Expanding NSW-QLD transmission transfer capacity

Project Assessment Conclusions Report

20 December 2019

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Executive summary

TransGrid and Powerlink have explored options for expanding transfer capacity between New South Wales (NSW) 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.

This analysis builds on the assessment in the 2018 Integrated System Plan (ISP) prepared by the Australian Energy Market Operator (AEMO) and its findings are consistent with the draft 2020 ISP results released by AEMO on 12 December 2019 (which reconfirms the proposed network upgrade and labels it a 'no regret' action).[1] In addition, the 2019 AEMO Electricity Statement of Opportunities (ESOO) reconfirmed the importance of completing an incremental upgrade to the Queensland to NSW Interconnector (QNI), as well as a minor upgrade of VNI,[2] ahead of the forecast closure of Liddell Power Station, stating that the upgrades will improve the supply-demand balance in NSW and reduce the likelihood of unserved energy.[3]

The Regulatory Investment Test for Transmission (RIT-T)[4] has been applied to this identified need based on net market benefits, rather than reliability corrective action. Reliability of supply has been considered as one class of market benefits in the overall benefits assessment. This Project Assessment Conclusions Report (PACR) has been prepared as the final formal document in the 'expanding NSW-QLD transmission transfer capacity' RIT-T process and follows the Project Assessment Draft Report (PADR) released in September 2019 and the Project Specification Consultation Report (PSCR) released in November 2018.

This PACR focusses on options for increasing transfer capacity between NSW and Queensland in the near-term, consistent with the assessment of the 'Group 1' QNI expansion in the 2018 ISP and the 'QNI minor' upgrade in the draft 2020 ISP, as well as guidance from the Australian Energy Regulator (AER).[5] This near-term focus ensures that the consideration of medium-term options (i.e., 'Group 2' QNI expansion in the 2018 ISP and 'QNI Medium' in the draft 2020 ISP) does not delay the consideration of near-term options required to ensure the greatest net benefits to NEM participants, whilst increasing transmission transfer capacity, particularly in light of the forecast closure of Liddell Power Station over 2022 and 2023.

The medium-term options included in the PSCR will be assessed as part of a separate RIT-T in the future. This RIT-T's PADR is expected to be published by 10 December 2021 at the latest, in-line with the draft 2020 ISP recommendations.[6]

Overview

The PACR continues to find that the preferred option[7] is expected to deliver significant net benefits associated with expanding transfer capacity between NSW and Queensland in the near-term. This aligns with both the 2018 ISP recommendations and the draft 2020 ISP recommendations.

It finds that uprating the Liddell to Tamworth lines and installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks delivers the greatest expected net benefits of all options considered and is the 'preferred option' as part of this RIT-T.

The analysis shows that the preferred option is expected to:

1 AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, p. 50.

2 'VNI minor' is the proposed incremental increase in transmission transfer capacity between Victoria and New South Wales.

3 AEMO, *2019 Electricity Statement of Opportunities*, August 2019, pp.4 & 93.

4 The Regulatory Investment Test for Transmission (RIT-T) is the economic cost benefit test that is overseen by the AER and applies to all major network investments in the NEM.

5 AER, *Queensland-NSW Interconnector RIT-T guidance notice and engagement process*, available at: https://www.aer.gov.au/communication/queensland-nsw-interconnector-rit-t-guidance-notice-and-engagement-process

6 AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, p. 67.

7 The preferred option is defined as the option that maximises net market benefits under the RIT-T framework.

- deliver approximately $170 million in net benefits over the assessment period, which includes significant wholesale market cost savings that will put downward pressure on electricity prices with flow-on benefits to customers;
- reduce the need for new generation and large-scale storage in New South Wales to meet demand following Liddell Power Station's forecast retirement over 2022 and 2023;
- lower the aggregate generator fuel costs required to meet demand in the National Electricity Market (NEM) going forward;
- avoid capital costs associated with enabling greater integration of renewables in the NEM; and
- generate sufficient benefits to recover the project capital costs seven years after the option is commissioned.

Benefits from expanding transmission transfer capacity between NSW and Queensland

The driver for the investment options considered as part of this RIT-T is to create a net benefit to consumers and producers of electricity and to support energy market transition through:

- allowing for more efficient sharing of generation across the NEM, thereby avoiding the use of higher cost generators and deferring, or avoiding, the construction of new, more expensive generation and/or storage capacity;
- continuing to provide reliable supply at the lowest cost by deferring the need to build new generation and storage capacity in NSW ahead of the forecast retirement of Liddell Power Station; and
- facilitating the transition to a lower carbon emissions future and the adoption of new technologies through improving access to high quality renewable resources across regions, which further avoids the use of high-cost generators and defers, or avoids, the need to build new generation.

