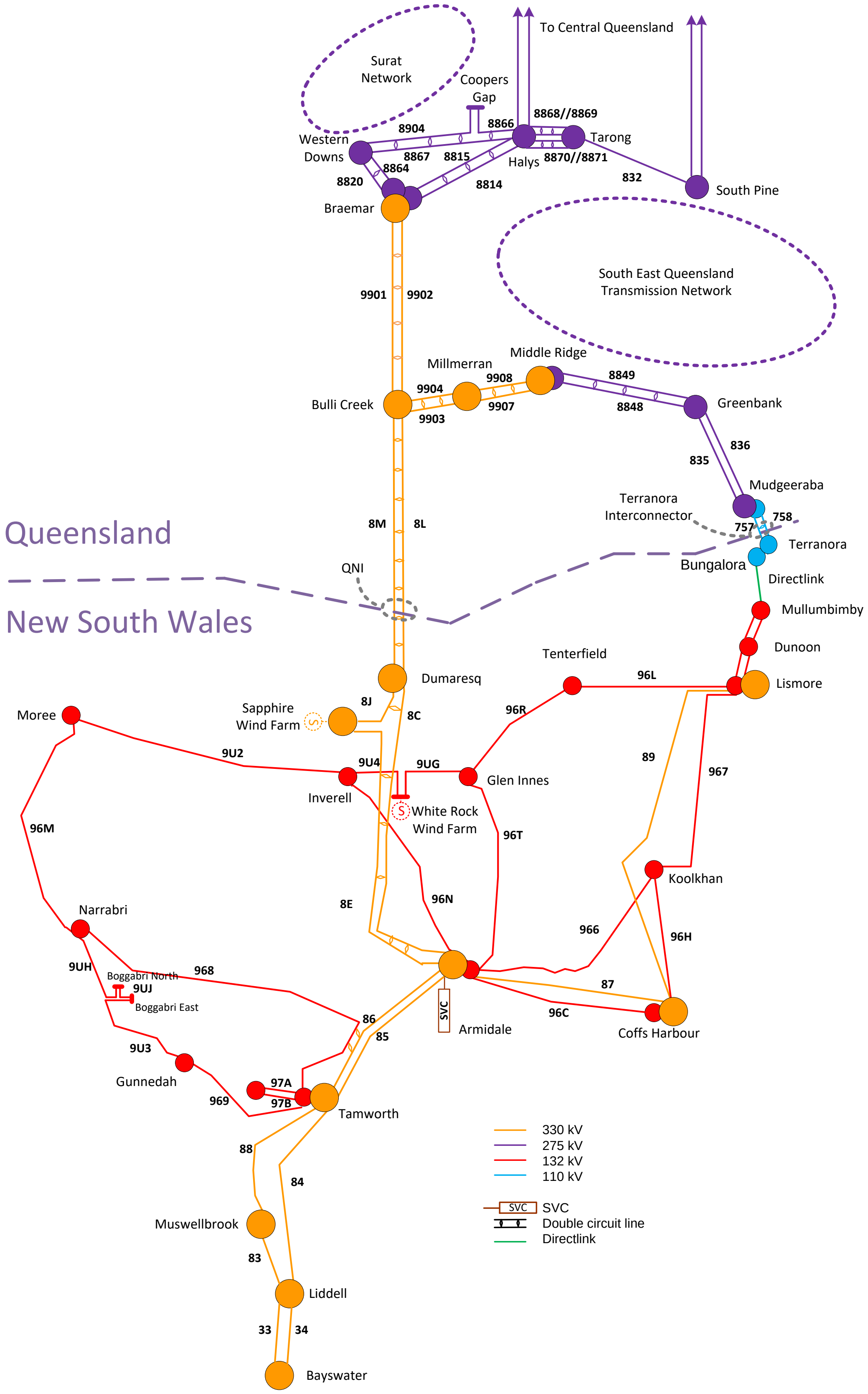
[8] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/2018-Integrated-System-Plan--Modelling-Assumptions.xlsx

Figure 5 shows a one-line diagram of the relevant transmission network in northern New South Wales and southern Queensland. It includes line names that are referenced throughout this report.

Figure 5 Specific transmission lines in northern New South Wales and southern Queensland



2.2 Preliminary assessment of the expected benefits from increasing transfer capacity

In 2014, TransGrid and Powerlink jointly undertook a RIT-T that investigated a range of options for increasing the transfer capacity of QNI in order to deliver market benefits following a number of network, generation and load developments at the time. A Project Assessment Conclusions Report was published in November 2014 with the finding that the preferred option was critically dependent on the set of underlying assumptions used to estimate net market benefits. In many cases, an upgrade was not expected to deliver net market benefits.

The 2014 RIT-T assessment identified four important factors that influenced the estimated market benefits of credible options – namely:

- future gas prices in Queensland;
- the, then, possible retirement of Redbank Power Station;
- the development of wind farms in northern New South Wales; and
- general load growth.

TransGrid and Powerlink considered that there was too much uncertainty around these factors at the time and that it was ultimately prudent to not recommend a preferred option. Instead, TransGrid and Powerlink stated that they would continue to monitor developments in these key input assumptions going forward and reinitiate this investigation when prudent to do so.

Since 2014, the NEM has experienced a period of significant change. As part of this, there have been a number of important developments to the key factors outlined above, including gas prices increasing markedly in Queensland (and the east coast generally) due to LNG exports commencing in December 2014; Redbank Power Station closing in New South Wales (as well as Munmorah and Wallerawang in New South Wales, Hazelwood in Victoria, Northern Power Station in South Australia and announcements and expectations for further power station closures across the NEM); and new wind farms locating in northern New South Wales.

In addition, the Queensland government has committed to a 50 per cent Queensland Renewable Energy Target (QRET) by 2030.[9]

As a result of these factors, the transfer capacity of QNI is forecast to be increasingly utilised, leading to increased network congestion between Queensland and New South Wales.

The line thermal rating limits across the majority of the interconnection are typically higher than the voltage control or stability limits. This means that investments to relieve the voltage control and stability limits can increase the effective capacity of the interconnection and potentially deliver market benefits.

The ISP, released by AEMO in July 2018, identified that relieving these transmission constraints is expected to provide substantial market benefits. In particular, the ISP identified two key transmission investments in relation to increasing transfer capacity between New South Wales and Queensland necessary to support the long-term interests of consumers. Specifically, the ISP recommended:[10]

- An initial upgrade by 2020 that:
  - > increases transfer capacity by 460 MW (up to a limit of 770 MW) in a northwards direction and 190 MW (up to a limit of 1,215 MW) in a southwards direction; and
  - > involves transmission works solely in New South Wales.
- A medium-term upgrade by 2023 that:

9 https://www.dnrme.qld.gov.au/energy/initiatives/powering-queensland

10 AEMO, *Integrated System Plan,* July 2018, pp. 8-9.

- provides a further 378 MW increase in transfer capacity in a southwards direction; and
- involves transmission works in both states.

The initial upgrade has been identified as 'Group 1' as AEMO anticipates it can be delivered sooner than the medium-term works (identified as 'Group 2'). AEMO notes that the medium-term upgrade is of a larger scale and will require longer lead times to design and develop, particularly for any option that requires establishing a new transmission corridor. However, AEMO recommended that work should commence immediately on refining the requirements, finalising the design and establishing implementation processes and plans.[11]

The ISP concluded that by 2020, or as soon as they can be built, market benefits associated with the minor upgrade can be realised. Principally these market benefits arise from:[12]

- a reduction in the need for new gas fired generation in New South Wales to meet demand once Liddell retires in 2022; and
- more efficient generation sharing between New South Wales and Queensland.

The medium upgrade is projected to provide market benefits from fuel cost savings and capital deferral by allowing greater use of renewable generation and coal-fired generation fleet in Queensland, as further generation is developed to meet the QRET.[13] However, AEMO notes that the preferred option for the Group 2 upgrade is sensitive to a range of inputs, including New South Wales demand forecasts.[14]

The ISP recommendations align with preliminary market modelling analysis undertaken by TransGrid and Powerlink during 2017. This analysis indicated that there are net market benefits associated with relieving constraints on the existing interconnector as a result of the continuing transformation of the Australian energy industry. It is also consistent with the 2016 NTNDP, which found that a QNI upgrade was economic in the mid to late 2020s.[15]

On 12 November 2018, the New South Wales government released the NSW Transmission Infrastructure Strategy that will support early development of the ISP Group 1 project by TransGrid by bringing forward early planning and feasibility work.

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[11] AEMO, *Integrated System Plan,* July 2018, p. 84.

[12] AEMO, *Integrated System Plan,* July 2018, p .83.

[13] AEMO, *Integrated System Plan,* July 2018, p. 94.

[14] AEMO, *Integrated System Plan | Appendices,* July 2018, p. 59.

[15] As part of the 2016 NTNDP, AEMO's studies showed that a QNI upgrade might be economic in the mid to late 2020s. The NTNDP modelling indicated that the QNI augmentations was net beneficial and was consequently incorporated into the base cases for all three 2016 NTNDP scenarios. The release of the 2017 NTNDP was deferred by the Australian Energy Regulator and formed part of the 2018 ISP.

2.3 Description of the 'identified need' for this RIT-T

The identified need for this RIT-T is to increase overall net market benefits in the NEM through relieving existing and forecast congestion on the transmission network between Queensland and New South Wales.

TransGrid and Powerlink have initiated this RIT-T to progress the ISP's recommendations to increase the transfer capacity between New South Wales and Queensland, i.e., both Group 1 and Group 2 ISP projects.

The ISP assessment concluded that there are market benefits for:[16]

- Group 1 investments by 2020, or as soon as they could be delivered, arising from a reduced need for new gas fired generation in New South Wales to meet demand once Liddell retires in 2022, as well as benefits from allowing more efficient generation sharing between New South Wales and Queensland; and
- Group 2 investments over the longer-term from fuel cost savings and capital deferral by allowing greater use of existing relatively modern coal-fired generation in Queensland, and renewable energy development to achieve the QRET.

A reduced need for new investment in generating plant, or a deferral of generation investment, represents a key market benefit under the RIT-T.[17]

Given the non-coincidence of peak demand in Queensland and New South Wales, an expansion of the interconnector transfer capacity is also expected to improve the utilisation of existing plant across the NEM to meet peak demand requirements and help enable demand in each region to be met using surplus low cost generating capacity. Sharing of generation is therefore also expected to facilitate substitution of high-fuel cost plant with low-fuel cost plant, which would lower the overall cost of dispatch. This is another key category of market benefit under the RIT-T.[18]

The benefits of the sharing of regional generation are of heightened importance in supporting significant levels of variable renewable energy during times of solar or wind droughts.

Greater interconnection between New South Wales and Queensland would also allow renewable energy in these regions to assist the nation to meet carbon emission and renewable energy targets at lowest long-run cost. Opening up additional geographical areas of the NEM for renewable investment will drive diversification of renewable energy and lead to less volatility in output as a result of local weather effects. Within the context of the RIT-T assessment, greater output from renewable generation can be expected to primarily deliver the following classes of market benefit:

- further reductions in total dispatch costs, by enabling low cost renewable generation to displace higher cost conventional generation;
- reduced generation investment costs, resulting from more efficient diversified investment and retirement decisions, due to high quality wind, solar and pumped-hydro generation being able to locate at optimal locations rather than inferior locations limited by congestion on the existing transmission system; and

Expanding the transfer capacity between New South Wales and Queensland is therefore also considered to lower the cost of facilitating the NEM's transition to lower carbon emissions and the adoption of new technologies.