The 2018 ISP concluded that market benefits associated with an expansion of transfer capacity in the near-term can be realised as soon as this can be provided due to it reducing the need for new gas-fired generation in NSW to meet demand once Liddell Power Station retires, as well as benefits from allowing more efficient generation sharing between NSW and Queensland. The 2018 ISP conclusions have been reinforced by the assessment in this PACR and the draft 2020 ISP findings released by AEMO on 12 December 2019.[8]

This PACR finds that the net benefit gained by expanding transfer capacity between NSW and Queensland allows for a lower cost 'filling of the gap' in electricity supply following Liddell Power Station's forecast closure, compared to what might otherwise occur.

The findings of this RIT-T have benefited from extensive stakeholder consultation

TransGrid and Powerlink have undertaken extensive consultation and engaged with stakeholders on various aspects of this RIT-T process. Following publication of the PADR and the accompanying modelling material on 30 September 2019, we held a webinar in October 2019 to help explain the assessment to stakeholders and to seek their views. TransGrid and Powerlink also presented on the RIT-T progress at their relevant Customer Panels and planning forums.

Eight formal submissions were received in mid-November 2019 of which five proposed 'virtual transmission line' solutions.

TransGrid and Powerlink have clarified a number of points raised in submissions and provided submitters the opportunity to better understand the RIT-T assessment process. Where 'virtual transmission line' solutions have been proposed, this has also involved a number of follow-up emails with proponents of these solutions in order for us to better understand these proposals.

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[8] AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, p. 50.

We have taken all feedback raised in submissions into account in undertaking our PACR analysis, as explained throughout this document (together with an appendix providing a comprehensive list of key points raised through stakeholder engagement and responses to each).

This PACR assessment focuses on the four incremental network upgrades

The table below summarises the credible options assessed in this PACR. All credible options are able to be delivered, and inter-network testing completed, by June 2022.

Table E-1 Summary of credible options assessed as part of this PACR

Option description	Indicative total transfer capacity (MW)[9]		Estimated capex ($m)
	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	690	1,120	230
Option 1B – Uprate Liddell to Tamworth lines only	570	1,070	43
Option 1C – Install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks	480	1,120	187
Option 1D – Sapphire substation cut into line 8C and a mid-point switching station between Dumaresq and Bulli Creek	480	1,110	59

Option 1A is the 2018 ISP recommended ‘Group 1’ investment and the draft 2020 ISP recommended ‘QNI minor’ investment. The other network options have been developed based on additional studies and consultation undertaken since the 2018 ISP, including on this RIT-T’s PSCR. These options reflect alternate, lower cost options targeting different transfer limits that would provide different market benefits.

The procurement and contracting process for Option 1A that TransGrid has progressed in parallel to this PACR[10] has resulted in the capital costs of this option being revised since the PADR. The proportionate increases in the cost of each of this option’s key components have been applied to the other options involving incremental upgrades to the existing network to increase transfer capacity for consistency (i.e., Option 1B, Option 1C and Option 1D), as TransGrid considers that the factors that have driven the higher costs would apply equally to these options.

‘Virtual transmission line’ solutions have not been assessed as part of this PACR due to their untested nature at this scale in Australia (and hence unproven technical feasibility at this point in time). We have set out important information for proponents of these solutions below, including how they can be assessed going forward as part of the QNI medium upgrade process, which will allow time for AEMO, TransGrid and Powerlink to test the technical feasibility of these options.

[9] 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. Appendix D of the PADR and section 5.1 to 5.4 of this PACR provides additional detail on the modelled transfer capacities of the options, across a range of operating states. As outlined in the Inputs and Methodology Consultation Paper in December 2018, System Technical Analysis undertaken since the PSCR was released resulted in refining the definition of the QNI transfer capacity.

[10] Consistent with the timelines in the AER guidance note for this RIT-T, see: AER, *Queensland-NSW Interconnector RIT-T guidance notice and engagement process*, available at: https://www.aer.gov.au/communication/queensland-nsw-interconnector-rit-t-guidance-notice-and-engagement-process

The PACR continues to find that 'Option 1A' is the preferred option

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.

Four scenarios have been considered as part of this PACR, which are intended to cover a wide range of possible futures and are generally aligned with the AEMO 2020 ISP 'slow change', 'neutral' and 'fast change' scenarios. The four scenarios are the same as applied in the PADR and differ in relation to key variables expected to affect the market benefits of the options considered, including demand outlook, assumed generator fuel prices, assumed emissions targets, retirement profiles for coal-fired power stations, and generator and storage capital costs.

The results of the PACR assessment find that uprating the Liddell to Tamworth lines, installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks ('Option 1A') is expected to deliver approximately $170 million in net benefits over the assessment period (on a weighted-basis). While Option 1A is effectively ranked equally with Option 1B on a weighted-basis, TransGrid and Powerlink note that:

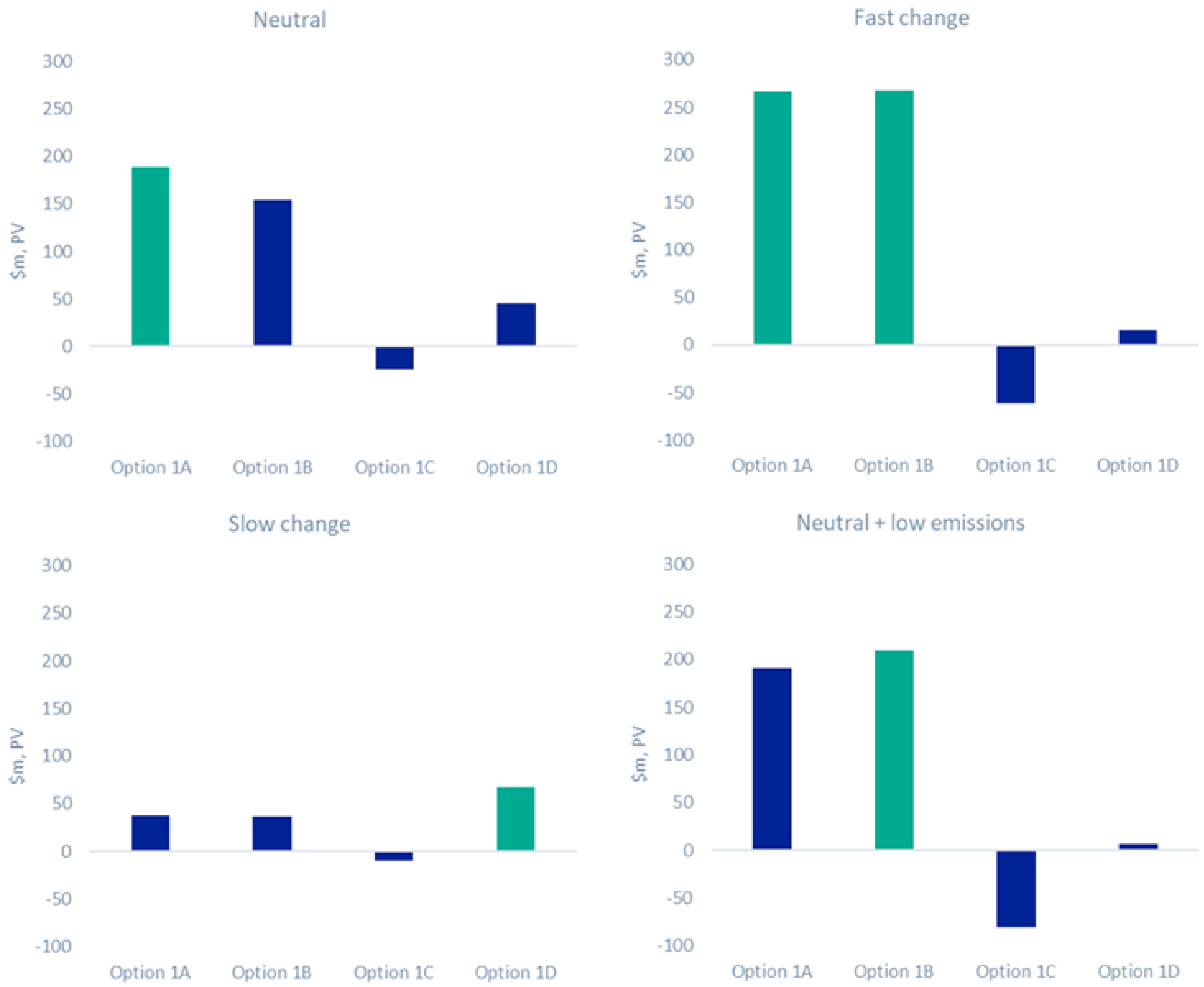
- Option 1A is expected to provide materially higher net benefits than Option 1B under the neutral scenario, which is considered the most likely scenario of the four scenarios investigated;
- we have run a threshold test that shows that the neutral scenario would only need to be given a weighting of 36 per cent (with the other three scenarios weighted equally) for Option 1A to deliver at least five per cent greater net benefits than Option 1B on a weighted basis;
- the only scenario where Option 1B is expected to deliver materially higher net benefits than Option 1A is the 'neutral + low emissions' scenario, which is a bespoke scenario developed to further stress test the RIT-T assessment following feedback from TransGrid's NSW & ACT Transmission Planning forum in November 2018 (i.e., before the ISP scenarios were finalised); and
- Option 1A provides more transmission capacity at times of peak demand in NSW (Option 1B on its own does not increase southerly capacity between Queensland and NSW).

In addition, while Option 1D is found to have the greatest estimated net benefits under the slow-change scenario, it has very low net benefits under the other three scenarios (as well as on a weighted basis) and so is not considered a contender for the preferred option.