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16 AEMO, *Integrated System Plan,* July 2018, pp .83 & 94.

17 Specifically, 'changes in costs for parties, other than the RIT–T proponent, due to differences in the timing of new plant, capital costs, and operating and maintenance costs'. AER, *Regulatory Investment Test for Transmission*, June 2010, p. 4.

18 Specifically, 'changes in fuel consumption arising through different patterns of generation dispatch'. AER, *Regulatory Investment Test for Transmission*, June 2010, p. 4.

2.4 Assumptions underpinning the identified need

At a high-level, the assumptions that will be used to assess the market benefits in the PADR will be based on the 2018 ISP assumptions. We propose to modify these assumptions only where they have been updated by AEMO since, as well as part of the scenario and sensitivity testing to stress test the effects of assuming alternate key assumptions.

TransGrid and Powerlink will also publish an input and methodology consultation paper. This document will provide greater detail in relation to the modelling approach and parameters we intend to adopt in the quantitative RIT-T analysis. This separate report will be published in addition to the NER requirements for a RIT-T and will provide greater transparency and opportunity to obtain earlier stakeholder feedback on the quantitative modelling, ahead of the PADR.

2.4.1 Summary of the broad ISP scenarios proposed to be investigated

TransGrid and Powerlink note the importance of ensuring that the outcome of this RIT-T assessment is robust to different assumptions about how the energy sector may develop in the future. Interconnector investments are long-lived assets, and it is important that the market benefits associated with these investments do not depend on a narrow view of potential future outcomes, given that the future is inherently uncertain.

Uncertainty is captured under the RIT-T framework through the use of scenarios, which reflect different assumptions about future market development, and other factors that are expected to affect the relative market benefits of the options being considered.

We are intending to construct three 'core' scenarios that we consider reflect a sufficiently broad range of potential outcomes across the key uncertainties that are expected to affect the future market benefits of the investment options being considered. The inputs feeding into each scenario align in all material respects with AEMO's ISP inputs, except for where AEMO has updated key assumptions since (e.g., in its 2018 Electricity Statement of Opportunities (ESOO)).

The key variables that influence the net market benefits of the options are summarised in Table 2.

Table 2 Summary of scenarios proposed to be modelled

Variable	Neutral 'state-of-the-world' scenario	Slow change 'state-of-the-world' scenario	Fast change 'state-of-the-world' scenario
Electricity demand	AEMO 2018 ESOO neutral demand forecasts	AEMO 2018 ESOO weak demand forecasts	AEMO 2018 ESOO strong demand forecasts
Coal and gas prices	AEMO ISP neutral forecast	AEMO ISP slow forecast	AEMO ISP strong forecast
Emission reduction renewables policy	28% reduction from 2005 by 2030	28% reduction from 2005 by 2030	52% reduction from 2005 by 2030
Jurisdictional emissions targets	VRET 25% by 2020 and 40% by 2025 QRET 50% by 2030	VRET 25% by 2020 and 40% by 2025 QRET 50% by 2030	VRET 25% by 2020 and 40% by 2025 QRET 50% by 2030

Table 2 only summarises key variables that are expected at this stage to have the greatest influence on the net market benefits of the options considered. The accompanying input and methodology consultation report will provide more detail in relation to the modelling approach and all parameters we intend to adopt in the quantitative RIT-T analysis. The recently released NSW Transmission Infrastructure Strategy will be factored into the scenarios as part of the PADR stage.

While uncertainty is captured under the RIT-T framework through the use of scenarios, the robustness of the economic assessment presented in the PADR will be thoroughly investigated through the use of sensitivity analysis in relation to key input assumptions. In particular, we intend to identify the key factors driving the outcome of this RIT-T through this sensitivity testing and will seek to identify the 'boundary value' for these factors, beyond which the outcome of the analysis would change, e.g., investigating what a particular variable would need to change by for the preferred credible option to change.

At this stage, based on the ISP assessment and the preliminary modelling undertaken by TransGrid and Powerlink during 2017, we consider that the following are candidates for this detailed sensitivity testing:

- retirement dates of coal generators (particularly Vales Point, Eraring and Bayswater in New South Wales and Gladstone and Tarong in Queensland);
- electricity demand (and New South Wales demand in particular, as highlighted in the ISP);
- potential coincident, and/or subsequent, network developments (e.g., other ISP 'Group 1'[19] and 'Group 2'[20] projects, ISP 'Group 3' projects[21], Snowy 2.0, the outcomes of the Western Victoria Renewable Integration RIT-T and the South Australian Energy Transformation RIT-T); and
- capital costs of new generating units and the credible options.

However, we will assess all key inputs as part of this sensitivity exercise and determining their significance to the draft preferred option at the PADR stage.

While the retirement of Liddell is expected to be a key driver of market benefits for the credible options considered (as highlighted in the ISP), we consider there to be less uncertainty around the retirement date of Liddell than other NSW coal plants.[22] We are therefore not intending to test a sensitivity on the assumed retirement date of Liddell in the PADR.

The sensitivity of the net market benefits to all key underlying assumptions will be thoroughly tested and reported in the PADR.

2.4.2 The nature of demand in New South Wales and Queensland

Market benefits from increasing transfer capacity between Queensland and New South Wales arise as a result of peak demand in each region (and other interconnected regions) occurring at different times. The non-coincidence of demand enables generation capacity to be shared across the interconnected system.

Diversity of peak demand across geographically diverse areas, such as the eastern seaboard of Australia, occurs primarily due to differing weather conditions. Generally, there has been diversity between peak demands in New South Wales and Queensland (that is peak demands have generally not been coincident). This provides an opportunity for generator capacity sharing between the two regions.

Figure 6 illustrates how peak demand in New South Wales and Queensland are largely non-coincident, using New South Wales summer peak as a base. In particular, it shows that, over the last seven years, when New South Wales demand was at its historical annual peaks, coincident Queensland demand was between 630 MW and 1,700MW below its annual peak.

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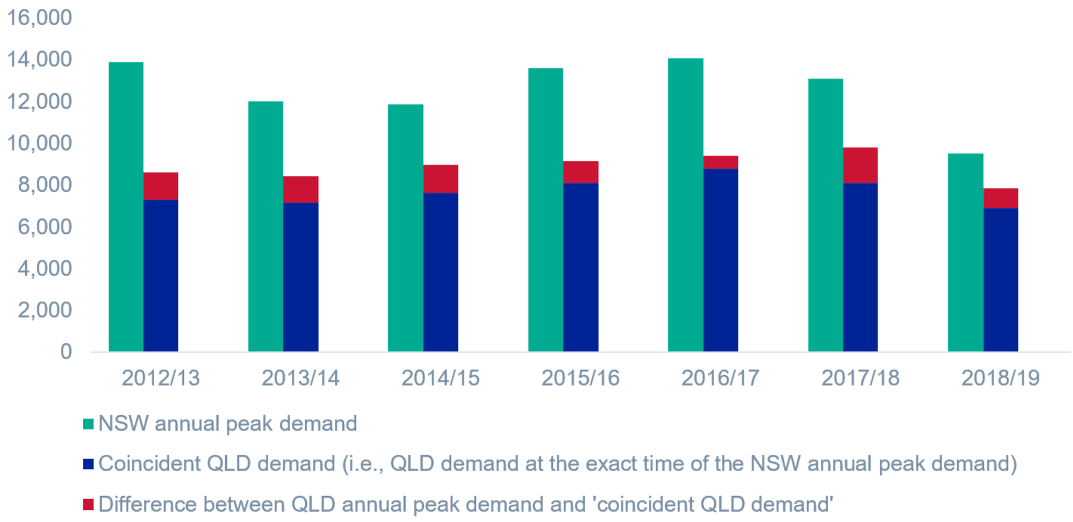
19 The 2018 ISP classifies three projects as 'Group 1' – ie: (1) increase transfer capacity between New South Wales, Queensland, and Victoria by 170-460 MW; (2) reduce congestion for existing and committed renewable energy developments in western and north-western Victoria; and (3) remedy system strength in South Australia.

20 The 2018 ISP classifies five projects as 'Group 2' – ie: (1) establish new transfer capacity between New South Wales and South Australia of 750 MW ('RiverLink'); (2) increase transfer capacity between Victoria and South Australia by 100 MW; (3) increase transfer capacity between Queensland and New South Wales by a further 378 MW (QNI); (4) efficiently connect renewable energy sources through maximising the use of the existing network and route selection of the above developments; and (5) coordinate DER in South Australia.

21 The 2018 ISP classifies two projects as 'Group 3' – ie: (1) Increase transfer capacity further between New South Wales and Victoria by approximately 1,800 MW ('SnowyLink'); and (2) Efficiently connect renewable energy sources through additional intra-regional network development.

22 AGL have made numerous announcements that they are going to retire Liddell by 2022. AEMO also classify Liddell as an 'Announced Retirement' in their generator information pages, while the other NSW coal plants are still listed as 'In Service".

Figure 6 Coincidence of peak demand between NSW and Queensland



2.4.3 The nature of limitations on the existing network

The transfer capability across QNI is limited by voltage stability, transient stability, oscillatory stability, and line thermal ratings. The capability across QNI at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network.

For intact system operation, the transfer from Queensland to New South Wales is mainly limited by the following constraints:

- stability limits for faults on either Sapphire to Armidale or Armidale to Dumaresq line;
- thermal capacity of the 330 kV lines within northern NSW; and
- oscillatory stability upper limit of 1,200 MW.

For intact system operation, the transfer from New South Wales to Queensland is mainly limited by the following constraints:

- stability limits on loss of the largest Queensland unit;
- transient stability associated with transmission line faults in the Hunter Valley;
- voltage collapse for trip of the Liddell to Muswellbrook 330 kV line;
- thermal capacity of the 330 kV and 132 kV transmission lines within northern New South Wales; and
- the oscillatory stability upper limit of 700 MW.

In addition, since January 2016, Queensland has seen an unprecedented level of renewable energy investment activity in north and central Queensland, with over 1,600 MW of large scale renewable energy projects commencing construction or finalising commercial arrangements.[23] This will continue as Queensland moves towards its QRET target of 50 per cent renewable generation by 2030. Powerlink continues to process numerous connection applications many of which are in central and north Queensland.

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[23] Please refer to tables 6.1 and 6.2 of Powerlink's 2018 TAPR.

In order for power from these new and existing generating systems to make its way to the southern states, it must be transferred through the Gladstone and Central Queensland to South Queensland ('CQSQ') grid sections. The utilisation of the CQSQ grid sections is therefore expected to increase with additional development and Powerlink's modelling shows that, depending on market outcomes, these intra-regional transmission corridors may prevent some of the potential market benefits from increased interconnector capacity.[24]

Powerlink therefore expects that there may be congestion in the central Queensland network due to transmission capacity unless central Queensland base load generators 'choose' to decommit or run at substantially lower capacity factors than they have historically. In addition, the incidence of congestion will be increased with additional southerly transfer capacity on QNI.

Powerlink is continuing to investigate the impact on, and interaction with, the QNI transfer limits from these CQSQ constraints, as well as other intra-Queensland constraints. Should any material constraints emerge as part of this, additional information will be published on these constraints, any potential network solutions to addressing them and explicitly call for responses from non-network proponents.

Overall, any RIT-T assessment must be cognisant of the performance of major intra-regional grid sections. This is particularly relevant when assessing the economic merits of developing renewable energy zones and/or when locating the generation capacity expansions plans within regions of the NEM. Any new capacity may change materially the utilisation of intra-regional grid sections and intra-regional losses but may also lead to congestion rendering some generation investments inefficient.