Overall, Option 1A is the preferred option identified under this RIT-T. Option 1A is also the option assessed and recommended by AEMO in both the 2018 ISP and the draft 2020 ISP.

The market benefits of all options are primarily derived from the avoided or deferred costs associated with generation and storage in NSW, compared to the base case. This benefit arises since the expanded transfer capacity between NSW and Queensland under each option allows Queensland generation to export to NSW, reducing the need for new investment in generation in NSW.

Figure E.1 – Estimated net benefits for each scenario



Further information and next steps

This PACR represents the final stage in the RIT-T process.

TransGrid is now in the midst of the pre-investment activities necessary to proceed with the preferred option and will be seeking a determination by the AER that the proposed investment satisfies the RIT-T as well as seeking AER approval of a contingent project allowance for this investment.

The box below summarises important information for proponents of 'virtual transmission line' solutions on how they can engage with AEMO, TransGrid and Powerlink as part of the separate assessment process for the 'QNI medium' upgrade.

Further details in relation to this project can be obtained from regulatory.consultation@transgrid.com.au

Opportunities for proponents of 'virtual transmission line' solutions

While consultation with proponents of 'virtual transmission line' options since the PADR has resulted in the stated costs of these technologies falling (meaning they are more likely to be 'economically feasible'), credible options under the RIT-T are also required to be 'technically feasible'.

A proportionate approach to assessing technical feasibility of these solutions was adopted in the PADR, which effectively assumed that these options were technically feasible. This approach was taken in order to compare all options simply on their expected net market benefits (i.e., putting aside technical feasibility) and had no bearing on the conclusion at the PADR stage since these options were not found to be the top-ranked options.[11]

This approach has not been taken as part of the PACR since the assessment is required to identify the preferred credible option. A 'virtual transmission line' comprised of grid-connected battery systems and/or braking resistors of this magnitude would be the first in Australia and there is substantive additional network testing that is required in order to comprehensively determine technical feasibility. TransGrid and Powerlink consider that determining whether these solutions are likely to be technically feasible will require around twelve months of further work and consultation with proponents.

TransGrid and Powerlink envisage that 'virtual transmission lines' may form a potential option considered as part of the medium term QNI upgrade recommended in the draft 2020 ISP, for which a PADR is required by 10 December 2021. This timeframe does allow for a comprehensive assessment of the technical feasibility of these options.

TransGrid and Powerlink therefore encourage proponents of these solutions to respond to the current draft 2020 ISP consultation, both in relation to:

- the capabilities of these technologies generally (to inform the ISPs consideration of these technologies as network solutions); and
- if they propose non-network solutions.

This will enable consideration of those technologies by AEMO as part of the final 2020 ISP. AEMO's deadline for submissions on the draft 2020 ISP is 21 February 2020 and their deadline for non-network submissions in relation to the QNI medium upgrade is 13 March 2020.[12]

TransGrid and Powerlink would welcome technical discussions with proponents before this date to help inform their submissions. This could include types of models and information which would help inform the technical feasibility of a 'virtual transmission line' solution.

Proponents should provide detailed technical information on their proposed option, including PSSE and PSCAD models and complete technical performance information, to enable them to be fully assessed.

[11] Specifically, at the PADR stage, while Option 5B was the top-ranked 'virtual transmission line' option, and had the greatest estimated gross benefit of all options, it was only expected to deliver around 60 per cent of the expected net benefits of Option 1A (on a weighted-basis). This was driven by the relatively high costs associated with Option 5B based on submissions from proponents at the time, which include high upfront costs and as the need to reinvest during the assessment period due to the comparatively shorter life of the energy storage components.

[12] AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, pp. 16 & 82.

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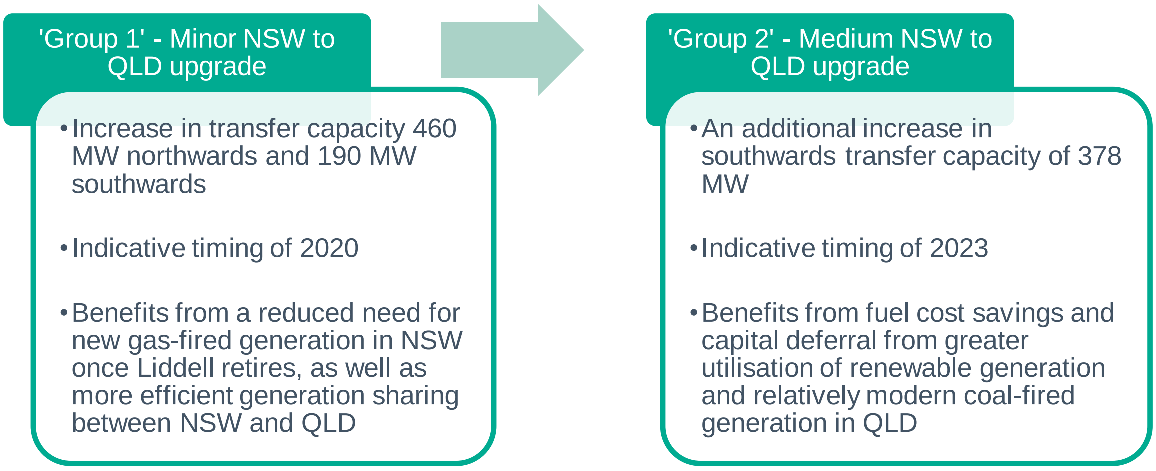
1. Introduction

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, and existing, aging coal-fired power stations are forecast to retire.

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 (NSW) 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 near-term (by around 2020) and over the medium-term (by the mid-2020s), respectively, as shown in Figure 2.

Figure 2 – The 2018 AEMO ISP recommended two expansions to NSW-QLD transfer capacity



The draft 2020 ISP, released on 12 December 2019, built on this assessment and has recommended three upgrades to transmission network capacity between NSW and Queensland be considered. Namely:[13]

- a Queensland to NSW Interconnector minor upgrade (‘QNI minor’) – this upgrade is classified as a ‘Group 1 actionable ISP project’ and relates to Option 1A assessed in this RIT-T and is stated to be completed in 2021-22;
- a ‘QNI medium’ upgrade – this upgrade is to increase Queensland transfer capacity to NSW by 760 MW and is recommended to be delivered by 2028-29 (with an option of accelerating delivery to 2026-27 should the ‘step-change’ scenario emerge); and
- a ‘larger QNI’ upgrade – after the development of a ‘QNI medium’ upgrade, AEMO states that a larger QNI upgrade could be needed in the 2030’s to increase the capacity of the network to host renewable energy and share both storage and firming services between the regions.

In November 2018, TransGrid and Powerlink released a Project Specification Consultation Report (PSCR) and initiated a Regulatory Investment Test for Transmission (RIT-T) to progress the 2018 ISP’s recommendations to increase the transfer capacity between NSW and Queensland.

13 AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, pp. 11-12 & 71.

This Project Assessment Conclusions Report (PACR) has been prepared as the final formal document in the 'expanding NSW-QLD transmission transfer capacity' RIT-T process and follows the Project Assessment Draft Report (PADR) released in September 2019.

As was outlined in the PADR, this RIT-T focusses on options for increasing transfer capacity between NSW and Queensland in the near-term, consistent with the assessment of the 'Group 1' QNI expansion in the 2018 ISP and 'QNI minor' in the draft 2020 ISP, as well as guidance from the Australian Energy Regulator (AER).[14] This near-term focus ensures that the consideration of medium-term options (i.e., 'QNI medium' in the draft 2020 ISP) does not delay the consideration of near-term options required to ensure the greatest net benefits to NEM participants, particularly in light of the forecast closure of Liddell Power Station over 2022 and 2023.

The medium-term options included in the PSCR will be assessed as part of a separate RIT-T in the future. This subsequent RIT-T's PADR is required to be published by 10 December 2021 at the latest, in-accordance with the draft 2020 ISP recommendations.[15]

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

1.1 Role of this report

This PACR summarises the assessment of options for expanding transmission transfer capacity between NSW and Queensland in the near-term. Specifically, it assesses a range of more granular options than were assessed in the 2018 ISP and the draft 2020 ISP that would address the near-term need and presents the cost-benefit analysis of these options.

Specifically, this report:

1. identifies and confirms the market benefits expected from expanding transfer capacity between the two states;
2. summarises points raised in submissions to the PADR and the accompanying consultation material (including the webinar held in October 2019), and highlights how these have been addressed in the RIT-T analysis;
3. describes the options assessed under this RIT-T;
4. presents the results of the NPV analysis for each of the credible options assessed;
5. describes the key drivers of these results, and the assessment that has been undertaken to ensure the robustness of the conclusion; and
6. identifies the ultimately preferred option under the RIT-T, i.e., the option that is expected to maximise net benefits.

Overall, this report provides transparency into the planning considerations for progressing the near-term QNI upgrade component of the 2018 ISP and draft 2020 ISP recommendations.

A key purpose of this RIT-T has been to provide interested stakeholders the opportunity to review the analysis and assumptions, provide input to the process, and have certainty and confidence that the preferred option has been robustly identified as optimal.

TransGrid and Powerlink are also releasing supplementary material on their websites to complement this PACR. Detailed cost benefit results are included as a spreadsheet appendix to this report.

[14] AER, *Queensland-NSW Interconnector RIT-T guidance notice and engagement process*, available at: https://www.aer.gov.au/communication/queensland-nsw-interconnector-rit-t-guidance-notice-and-engagement-process

[15] AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, p. 67. This required timing will be confirmed, or otherwise, in the final 2020 ISP that is expected to be published in mid-2020.