2.4.4 Renewable energy potential near the QNI corridor

Australia's COP21[25] commitment to reduce carbon emissions by 26 to 28 per cent below 2005 levels by 2030 has significant implications for the future operation of the NEM. Meeting this commitment will lead to further replacement of some of Australia's emissions intensive generators with lower emission alternatives, such as renewable energy.[26]

The areas of northern New South Wales and southern Queensland have some of highest quality renewable energy resources in Australia, including solar, wind and pumped-hydro potential.

As part of the ISP, an extensive investigation of the renewable energy resources in, and near, existing NEM infrastructure was undertaken by AEMO. In particular, the ISP outlines potential renewable energy zones across the NEM and includes four directly on the existing QNI route, as shown in Figure 7 (i.e., zones 6, 7, 8 and 30).

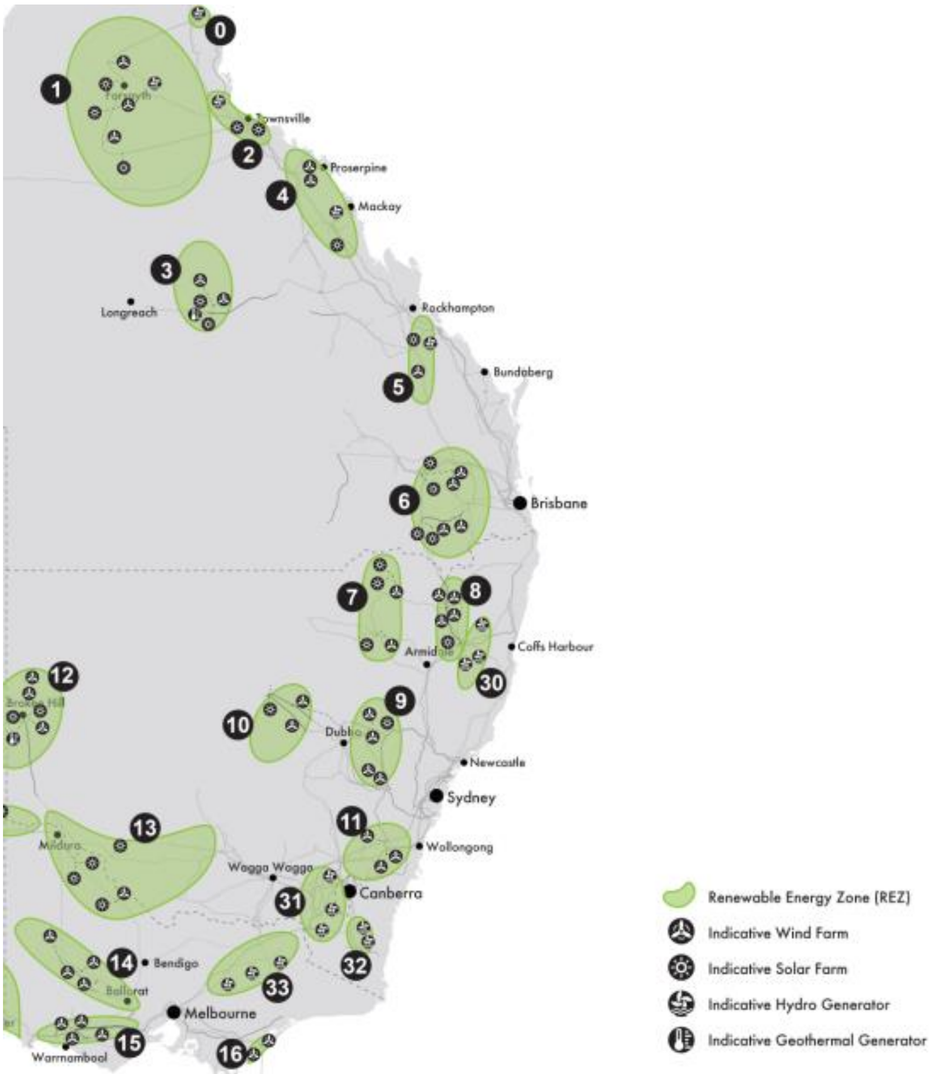
The ISP investigations have confirmed that there are good solar resources at the west of QNI corridor and there are good wind and pumped hydro resources at the east of QNI corridor.

[24] Section's 6.6.3 and 6.6.4 of Powerlink's 2018 TAPR describe the factors affecting the available capacity of these intra-connectors.

[25] The 2015 United Nations Climate Change Conference (also known as 'COP 21' or 'CMP 11') was held in Paris, France, from 30 November to 12 December 2015.

[26] COAG Energy Council, Review of the Regulatory Investment Test for Transmission, Consultation Paper, Energy Project Team, 30 September 2016, p. 13.

Figure 7 AEMO ISP – Renewable Energy Zone candidates in NSW and Queensland



Source: Adapted from the AEMO Integrated System Plan, July 2018, p. 50.

Importantly for this RIT-T, the Queensland government has committed to a range of renewable actions, including:[27]

- the Queensland Renewable Energy Target ('QRET') – a renewable energy target of 50 per cent by 2030; and
- facilitating the next wave of up to 400 MW of diversified renewable energy.

To ensure efficient transmission and distribution network connections, the Queensland government is also working with Powerlink and Energy Queensland to handle the increased workload.[28]

AEMO incorporated the Queensland Government's renewable energy policies in all cases and scenarios studied as part of the ISP.[29]

Expanding the transfer capacity of QNI will allow the Queensland renewable developments to be efficiently exported and will avoid other generation output and investment elsewhere in the NEM.

27 https://www.dnrme.qld.gov.au/__data/assets/pdf_file/0008/1253825/powering-queensland-plan.pdf, https://www.dnrme.qld.gov.au/__data/assets/pdf_file/0006/1253832/transitioning-to-low-carbon-energy-sector.pdf

28 https://www.dnrme.qld.gov.au/__data/assets/pdf_file/0006/1253832/transitioning-to-low-carbon-energy-sector.pdf page 2

29 AEMO, *Integrated System Plan*, June 2018, pp. 20 & 25.

3. Potential credible options

TransGrid and Powerlink have identified five types of credible options to increase transfer capacity between NSW and Queensland at this stage of the RIT-T, building on the options set out in the ISP. In addition, combinations of these options will be considered.

These options differ principally in scale and technology and include:

- incremental investments to the existing network to modestly increase transfer capacity (Options 1A, 1B, 1C and 1D);
- a new single-circuit 330 kV line from NSW to Queensland (Option 2);
- three variants of a new double-circuit line from NSW to Queensland, including an option that involves 500 kV (Options 3A, 3B and 3C);
- three HVDC options (Options 4A, 4B and 4C); and
- a grid-connected battery system (Option 5).

Options 1A, 1B, 1C and 1D focus on delivering incremental increases in transfer capacity. Option 1A is the Group 1 option identified in the ISP, while options 1B, 1C and 1D have been included based on additional work undertaken since the ISP was released and reflect alternate, lower cost, options for increasing transfer capacity between the states.

Options 2-5 focus on delivering a larger increase in transfer capacity In particular, the ISP considered a number of options for this upgrade, with the preferred option being to expand the existing transmission corridor by constructing new Armidale-Dumaresq and Dumaresq-Bulli Creek 330kV double circuit lines and augmenting existing substations/switching stations at Armidale, Dumaresq and Bulli Creek. The ISP recommended Group 2 option has been included in this RIT-T as Option 3A.

While the ISP found that a new 330 kV double circuit interconnector provided net market benefits, it notes that it is sensitive to a range of inputs and that alternatives to this option should be considered in a RIT-T. Options 2-5 have therefore been developed to further investigate and consult on options for delivering this longer-term increase in transfer capacity.

Consistent with the ISP recommendation, we are explicitly including options with a larger HVAC capacity upgrade than that recommended in the ISP (Option 2, 3B and 3C), as well as options investigating the use of HVDC technology (Options 4A, 4B and 4C).[30]

We have undertaken significant work to assess each of the potential credible options since the ISP was released. This has included:

- redefining capacity improvements based on power system modelling to develop an updated assessment of the indicative impact on transfer capacity; and
- refining the cost estimates for each of the options.

Table 3 summarises each of the credible options considered at this stage. The transfer capacities shown are indicative for one operating state only and serve to summarise the notional differences between options.

30 AEMO, *Integrated System Plan*, June 2018, p. 87.

Table 3 Summary of potential credible options

Option description	Indicative total transfer capacity (MW)[31]		Estimated capex ($m)[32]	Expected delivery time
	Northward	Southward		
Incremental upgrades to the existing network to increase transfer capacity				
Option 1A – Uprate Liddell to Tamworth Lines and install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks*	770	1,215	142	2-3 years
Option 1B – Uprate Liddell to Tamworth Lines only	535	1,030	28	2-3 years
Option 1C - Install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks	595	1,180	114	2-3 years
Option 1D – Sapphire substation cut into line 8C and a mid-point switching station between Dumaresq and Bulli Creek	535	1,165	45	1-2 years
A new single-circuit line from NSW to Queensland				
Option 2 – 330 kV single circuit between Braemar and Liddell	980	1,865	855	3-4 years
A new double-circuit line from NSW to Queensland				
Option 3A – 330 kV double circuit between Bulli Creek and Armidale*	770	1,593	560	3-4 years
Option 3B – 330 kV double circuit line between Braemar and Liddell via Uralla (and establishment of a Uralla 330 kV substation)	1,530	2,160	1,505	4-5 years
Option 3C – 330 kV double circuit line between Braemar and Uralla, 500 kV single circuits between Uralla and Wollar and between Uralla and Bayswater (and establishment of Uralla 500/330 kV substation)	1,695	2,540	2,039	5-6 years
High Voltage Direct Current options				
Option 4A – HVDC back-to-back	1,195	1,780	825	2-3 years
Option 4B – HVDC between Mudgeeraba and Lismore**	765	1,190[33]	600	3-4 years
Option 4C – HVDC between Western Downs and Bayswater**	2,590	2,990	2,100	4-5 years
A grid-connected battery system				
Option 5 - Battery energy storage system	1,135	1,635	1,000	1-3 years

** Option 1A is the ISP recommended Group 1 investment and Option 3A is the ISP recommended Group 2 investment. The transfer capacities and cost estimates for these options will be refined in the PADR.*
*** Power transfer capacities are defined as the sum of both the HVAC interconnector and for the new HVDC option.*

[31] The transfer capacities shown in this table are indicative for one operating state only (daytime, medium demand) and serve to summarise the notional differences between options.

[32] All cost estimates are to be treated as indicative at this stage and TransGrid and Powerlink will further refine these estimates as part of the PADR.

[33] Limited by Armidale – Tamworth 330kV summer noon thermal ratings. Variant options will be investigated with uprating upstream limitations and reported in the PADR

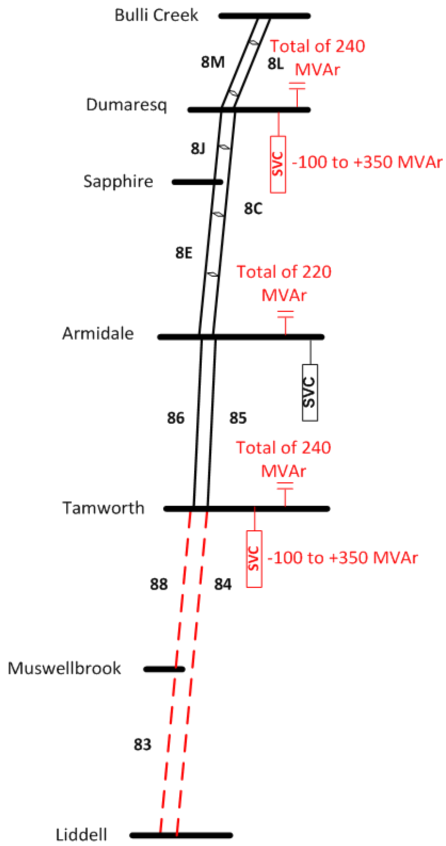
TransGrid and Powerlink note that a 'first-pass' screening process will be applied to the above options, and any others identified, in preparing a PADR. In particular, while each credible option will be modelled as part of the PADR, it is expected that the initial list will be refined based on this modelling and that only a subset of these options will be progressed at the PADR stage, based on estimated net market benefits. As part of this process we will also investigate combinations of options to provide greater expected net market benefits than separately.

In addition, TransGrid and Powerlink are also intending to further investigate the routing of the options. As an example, there may be opportunity to design the new interconnector options so they connect geographically diverse sources of renewable generation beyond the capacities of the existing lines, which may provide further incremental net market benefits.

The remainder of this section provides further detail on each of these options. It also outlines a number of options that have been considered but not progressed (and the reasons why). Section 4 outlines the technical characteristics that a non-network option would need to possess in order to assist with meeting the identified need for this RIT-T.

We have included a network diagram for each option, which shows the existing network configuration (in black) with works and new elements for each option (in red).

3.1 Option 1A – Uprate Liddell to Tamworth lines and install dynamic reactive support



Option 1A involves incremental investments to the existing network to increase transfer capacity in the short-term. This option is the same as that recommended in the ISP for Group 1.

The two key components of Option 1A are:

- uprating the Liddell to Tamworth lines; and
- installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks.

The first component targets northerly QNI thermal limitations only by uprating Line 83, 84 and 88 which are the Liddell to Tamworth via Muswellbrook circuits shown earlier in Figure 5. These lines would be uprated from the existing design operating temperature of 85°C to 120°C.

The second component targets both northerly and southerly QNI stability limits by installing dynamic reactive support at both the Tamworth and Dumaresq 330 kV substations, and installing additional 330 kV shunt connected capacitor banks at Tamworth, Armidale and Dumaresq 330 kV substations.

Alternative options for plant providing a dynamic source of reactive support include:

- Static VAr Compensator (SVC);
- Static synchronous compensator (STATCOM); and
- Synchronous condenser.

These types of plant offer different attributes with varying degrees of benefits. For example:

- synchronous condensers provide system strength and inertia in addition to dynamic reactive power. These properties provide further system resilience and lower connection costs for proponents of invertor connected generators (such as wind and solar PV); while
- a SVC, on the other hand, is generally a less expensive source of dynamic reactive power but does not provide system strength or inertia.

For the purposes of describing this option in this PSCR a SVC is considered as the source of the dynamic reactive support at both Tamworth and Dumaresq. However, TransGrid and Powerlink are continuing to assess which technology is considered optimal and will report the outcome in the PADR.

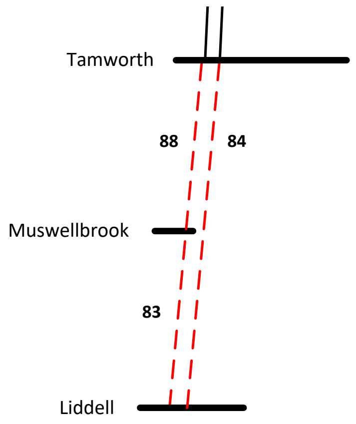
Table 4 presents a qualitative assessment of Option 1A.

Table 4 Qualitative assessment of Option 1A

Advantages	• Utilisation of existing easements • Alternative dynamic plant can provide additional benefits (i.e., system strength, inertia)
Disadvantages	• Involves lengthy outages with low inter regional limits during construction period • Higher consequences of non-credible loss of QNI double circuit (greater transfer without additional circuits)

The estimated capital cost of Option 1A is $142 million. Delivery is expected to take 2-3 years, with commissioning possible in late 2022, subject to obtaining necessary environmental and development approvals.

3.2 Option 1B – Uprate Liddell to Tamworth lines only



Option 1B involves only the first component of Option 1A, i.e., uprating the Liddell to Tamworth lines (Line 83, 84 and 88), as described in the section above. The network configuration does not change under this option and the network remains the same as that shown earlier in Figure 5.

Option 1B has been included as an alternative to Option 1A and explicitly investigates the expected net market benefits of just doing the line uprating component.

Table 5 presents a qualitative assessment of Option 1B.

Table 5 Qualitative assessment of Option 1B

Advantages	• Utilisation of existing easements
Disadvantages	• Involves lengthy outages with low inter regional limits during construction period • Only addresses northerly power transfer limits • Only addresses one mode of failure (thermal)

The estimated capital cost of Option 1B is $28 million. Delivery is expected to take 2-3 years, with commissioning possible in 2022, subject to obtaining necessary environmental and development approvals.

3.3 Option 1C - Install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks

Option 1C involves only the second component of Option 1A, i.e., installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks, as described in section 3.1 above. The network configuration is the same as that shown in Section 3.1 above.

As with Option 1B, Option 1C has been included as an alternative to Option 1A and explicitly investigates the expected net market benefits of just doing the new dynamic reactive support at Tamworth and Dumaresq and the shunt capacitor banks.

Table 6 presents a qualitative assessment of Option 1.

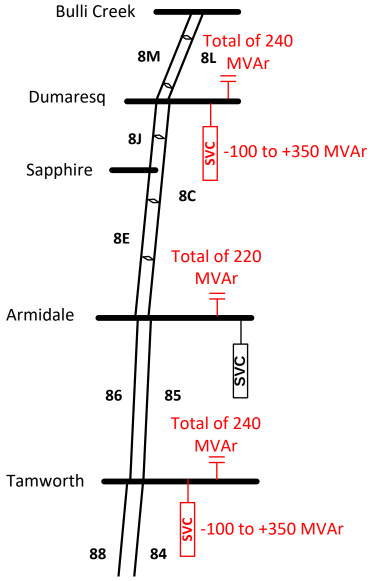


Table 6 Qualitative assessment of Option 1C

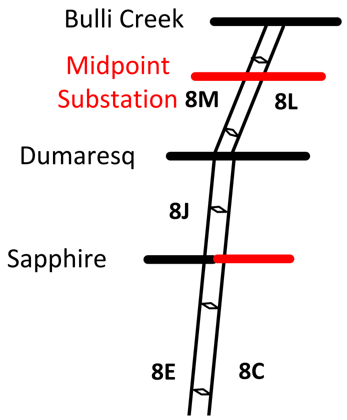
Advantages	• No easements/line work (i.e., fast delivery) • Does not involve lengthy outages • Alternative dynamic plant can provide additional benefits (i.e., system strength, inertia)
Disadvantages	• Does not significantly raise thermal limit (only by reduction in reactive power transfer) • Higher consequences of non-credible loss of QNI double circuit (greater transfer without additional circuits)

The estimated capital cost of Option 1C is $114 million. Delivery is expected to take 2-3 years, with commissioning possible in 2022, subject to obtaining necessary environmental and development approvals.

3.4 Option 1D – Sapphire substation cut into line 8C and a mid-point switching station between Dumaresq and Bulli Creek

Option 1D involves cutting in the Sapphire substation to Line 8C and constructing a new switching station. In particular, Option 1D involves:

- cutting line 8C (Armidale – Dumaresq 330 kV) into the existing Sapphire Substation; and
- establishing a new mid-point switching station between Bulli Creek – Dumaresq 330 kV by cutting in 8M and 8L.



This targets only southerly QNI stability and thermal limitations and has been included as a potentially cheaper alternative to installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (i.e., the second component included in Option 1A and Option 1C).

Sectionalising these lines increases southerly transfer capability by reducing the impact of the southerly stability critical contingency. The mid-point switching station reduces the transmission impedance following the loss of the Sapphire – Armidale line or a circuit between Dumaresq and Bulli Creek substations. This option alone does not increase thermal rating limitations in the system.

Table 7 presents a qualitative assessment of Option 1D.

Table 7 Qualitative assessment of Option 1D

Advantages	• Expected lowest cost network option increasing southern transfers • Targets southerly critical contingencies • No easements/line work (faster delivery) • Does not involve lengthy outages
Disadvantages	• Only addresses southerly power transfer limits • May not provide an advantage when combined with another option • Higher consequences of non-credible loss of QNI double circuit (greater transfer without additional circuits)

The estimated capital cost of Option 1D is $45 million. Delivery is expected to take 1-2 years, with commissioning possible in 2022, subject to obtaining necessary environmental and development approvals.

3.5 Option 2 – A new single-circuit 330 kV line from NSW to Queensland

Option 2 is an option for delivering the longer-term Group 2 increase in transfer capacity outlined in the ISP.

It does this by targeting both northerly and southerly QNI stability and thermal limits by constructing a 330 kV single circuit transmission line between Braemar and Liddell substations.

The high-level scope of this option includes:

- Construct five single circuit 330 kV transmission lines:
  - Liddell – Tamworth 330 kV substation;
  - Tamworth – Armidale 330 kV substation;
  - Armidale – Dumaresq 330 kV substation;
  - Dumaresq – Bulli Creek 330 kV substation; and
  - Bulli Creek – Braemar 330 kV substation.
- Install a new 1500MVA 330/275kV transformer connecting to the Braemar western 275kV bus.
- Install an SVC at Armidale substation with a range of 120 MVAr inductive to 280 MVAr capacitive at nominal voltage and connected to the respective 330 kV busbars.
- Install 200 MVAr shunt connected capacitor banks at Armidale.
- Install 50 MVAr shunt reactors on each new line section at Liddell, Tamworth, Armidale, Dumaresq, Bulli Creek and Braemar substations.
- Augment the existing substations at Liddell, Tamworth, Armidale, Dumaresq, Bulli Creek and Braemar to accommodate the additional transmission line, transformer, SVC, shunt capacitor and shunt reactor connections.