1.2 Further information and next steps

This PACR represents the final stage in the RIT-T process.

TransGrid is now in the midst of the pre-investment activities necessary to proceed with the preferred option and will be seeking a determination by the AER that the proposed investment satisfies the RIT-T as well as seeking AER approval of a contingent project allowance for this investment.

Further details in relation to this project can be obtained from regulatory.consultation@transgrid.com.au

2. Benefits from a near-term upgrade are expected to be realised immediately

Summary of key points:

- The driver for the investment options considered in this PACR is to deliver a net economic benefit to consumers and producers of electricity and support energy market transition through:[16]
  - allowing for more efficient sharing of generation across the NEM, thereby avoiding the use of higher cost generators and deferring, or avoiding, the construction of new, more expensive generation and/or storage capacity;
  - continuing to provide reliable supply at the lowest cost by deferring the need to build new generation and storage capacity in New South Wales (NSW) ahead of the forecast retirement of Liddell Power Station; and
  - facilitating the transition to a lower carbon emissions future and the adoption of new technologies through improving access to high quality renewable resources across regions, which further avoids the use of high-cost generators and defers, or avoids, the need to build new generation.
- This is therefore a 'market benefit' RIT-T (as opposed to a 'reliability corrective action' RIT-T).
- The 2018 ISP concluded that market benefits associated with the Group 1 upgrade can be realised as soon as these investments can be built due to a reduced need for new gas-fired generation in NSW to meet demand once Liddell retires, as well as benefits from allowing more efficient generation sharing between NSW and Queensland.[17]
  - The draft 2020 ISP and results of this RIT-T have confirmed this finding.
- The net benefits from the medium-term upgrade options (e.g., 'QNI medium' in the draft 2020 ISP) are expected to add to these net benefits and will be assessed as part of a subsequent RIT-T process.
  - The draft 2020 ISP requires the PADR for this subsequent RIT-T to be issued by 10 December 2021.

2.1 Benefits from avoided new generation and storage costs in NSW following the forecast closure of Liddell Power Station

The 2018 ISP concluded that an upgrade to the transmission transfer capacity between NSW and Queensland in the near-term would provide benefits in terms of the reduced need for new gas-fired generation in NSW to meet demand once Liddell retires.[18]

Each of the credible options assessed as part of this PACR expand the transfer capacity between NSW and Queensland and allow the supply-demand balance in NSW to continue to be met but at a lower cost than if

[16] While the summary of these three broad sources of expected benefit have changed minorly since the PSCR to reflect the market modelling now undertaken (and presented in the PADR), the 'identified need' for this RIT-T remains unchanged, i.e., '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'.

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

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

new generation and/or storage capacity was to be constructed in NSW following the forecast retirement of Liddell Power Station (and other thermal plants further in the future).

The market modelling undertaken as part of this RIT-T finds that the preferred option enables investment in new capacity to be avoided or deferred in NSW. The mix of the technologies avoided depends on the specific scenario modelled including open-cycle gas turbine (OCGT) plant or new renewable technologies (primarily solar, wind, pumped hydro and large-scale storage).

2.2 Benefits from more efficient sharing of generation

The 2018 ISP also concluded that an upgrade to the transmission transfer capacity between NSW and Queensland in the near-term would provide benefits in terms allowing for more efficient generation sharing between NSW and Queensland going forward.[19] This finding has been confirmed by the draft 2020 ISP.

More efficient generation sharing from increasing transfer capacity between Queensland and NSW arises as a result of geographical weather diversity. This results in peak demand in each region (and other interconnected regions) occurring at different times as well as different renewable generation levels at different sites (particularly for wind generation). The non-coincidence of demand enables generation capacity to be shared across the interconnected system.

Given the non-coincidence of peak demand in Queensland and NSW, an expansion of 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 lower cost generating capacity in other regions. Sharing of generation is therefore also expected to facilitate substitution of higher fuel cost plant with lower fuel cost plant, which would lower the overall cost of dispatch of generation. This is another key category of market benefit under the RIT-T.[20]

The market modelling undertaken in this RIT-T finds that avoided generator fuel cost is a benefit for the options considered but is small relative to the benefits from avoided new generation and storage costs in NSW following Liddell's forecast closure.

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.

2.3 Benefits attributable to the transition to lower carbon emissions

Australia's COP21[21] 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.[22]

Northern NSW and southern Queensland have some of the highest quality renewable energy resources in Australia, including solar, wind and pumped-hydro potential.

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19 AEMO, *Integrated System Plan,* July 2018, p. 83.

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

21 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.