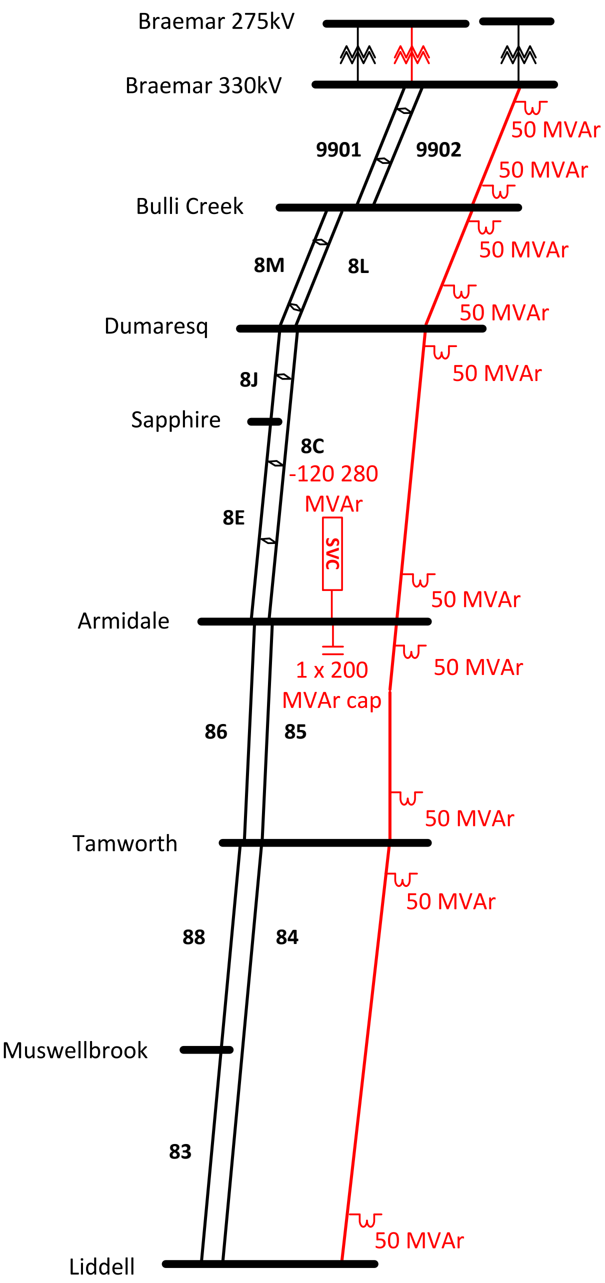


Table 8 presents a qualitative assessment of Option 2.

Table 8 Qualitative assessment of Option 2

Advantages	• Addresses all modes of failure • Additional circuit provides greater resilience during outages • Could be staged to target sections of most benefit • Allows potential unlocking of REZ • Does not involve lengthy outages
Disadvantages	• Low capacity per easement (single circuit) • Lengthy delivery (easement/lines works)

The estimated capital cost of Option 2 is $855 million. Delivery is expected to take 3-4 years, with commissioning possible in 2024, subject to obtaining necessary environmental and development approvals.

3.6 Option 3A – 330 kV double circuit line between Bulli Creek and Armidale

Option 3A is an option for delivering the longer-term Group 2 increase in transfer capacity outlined in the ISP. It does this by targeting both northerly and southerly QNI stability limits by constructing a 330 kV double circuit transmission line between Bulli Creek and Armidale substations.

Option 3A is the 2018 ISP recommended Group 2 option.

The high-level scope includes:

- Construct two double circuit 330 kV transmission lines:
  - Armidale – Dumaresq 330 kV substation; and
  - Dumaresq – Bulli Creek 330 kV substation.
- Install 50 MVAr shunt reactors on each new line section at Armidale, Dumaresq and Bulli Creek substations.
- Augment the existing substations at Armidale, Dumaresq and Bulli Creek to accommodate the additional transmission line and shunt reactor connections.
- Uprate Liddell to Tamworth transmission lines

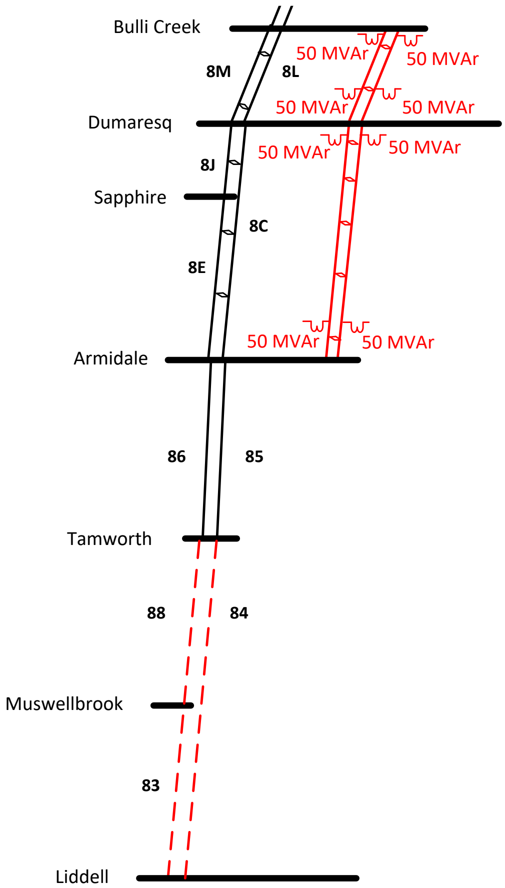


Table 9 presents a qualitative assessment of Option 3A.

Table 9 Qualitative assessment of Option 3A

Advantages	• Initial stage of a greater capacity ultimate solution • High capacity per easement (double circuit) • Could be delivered in stages (one side strung) increasing option value • Additional circuit provides greater resilience during outages • Allows potential unlocking of REZ • Does not involve lengthy outages
Disadvantages	• Only addresses a problem partway (next limit is not too much higher) • Lengthy delivery (easement/lines works) • High cost to limit increase ratio

The estimated capital cost of Option 3A is $560 million. Delivery is expected to take 3-4 years, with commissioning possible in 2024, subject to obtaining necessary environmental and development approvals.

3.7 Option 3B – 330 kV double circuit line between Braemar and Liddell via Uralla

Option 3B is an option for delivering the longer-term Group 2 increase in transfer capacity outlined in the ISP. It does this by targeting both northerly and southerly QNI stability and thermal limits by establishing Uralla 330kV substation and constructing a 330 kV double circuit line between Liddell and Braemar substations. Option 3B is also expected to open up capacity for more new renewable energy connections in northern New South Wales and southern Queensland than Option 3A.

The high-level scope includes:

- Establish a new 330 kV substation at Uralla cutting into existing line 85 and 86;
- Augment the existing Sapphire substation to cut in line 8C (Armidale – Dumaresq).
- Construct five double circuit 330 kV transmission lines:
    - Liddell – Uralla 330kV substation;
    - Uralla – Sapphire 330kV substation;
    - Sapphire – Dumaresq 330kV substation;
    - Dumaresq – Bulli Creek 330kV substation; and
    - Bulli Creek – Braemar 330 kV substation.
- Install a new 1500MVA 330/275kV transformer connecting to the Braemar western 275kV bus.
- Install an SVC at the new Uralla substation with a range of 100 MVAr inductive to 350 MVAr capacitive at nominal voltage.
- Install 2 x 200 MVAr shunt connected capacitor banks at Uralla and Dumaresq 330kV substations.
- Install 50 MVAr shunt reactors on each new line section at Liddell, Uralla, Sapphire, Dumaresq, Bulli Creek and Braemar substations.
- Augment the existing substations at Liddell, Sapphire, Dumaresq, Bulli Creek and Braemar to accommodate the new transmission line, transformer, SVC, shunt capacitor and shunt reactor connections.

The network diagram for Option 3B is shown below.

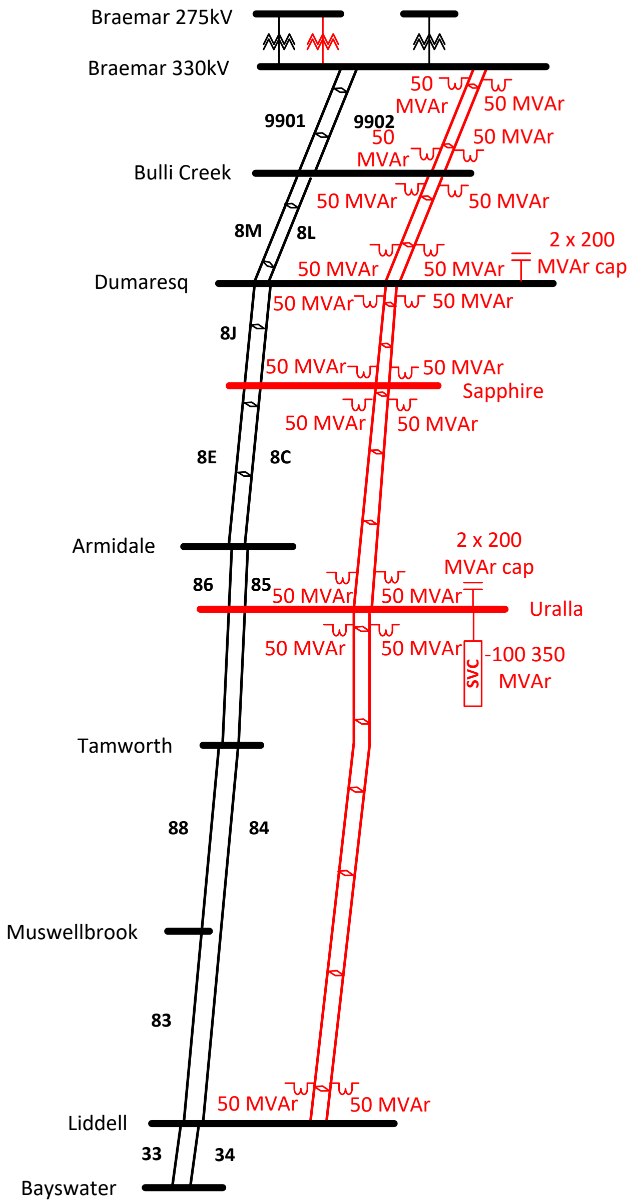


Table 10 presents a qualitative assessment of Option 3B.

Table 10 Qualitative assessment of Option 3B

Advantages	• High inter-regional capacity • High capacity per easement (double circuit) • Could be delivered in stages (one side strung) increasing option value • Additional circuit provides greater resilience during outages • Allows potential unlocking of REZ • Does not involve lengthy outages
Disadvantages	• Lengthy delivery (easement/lines works) • Network south of Liddell and north of Halys becomes limiting

The estimated capital cost of Option 3B is $1,505 million. Delivery is expected to take 4-5 years, with commissioning possible in 2025, subject to obtaining necessary environmental and development approvals.