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

As part of the 2018 ISP, an extensive investigation of the renewable energy resources in, and near, existing NEM infrastructure was undertaken by AEMO. In particular, the 2018 ISP outlines potential renewable energy zones across the NEM and includes four directly on the existing QNI route (i.e., zones 6, 7, 8 and 30).[23]

The 2018 ISP investigations confirmed that there are good solar resources to the west of the QNI corridor and that there are also good wind and pumped hydro resources to the east of the QNI corridor. The 2020 ISP is continuing to consider how to best develop REZs in the future so that their development is optimised together with necessary power system developments, as well as identifying indicative timing and staging that will best coordinate REZ developments with identified transmission developments to reduce overall costs.

Expanding the transfer capacity of QNI will allow Queensland renewable developments to be more effectively exported in the long-term, and this can displace higher cost generation and avoid investment elsewhere in the NEM. Importantly for this RIT-T, the Queensland government has committed to a range of actions regarding renewable generation, including the Queensland Renewable Energy Target ('QRET') – a renewable energy target of 50 per cent by 2030.[24]

Within the context of the RIT-T assessment, greater interconnection between NSW and Queensland that facilitates the transition to lower carbon emissions in the long-term can be expected to add to the classes of market benefit outlined in 3.1 and 3.2 above – specifically through:

- further reductions in total dispatch costs, by enabling low cost renewable generation to displace higher cost conventional generation; and
- 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 less favourable locations limited by congestion on the existing transmission system.

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.

2.4 Medium-term QNI upgrade options are expected to add to these benefits

The 2018 ISP found that the recommended medium-term upgrade is projected to provide market benefits from additional 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.[25]

Whether this RIT-T would cover both sets of options was raised during both the February 2019 webinar[26] and the Powerlink Customer Panel briefing.[27] While the response at the time was that the expected outcome of this RIT-T would be the identification of a 'preferred option' comprising of the optimal series of investments over both the near-term and medium-term, the revised focus of the RIT-T has necessitated the consideration of these medium-term options as part of a subsequent RIT-T process.[28]

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23 Please refer to the ISP and accompanying material for a definition of these zones.

24 https://www.dnrme.qld.gov.au/__data/assets/pdf_file/0008/1253825/powering-queensland-plan.pdf

25 AEMO, *Integrated System Plan*, July 2018, p. 94.

26 Stakeholder webinar summary, p. 1.

27 Powerlink Customer Panel briefing summary, p. 1.

28 Consistent with AER, *Queensland-NSW Interconnector RIT-T guidance notice and engagement process*, available at: https://www.aer.gov.au/communication/queensland-nsw-interconnector-rit-t-guidance-notice-and-engagement-process

AEMO released its draft 2020 ISP on 12 December 2019, which recommended two further upgrades to transmission network capacity between NSW and Queensland be considered (i.e., in addition to Option 1A), namely:[29]

- a 'QNI medium' upgrade – recommended to be delivered by 2028-29 with an option of accelerating delivery to 2026-27 should the 'step-change' scenario emerge; and
- a 'larger QNI' upgrade – after the development of a 'QNI medium' upgrade, AEMO states that a larger QNI upgrade could be needed in the 2030's to increase the capacity of the network to host renewable energy and share both storage and firming services between the regions.

The medium-term upgrade options will be assessed as part of a separate RIT-T in the future. This RIT-T's PADR is required to be published by 10 December 2021 at the latest, in accordance with the draft 2020 ISP recommendations.[30]

[29] AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, pp. 11-12 & 71.

[30] AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, p. 67. The latest time for this PADR will be confirmed, or otherwise, in the final 2020 ISP to be published mid-2020.

3. Consultation on the PADR

Summary of key points:

- We have undertaken extensive stakeholder consultation over the course of this RIT-T to investigate the potential credible options for expanding transfer capacity between New South Wales (NSW) and Queensland in the near-term and ensure the robustness of the RIT-T findings.
- This consultation has included two webinars (one for the PSCR and one for the PADR), publication of a separate detailed market modelling and assumptions report, briefing our respective Customer Panels, bilateral discussions with interested stakeholders, and the release of detailed analysis in response to stakeholder requests.
- We briefed the Powerlink and TransGrid Customer Panels on this refined focus and presented at our Transmission Network and Annual Planning forums in September 2019.
- We thank all parties for their valuable input to the consultation process.

Following publication of the PADR and the accompanying modelling material we held a webinar in October 2019 to explain the assessment to stakeholders and to seek their views on the assessment.

Eight formal submissions were subsequently received in response to the PADR. TransGrid and Powerlink have published all submissions on our websites where confidentially has not been requested.[31] While submissions covered a range of topics, there were two broad topics that were most commented on, namely:

- the modelling undertaken; and
- 'virtual transmission line' options.

TransGrid and Powerlink have clarified a number of points raised in submissions and provided submitters the opportunity to better understand the RIT-T assessment process. Where 'virtual transmission line' solutions have been proposed, this has also involved a number of follow-up emails with proponents to further the definition and understanding of these technologies.