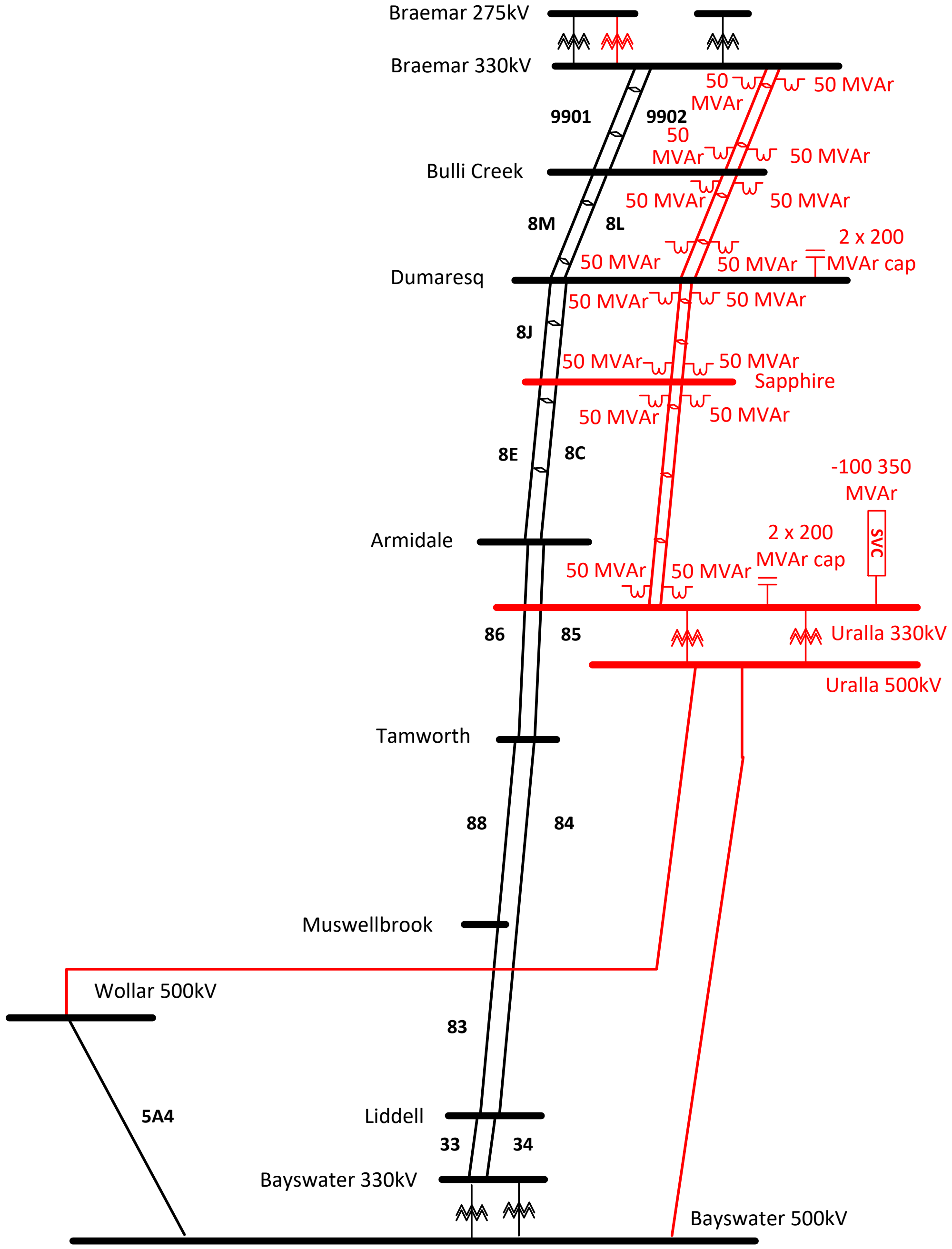
3.8 Option 3C – 330 kV double circuit line between Braemar and Uralla, 500 kV single circuits between Uralla and Wollar and between Uralla and Bayswater

Option 3C is an option for delivering the longer-term Group 2 increase in transfer capacity outlined in the ISP. It does this by targeting both northerly and southerly QNI stability and thermal limits by establishing Uralla 500/330 kV substation with 2 x 500/330 kV 1,500 MVA transformers, constructing a 330 kV double circuit transmission line between Braemar and Uralla substations and 500 kV single circuits between Uralla and Wollar and between Uralla and Bayswater. Option 3C is also expected to open up capacity for more new renewable energy connections in northern New South Wales and southern Queensland than Option 3A.

The high-level scope includes:

- Establish a new 500/330 kV substation at Uralla cutting into existing line 85 and 86 with 2 x 500/330 kV 1,500 MVA transformers.
- Augment the existing Sapphire substation to cut in line 8C (Armidale – Dumaresq).
- Construct four double circuit 330 kV transmission lines:
  - Uralla – Sapphire 330kV substation;
  - Sapphire – Dumaresq 330kV substation;
  - Dumaresq – Bulli Creek 330kV substation; and
  - Bulli Creek – Braemar 330 kV substation.
- Construct two single circuit 500 kV transmission lines:
  - Wollar – Uralla 500kV substation; and
  - Bayswater – Uralla 500kV substation.
- Install a new 1500MVA 330/275kV transformer connecting to the Braemar western 275kV bus.
- Install an SVC at the new Uralla substation with a range of 100 MVAr inductive to 350 MVAr capacitive at nominal voltage.
- Install 2 x 200 MVAr shunt connected capacitor banks at Uralla and Dumaresq 330kV substations.
- Install 50 MVAr shunt reactors on each new line section at Uralla, Sapphire, Dumaresq, Bulli Creek and Braemar substations.
- Augment the existing substations at Wollar, Bayswater, Sapphire, Dumaresq, Bulli Creek and Braemar to accommodate the additional transmission line, transformer, SVC, shunt capacitor and shunt reactor connections.

The network diagram for Option 3C is shown below.



The shunt connected capacitor banks at the Uralla and Dumaresq 330 kV substations are the same as for Option 3B, detailed earlier.

Table 11 presents a qualitative assessment of Option 3C.

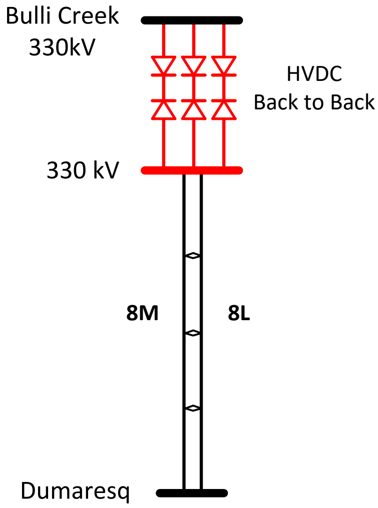
Table 11 Qualitative assessment of Option 3C

Advantages	• Highest inter-regional capacity HVAC solution connecting to a strong 500 kV network • 500 kV has lower transmission losses than lower voltage options • High capacity per easement up to Uralla (double circuit) • Could be delivered in stages (one side strung) increasing option value • Additional circuit provides greater resilience during outages • Allows potential unlocking of REZ • Does not involve lengthy outages
Disadvantages	• Lengthy delivery (easement/lines works) • Network north of Halys becomes limiting

The estimated capital cost of Option 3C is $2,039 million. Delivery is expected to take 5-6 years, with commissioning possible in 2026, subject to obtaining necessary environmental and development approvals.

3.9 Option 4A – HVDC back-to-back

Option 4A is an option for delivering the longer-term Group 2 increase in transfer capacity outlined in the ISP and builds on the ISP suggestion that HVDC options should be assessed in the RIT-T. It does this by targeting both northerly and southerly QNI stability and thermal limits by installing 2,000MW continuously rated back-to-back HVDC converters at Bulli Creek substation.



This option decouples the Queensland AC system from the rest of the NEM. For a contingency which would otherwise affect the QNI corridor, the converter station can quickly run back transfers to ensure the system lands in a satisfactory state.

The high-level scope includes:

- Install 3 x 666 MVA HVDC back-to-back converters with 5 per cent overload capability for 15 minutes.
- Construct a second 330kV bus at Bulli Creek 330 kV substation.
- System Integrity Protection Scheme (SIPS) to control the transfer through the converters depending on critical contingencies on the AC QNI corridor.
- Augment the existing Bulli Creek substation to accommodate the converter and transmission line connections.

The estimated capital cost of Option 4A is $825 million. While the capital costs of HVDC options are considered to be more expensive generally than HVAC options (on a per additional MW of transfer capacity improvement basis), the ongoing operating costs are expected to be lower. TransGrid and Powerlink are continuing to investigate the annual operating costs of every option and will report on these in the PADR.

Table 12 presents a qualitative assessment of Option 4A.

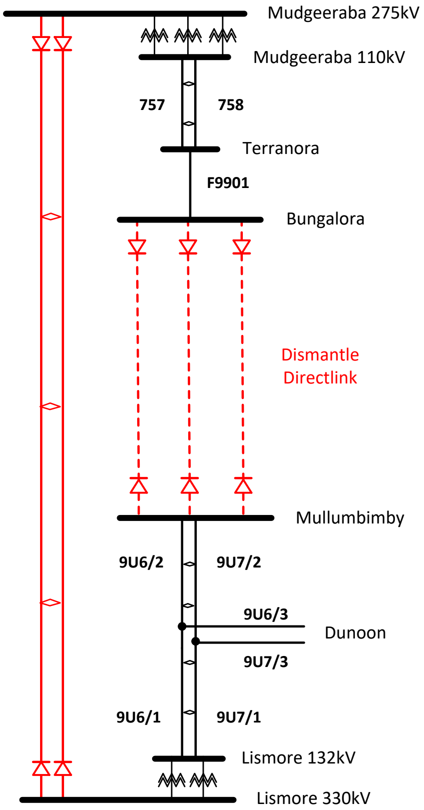
Table 12 Qualitative assessment of Option 4A

Advantages	• Faster delivery (substation works only) • High utilisation of existing easements
Disadvantages	• Heavy reliance on SIPs increases complexity • Frequency impacts adding uncertainty and cost (in FCAS market) • Very high consequences of non-credible loss of QNI double circuit (greater transfers without additional circuits) • May require additional dynamic reactive plant to reach thermal limits

Delivery is expected to take 2-3 years, with commissioning possible in 2023, subject to obtaining necessary environmental and development approvals.

3.10 Option 4B – HVDC between Mudgeeraba and Lismore

Option 4B is a second HVDC option for delivering the longer-term Group 2 increase in transfer capacity outlined in the ISP. It does this by targeting both northerly and southerly QNI stability limits by upgrading and extending the existing 180 MW Directlink HVDC connection between Bungalora and Mullumbimby into a 600 MW HVDC connection between Mudgeeraba 275kV and Lismore 330kV substations.



The high-level scope includes:

- Dismantle the Bungalora and Mullumbimby Directlink converter stations.
- Extend cable to Mudgeeraba 275 kV and Lismore 330 kV substations.
- Install 2 x 300MVA converter stations at Mudgeeraba and Lismore 330kV substation.
- System Integrity Protection Scheme (SIPS) to control the transfer depending on critical contingencies feeding the Gold Coast and Lismore areas.
- Augment the existing substations at Lismore and Mudgeeraba to accommodate the converter connections.

Table 13 presents a qualitative assessment of Option 4B.

Table 13 Qualitative assessment of Option 4B

Advantages	• Good use of existing easements
Disadvantages	• Network south of Armidale becomes limiting • High cost to limit improvement ratio

The estimated capital cost of Option 4B is $600 million. Delivery is expected to take 3-4 years, with commissioning possible in 2024, subject to obtaining necessary environmental and development approvals.

3.11 Option 4C – HVDC between Western Downs and Bayswater

Option 4C is a third option for delivering the longer-term Group 2 increase in transfer capacity outlined in the ISP. It does this by targeting both northerly and southerly QNI stability and thermal limits by installing a 2,000 MW HVDC connection between Western Downs and Bayswater via Bollon.

The high-level scope includes:

- Construct 1,000 km quad sulphur 500kV transmission line between Western Downs and Bayswater via Bollon, utilising guyed cross-rope where appropriate
- Install 2 x 1,000MW HVDC VSC bipole half-bridge converter stations at both Western Downs and Bayswater substations
- Install dynamic reactive plant at each of Tamworth and Dumaresq substations.
- Install capacitor banks at Tamworth, Armidale and Dumaresq substations.
- System Integrity Protection Scheme (SIPS) to control the transfer through the converters depending on the contingency.

Table 14 presents a qualitative assessment of Option 4C.

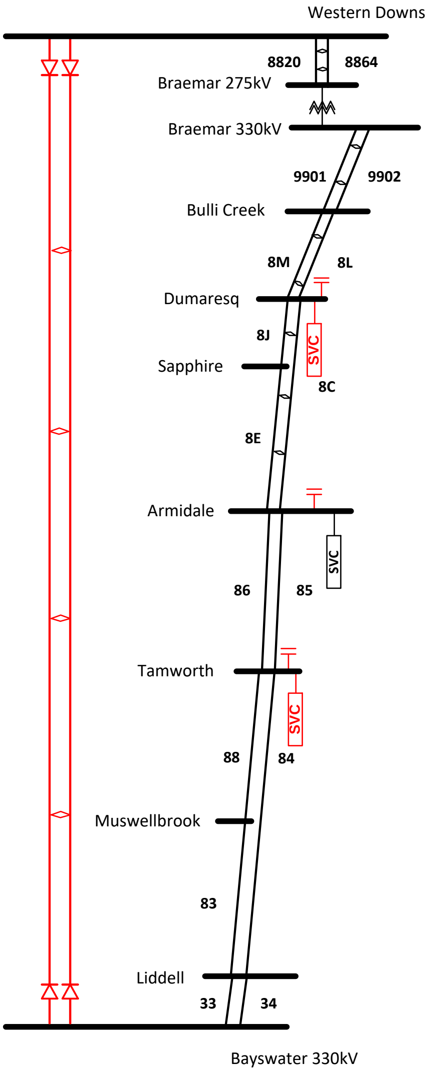


Table 14 Qualitative assessment of Option 4C

Advantages	• Addresses all modes of failure (stability and thermal) • Lowest incremental cost for increased distance • A variant of this option could also address intra-regional issues by moving the northern connection/converter to Stanwell or Calvale • Initial stage of future high capacity backbone
Disadvantages	• High contingency size (loss of 1,000 MW for a fault on a HVDC circuit) • Connection of renewable energy zones to HVDC is more complex than to HVAC systems with a higher cost • Requires additional dynamic reactive plant to reach thermal limits in existing HVAC lines • Reliance on SIPs increases complexity • Lengthy delivery (easement/lines works)

The estimated capital cost of Option 4C is $2,100 million. Delivery is expected to take 4-5 years, with commissioning possible in 2025, subject to obtaining necessary environmental and development approvals.

3.12 Option 5 – Battery energy storage system

This option targets both northerly and southerly QNI stability and thermal limits by installing a battery energy storage system (BESS), controlled by a System Integrity Protection Scheme (SIPS), at two ends of QNI corridor.

The operation of BESS will mimic a "virtual transmission line" following a transmission line contingency.

The high-level scope includes:

- Install a BESS 600 MW 4C[34] at Halys and Liddell 330 kV substations.
- System Integrity Protection Scheme (SIPS) to control power targets depending on critical contingencies on the QNI corridor.

The estimated capital cost of Option 5 is $1,000 million. As noted for the HVDC options, the ongoing operating costs of a BESS are expected to be lower than the HVAC options. TransGrid and Powerlink are continuing to investigate the annual operating costs of every option and will report on these in the PADR.

Table 15 presents a qualitative assessment of Option 5.

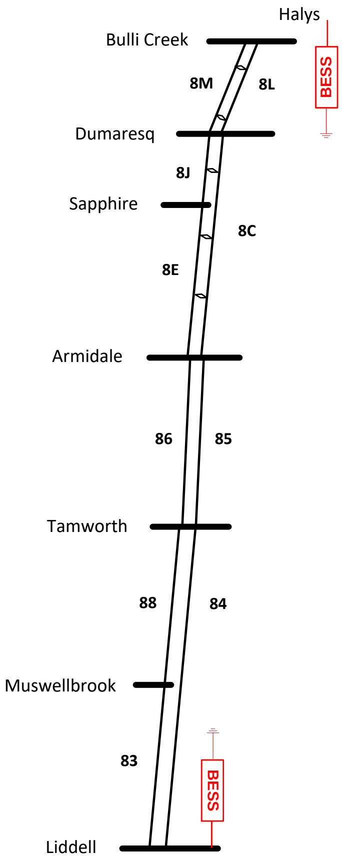


Table 15 Qualitative assessment of Option 5

Advantages	• Modular solution. Could be distributed to increase/target intra-regional limitations • Can provide additional services (such as frequency control) • Faster delivery • Does not involve lengthy outages
Disadvantages	• High uncertainty in lifetime costs • Heavy reliance on SIPs increases complexity

Delivery is expected to take 1-3 years, with commissioning possible in 2022, subject to obtaining necessary environmental and development approvals.

[34] A battery capable of discharging the total stored energy within ¼ of an hour.

3.13 Options considered but not progressed

TransGrid and Powerlink have also considered a range of other potential credible options but have not progressed these on the grounds that they are not considered feasible, and therefore are not considered to be credible options. A summary of each is provided in Table 16.

Upgrading protection systems and a braking resistor in the Hunter Valley (both outlined below) were also examined and ruled out as part of the 2014 QNI RIT-T.[35] In particular, a first pass assessment at the time, examining the economic viability of additional QNI upgrade options under a limited set of market development scenarios, concluded that these network options were not considered to be economically viable, and as such were not considered further.

Table 16 Options considered but not progressed

Option	Overview	Reason(s) it has not been progressed
The use of series compensation	Installation of series capacitors across the Bulli Creek to Dumaresq and Dumaresq to Armidale 330 kV	The use of series compensation would likely involve costs similar to other options (namely, the incremental options outlined above) and provide similar increases in transfer capacity. However, series compensation comes with increased technical risk that other options do not have. Specifically, as a result of series capacitors being installed on the QNI, there is a potential for sub-synchronous resonance to occur with some nearby thermal generators, or any wind farm generators that maybe developed nearby in the future. This option is therefore considered technically inferior and is proposed to not be considered further as part of this RIT-T.
Upgrading protection systems	A protection system upgrade option, involving a combination of protection relay upgrades and circuit breaker replacements on Line 83 and 88 to reduce the fault clearance time	This option is not expected to materially change the critical contingencies that set the transfer capability across QNI for a large proportion of the time. This option is therefore not considered technically feasible.

35 QNI Upgrade Project Assessment Conclusions Report, March 2014, p. 36 https://www.powerlink.com.au/Network/Network_Planning_and_Development/Documents/QNI_Upgrade_Project_Assessment_Conclusions_Report_March_2014.aspx

Option	Overview	Reason(s) it has not been progressed
A braking resistor in the Hunter Valley	A Hunter Valley NSW braking resistor option, involving the installation of a 500 MW braking resistor connected to either the Liddell or Bayswater Power Station 330 kV busbar	This option would not provide any improvement to the Queensland to NSW thermal capability, voltage and transient stabilities. In addition, Liddell is expected to retire in 2022 and so the braking resistor arrangement would also cease to apply. This option is therefore not considered technically feasible.

3.14 Material inter-network impact

TransGrid and Powerlink have considered whether the credible options above are expected to have a material inter-network impact.[36] A 'material inter-network impact' is defined in the NER as:

> *"A material impact on another Transmission Network Service Provider's network, which may include (without limitation): (a) the imposition of power transfer constraints within another Transmission Network Service Provider's network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network."*

The majority of the credible options outlined above are interconnectors and will therefore have a material inter-network impact.

We will request AEMO to produce an augmentation technical report in relation to the options being considered in this RIT-T.[37] As part of the augmentation technical report, AEMO is required by the NER to:[38]

- consult with, and take into account the recommendations of, the jurisdictional planning representatives in relation to the proposed augmentation; and
- make a determination as to: (i) the performance requirements for the equipment to be connected; and (ii) the extent and cost of augmentations and changes to all affected transmission networks; and (iii) the possible material effect of the new connection on the network power transfer capability including that of other transmission networks.

We intend to publish the augmentation technical report with the PACR.[39]

[36] NER clause 5.16.4(b)(6)(ii).

[37] NER clause 5.21(d)(1)-(3).

[38] NER 5.16.4 (k)(9)(iii).

[39] As required by NER 5.16.4 (k)(9)(iii).

4. Non-network option information

This section describes the technical characteristics that a non-network option would be required to deliver in order to address the identified need.[40]

TransGrid and Powerlink have outlined below how non-network technologies can contribute to meeting the identified need of relieving existing and forecast congestion on the transmission network between New South Wales and Queensland over the short and medium term. We also present a number of potential technologies that could assist.

In particular, we set out both:

- general information on how non-network options can assist with increasing transfer capacity (section 4.1); and
- specific information on the use of a potential Wide Area System Integrity Protection Scheme (section 4.2).

Proponents of non-network options are encouraged to make submissions on any non-network option they believe can address, or contribute to, the identified need.

We encourage proponents to reach out and contact us as soon as practicable about potential solutions, ahead of preparing a formal submission. Overall, this process will enable these options to be assessed alongside the network options in the PADR.

The final part of this section presents the form of information to be provided by non-network proponents looking to assist with relieving existing and forecast congestion on the transmission network between New South Wales and Queensland.

As outlined in section 2.4.3, Powerlink is continuing to investigate the impact on, and interaction with, the QNI transfer limits from intra-network constraints (including in central Queensland). Should any material constraints emerge as part of this, Powerlink will publish additional information on these constraints, any potential network solutions to addressing them and explicitly call for responses from non-network proponents.

4.1 Non-network options

At a high-level, credible non-network options for assisting with relieving existing and forecast congestion on the transmission network between New South Wales and Queensland in-line with the ISP findings need to either:

- provide estimated net market benefits in-line with those estimated for the credible network options; or
- be able to be coupled with a network option in order to increase its estimated net market benefit overall.

TransGrid and Powerlink note that the key drivers of market benefits for the network options, as have been described above, are as follows:

- In the short-term (i.e., in-line with ‘Group 1’ of the ISP):
  - defer the need for new gas fired generation in New South Wales to meet demand once Liddell retires in 2022; and
  - facilitate more efficient generation sharing between New South Wales and Queensland;
- Over the medium-term (i.e., in-line with ‘Group 2’ of the ISP):

[40] In accordance with NER clause 5.16.4(b)(3).

- deliver fuel cost savings and capital deferral by allowing greater use of coal-fired generation in Queensland, and renewable energy developed to achieve the QRET; and
- assist the nation meet carbon emission and renewable energy targets at lowest long run cost.

As outlined in section 2, a reduced need for new investment in generating plant, or a deferral of generation investment, represents a key market benefit under the RIT-T – as does the facilitating the substitution of high-fuel cost plant with low-fuel cost plant, which lowers the overall cost of dispatch and reduce aggregate generator fuel costs in the NEM.

Greater transfer capacity within the NEM would also allow renewable energy in these regions to assist the nation meet carbon emission and renewable energy targets at lowest long run cost. Opening up additional geographical areas of the NEM for renewable investment will drive diversification of renewable energy and lead to less volatility in output as a result of local weather effects. Within the context of the RIT-T assessment, greater output from renewable generation can be expected to primarily deliver the following classes of market benefit:

- further reductions in total dispatch costs (including fuel costs), by enabling low cost renewable generation to displace higher cost conventional generation; and
- reduced generation investment costs, resulting from more efficient investment and retirement decisions, due to high quality wind, solar and pumped-hydro generation being able to locate in the vicinity of QNI, compared to other inferior locations.

To achieve similar categories of market benefits, in the first instance non-network options would need to be able to reduce load in New South Wales and Queensland at peak demand times to the extent that they reduce the need for expensive peaking generators to be dispatched and/or defer the need for further investment in peaking plant.

TransGrid and Powerlink have set out a number of potential technologies that could assist with providing the key categories of market benefit expected under this RIT-T in Table 17.

Given the nature of the identified need (and the yet to be quantified estimated market benefits from expanding transfer capacity), as well as a desire to not be prescriptive at this early stage of the RIT-T regarding the role of non-network options, we have not specified minimum quantities and operating profiles for these solutions.

We are interested to hear from parties regarding the potential for non-network options to satisfy, or contribute to satisfying, the identified need, and from potential proponents of such non-network options.

Table 17 How non-network technologies can assist in delivering key market benefits

	Reducing/deferring the generation cost	Assistance with lowering generator fuel consumption	Facilitating the connection of high-quality renewables generation
Overview of how non-network technologies may be able to assist with providing each key market benefit	A non-network option would need to defer the need for further generation development in NSW or QLD	A non-network option would need to be able to reduce load in NSW or QLD at peak demand times so as to reduce the need for peaking or other generators to be dispatched, or to provide a fast response in the event of contingencies, in order to relieve the current operational constraints on the interconnector	A non-network option would need to open up additional high-quality geographical areas of the NEM for renewable investment, which will drive diversification of renewable energy and lower carbon emissions
Possible technologies			
Peak load reduction in either QLD or NSW	✓	-	-
Shifting of load to alternative time periods	✓	✓	
Energy storage that uses any surplus or low cost generation to be released at appropriate times	✓	✓	✓
Improved utilisation of existing generating plant	✓	-	-
Pre-emptive load reduction to reduce the loading on QNI at constraining time	-	✓	-
Post-contingent load reduction and generator shedding to counteract the stability limitations on QNI	-	✓ (These actions may need to be very high speed (within a few cycles of a contingency))	-
Improve the system strength to accommodate more renewable generation	-	-	✓

4.2 Information regarding a potential Wide Area System Integrity Protection Scheme

TransGrid and Powerlink are interested in understanding the potential to leverage flexibility in generation and demand to extend the capacity of QNI. This could operate in a similar manner to proposed network Option 5, but utilising generation and demand response in place of new batteries.

In particular, we consider that Queensland to New South Wales transfer capacity could be increased if, immediately following, a:

- critical network contingency, generation could be tripped or runback in Queensland, and a corresponding amount of load could be tripped or run back in New South Wales;
- critical Queensland load trip, a corresponding amount of generation could be tripped or runback in Queensland; or
- critical New South Wales generation trip, a corresponding amount of load could be tripped or runback in New South Wales.

Similarly, we consider that New South Wales to Queensland capacity could be increased if, immediately following, a:

- critical network contingency, generation could be tripped or runback in New South Wales, and a corresponding amount of load could be tripped or run back in Queensland; or
- critical Queensland generation trip, a corresponding amount of load could be tripped or runback in Queensland; or
- critical New South Wales load trip, corresponding amount of generation could be tripped or runback in New South Wales.

The tripped or run-back generation and load would need to remain in this state until AEMO is able to re-secure the power system (i.e., within 30 minutes) but would then be free to resume normal operation within the new secure envelope.

For such a Wide Area System Integrity Protection Scheme to function it would require the participation of generators and loads located on either side of QNI – specifically:

- Generators which can be run back very quickly or tripped without adverse consequences
  - this may be particularly applicable to large inverter-connected generators which can operate flexibly; and
  - the level of run-back which could be offered at a specific point in time would be limited by the level at which the generation is operating (i.e. without storage, a solar generator would be unable to provide a runback service overnight).
- Loads which could be run back very quickly or tripped without adverse consequences.
  - it is anticipated that this may be most appropriate for industrial loads that have a high degree of controllability and/or have energy storage incorporated into the process (e.g. heat); and
  - the level of run-back would be limited by the size of the load, and any variations in consumption over time.
- Energy storage such as large-scale battery installations could respond quickly in either direction
  - the capacity to respond would be limited by the headroom between their power capacity and the current level of output, and how much energy is presently stored (i.e. the state-of-charge for a battery).

For all proponents, consideration would also need to be given to how complementary this service has with other ancillary services that it may be providing (e.g. FCAS) during such contingencies.

TransGrid and Powerlink do not consider there to be a particular requirement for the location of participating generators. A reduction of any load located south of QNI will result in the reduction in the south-bound flow across QNI, and the same principle applies to loads located north of QNI and generation on either side of QNI.

However, consideration will need to be given to whether the response could exacerbate constraints elsewhere in the NEM. The risk of additional local constraints limiting participation would generally increase with distance from QNI but would need to be considered on a case by case basis.

The nature of stability limitations that often limit QNI call for a very rapid response, in the order of 200ms from the transmission fault commencing to the completion of the ramping and/or tripping of participants. This would necessitate the use of dedicated fast and secure communications and would likely limit participants to those which are connected at a transmission level to a circuit equipped with fibre-optic ground wire. Even so, it is anticipated that this speed of response may prove challenging for loads.

To facilitate a longer time for response, it may be possible to implement a hybrid network and non-network solution in which supercapacitors respond rapidly to the fault, and progressively hand-over the response to loads over a 5-15 second window.

To facilitate and coordinate the response of multiple participants will require a Wide Area System Integrity Protection Scheme, which may operate as follows:

- proponents would need to advise their ability to respond in real-time (given that this may fluctuate over time);
- the scheme would need to aggregate overall availability of demand and generator response on either side of QNI and calculate the additional capacity that could be securely transferred across QNI – AEMO's market dispatch system would need to be provided this information to enable the additional secure capability to be realised;
- on detection of a monitored contingency event, signals would be initiated requiring the agreed response;
- if ramp-back does not occur within the design timeframe the generator/load would be tripped; and
- the signal would be cleared once AEMO had re-secured the power system (which they are required to do under the NER within 30 minutes) and given permission for participants to resume normal operation – participants may be notified of the possibility to return to normal operation in a staggered fashion over several minutes to minimise subsequent disturbances to the power system.

Compensation would be offered to participants through a combination of availability and operation payments.

It is not expected that the scheme would need to operate very frequently since:

- historical fault rates are low
- even when a fault occurs, power transfers would need to be beyond existing limits to necessitate demand or generator action in order to keep the power system stable;
- the scheme would be designed and operated in a manner to minimise the risk of mal-operation or fails-safely; and
- testing would be needed during commissioning, and periodically thereafter to verify the functionality of the scheme but would be designed and coordinated to minimise its impact.

The impact of being part of such a scheme on participants is expected to be modest. Nevertheless, participants would need to be prepared to reliably respond when called upon to do so.

We consider that such a non-network solution could be considered in conjunction with the network options put forward, could be scaled over time in response to changing market needs and could also be used to address intra-regional limitations.

In order to evaluate the viability of such a scheme, TransGrid and Powerlink call upon interested generators and loads to submit a non-binding expression of interest in response to this PSCR. This information will assist

TransGrid and Powerlink to evaluate the practical and economic viability of such a scheme, and inform how to progress the concept in the PADR.

4.3 Information to be provided by proponents of a non-network option

Table 18 sets out the indicative parameters that we request parties nominate in any response to this PSCR.

We note that we are not initiating a formal tender for non-network solutions at this stage. However, we strongly encourage proponents of potential non-network solutions to make a submission to this PSCR and/or to get in contact with us, as any non-network solutions considered potential options under this RIT-T will require indicative costs and timings to be evaluated alongside the other options in the next stage of this RIT-T assessment (i.e., the PADR).

Should the RIT-T assessment identify a non-network solution(s) as the preferred option then we would seek binding offers from the proponent(s) prior to completing the PACR.

Table 18 Indicative parameters that non-network proponents should provide

	Parameter
1	Organisational information
2	Relevant experience
3	Details of the service, including location of relevant technologies. Technical characteristics, such as: • Detection method • Actuation time • Characteristics of the response • Inertia capability • Scalability of the service • Demonstration of ability to deliver utility scale solution in a reasonable time frame
4	Cost of service, separating capital and operational expenditure
5	Confirmation of timelines in providing the service, i.e., speed of response
6	Indicative establishment charge
7	Indicative standby charges
8	Indicative operational charges
9	Responsibility and liability arising directly or indirectly from the operation or failure of the non-network solution
10	Indicative demonstration of the proponent’s financial viability position

5. Materiality of market benefits

The NER requires that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific category (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option.[41]

The PSCR is required to set out the classes of market benefit that the TNSP considers are not likely to be material for a particular RIT-T assessment.[42]

At this stage, TransGrid and Powerlink consider that all categories of market benefit identified in the RIT-T have the potential to be material with the exception of changes in ancillary services costs and competition benefits. A discussion of these two categories of market benefit is provided below.

TransGrid and Powerlink intend to further investigate as part of the PADR whether there is significant 'option value' associated with investments for increasing the transfer capacity between Queensland and New South Wales. In particular, we intend to investigate whether flexibility can be built into any of the options (e.g., building a new line to 500 kV design but initially operating it at 330 kV) so as to be able to respond to external developments if they arise (e.g., a power station announcing earlier than expected retirement).

5.1 Changes in ancillary service costs

While the cost of Frequency Control Ancillary Services (FCAS) may change as a result of changed generation dispatch patterns and changed generation development following expanded transfer capacity between New South Wales and Queensland, TransGrid and Powerlink consider that FCAS costs are relatively small compared to the total market benefits. It is therefore considered that changes in the cost of FCAS are not likely to be materially different between options and are not considered to be material in the selection of the preferred option.

Moreover, we note that HVDC back-to-back option may have an impact, in terms of uncertainty and cost, in the FCAS market. While it is not expected that this will be material at this stage, we are continuing to investigate the impact this option can be thought to have on ancillary service markets such as FCAS and expect to comment in the PADR should it be material.

There is no expected change to the costs of Network Control Ancillary Services (NCAS), or System Restart Ancillary Services (SRAS) as a result of the options being considered. These costs are therefore not material to the outcome of the RIT-T assessment.

While ancillary service costs make up a relatively small proportion of total energy supply costs currently, this may not be the case going forward as renewable penetration in the NEM increases. However, TransGrid and Powerlink note that there is a large degree of uncertainty around how this may develop and do not consider that any increase in ancillary services costs will be different *between* the credible options considered.

5.2 Competition benefits

Competition benefits under the RIT-T relate to net changes in market benefits arising from the impact of the credible option on the bidding behaviour of market participants in the wholesale market.

While each of the credible options considered addresses network constraints between competing generating centres, TransGrid and Powerlink consider that competition benefits are unlikely to be material and do not

41 NER clause 5.16.1(c)(6).

42 NER clause 5.16.4(b)(6)(iii).

intend to estimate them as part of this RIT-T. This is due to New South Wales and Queensland having multiple generation service providers, and are each connected to the rest of the NEM via three and two interconnectors, respectively.

In addition, the 2014 QNI RIT-T indicated that the inclusion of competition benefits did not affect the identification of the preferred option, i.e., the identification of the top credible option(s) within each scenario was found to be robust to the exclusion of competition benefits.[43]

The calculation of competition benefits also requires substantial additional market modelling (as was found in the 2014 QNI RIT-T). TransGrid and Powerlink consider that this modelling exercise would be disproportionate to any competition benefits that may be identified for this specific RIT-T assessment, particularly the difference *between* options in terms of competition benefits.

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[43] TransGrid & Powerlink, *Development of the Queensland-NSW Interconnector*, Project Assessment Conclusions Report, 13 November 2014, p. 75.

Appendix A Checklist of compliance clauses

This section sets out a compliance checklist which demonstrates the compliance of this PSCR with the requirements of clause 5.16.4(b) of the National Electricity Rules version 113.

Rules clause	Summary of requirements	Relevant section(s) in the PSCR
5.16.4(b)	A RIT-T proponent must prepare a report (the project specification consultation report), which must include:	-
	(1) a description of the identified need;	2
	(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	2.4
	(3) the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction or additional supply; (ii) location; and (iii) operating profile;	4
	(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent NTNDP;	2
	(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alternative transmission options, interconnectors, generation, demand side management, market network services or other network options;	3
	(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.16.1(c)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefits are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	1.3, 3 & 5