The key matters raised in submissions relevant to the RIT-T are summarised below, together with the TransGrid and Powerlink responses. Appendix D provides a summary of all points raised as part of consultation on the PADR, and responses to those points.

3.1 Modelling undertaken

Stakeholders raised a range of points in relation to the modelling undertaken. These are summarised below.

3.1.1 Approach to assumptions for forced outage rates

Origin Energy[32] and Engie[33] noted that forced outage rates adopted in our modelling are higher than those assumed by AEMO in the ISP and ESOO. It was suggested that the higher rates could lead to overestimating benefits from higher levels of unserved energy that could be addressed by credible options.

In the market modelling conducted for this RIT-T, EY has considered generator forced outage rates together with other outage events that have occurred over the last five years to arrive at 'availability rates' (i.e., not just

31 https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity & https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity

32 Origin submission, p. 1.

33 Engie submission, pp. 2-3.

forced outage rates). While recognising this differs from assumptions used by AEMO, this approach is considered more reflective of actual generator performance and availability rates.

While we consider this approach produces more realistic results, an additional sensitivity has been undertaken in this PACR using forced outage rates consistent with AEMO assumptions. Results from this sensitivity indicate that by adopting AEMO based forced outage rate assumptions is not material for this RIT-T assessment (as presented in section 7.6.1).

3.1.2 Demand forecasts

Demand forecasts applied in the market modelling have been sourced from the 2018 ESOO, which has subsequently been updated in the 2019 ESOO. Origin Energy raised the possibility of using the updated 2019 ESOO for demand forecasts, given that the 2018 ESOO has higher demand forecasts than the updated 2019 ESOO.[34]

We have not updated the demand forecasts used in this PACR and consider that any difference in underlying demand forecasts is unlikely to have a material effect on the overall option rankings or the preferred option. In particular, we consider that any differences in underlying demand forecasts are unlikely to affect the amount of gas-fired generation displaced in NSW with the options in-place. Even with a lower demand forecast, significant new OCGT capacity is likely needed in the base case and the amount deferred due to Options 1A-D would be similar to the 2018 ESOO forecast.

Origin Energy also suggested that modelling could include demand shocks (e.g., decommissioning of a smelter) as a sensitivity.[35]

We have not investigated the effects of a demand shock as part of this PACR and consider that a demand shock of the severity (large), timing (early in the assessment period) and location (NSW) to affect the conclusion of this RIT-T is highly unlikely. For example, while the Tomago aluminium smelter shutting down is considered one example of such a shock, we note that the Tomago Aluminium Company has signed an eleven year base-load power supply contract with Macquarie Generation that expires in 2028 (which is after the seven year payback period estimated for Option 1A in this PACR).[36] We note also that the slow-change scenario has a noticeable decrease in NSW demand from around 2028 (that is considered akin to a negative demand shock) and Option 1A is still found to have significant net benefits under this scenario.

3.1.3 Effect of transfer capacity on additional system security requirements

Origin Energy expressed a view that it would be useful to describe how the modelling has captured recent transfer capacity reductions due to voltage constraints, and the effect future generation may have on transfer capacity due to additional system security requirements.[37]

TransGrid and Powerlink note that the QNI transfer level is determined by thermal, voltage and transient limits with different modes of failure and critical contingencies for different operating conditions. The calculated limits are implemented in the market modelling package to adequately represent the QNI transfer capacity available for the prevailing system conditions.

Appendix D of the PADR and sections 5.1 to 5.4 of this PACR summarise the results of detailed power system studies performed on each of the credible options across a range of representative operating conditions, including the voltage stability limitation leading to the recent reduction. The range of limits modelled is considered to be sufficient to thoroughly test the differences that can be realistically expected across the credible options.

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[34] Origin submission, p. 2.

[35] Origin submission, p. 2.

[36] https://www.csr.com.au/investor-relations-and-news/csr-news-releases/2010/tomago-aluminium-secures-long-term-power-supply-contract

[37] Origin submission, p. 2.

The market modelling undertaken models network congestion under each option and the base case, for each of the scenarios and sensitivities considered. A comparison is then made between the option case and the base case.

3.1.4 Other points raised in relation to the modelling undertaken

Origin Energy suggested TransGrid and Powerlink consider weighting the neutral scenario higher, assuming that this scenario is considered to be the most likely scenario. Origin Energy also stated it was not clear as to why all scenarios had equal weighting.[38]

We have weighted each of the scenarios equally (i.e., 25 per cent each) in lieu of evidence or rationale for an alternate weighting, which is consistent with the RIT-T.[39] In effect this gives many of the assumptions in the AEMO 'neutral' scenario a higher weighting than in the 'slow change' or 'fast change' scenarios (since there are now two variants of the neutral scenario). We consider this appropriate because the low and high scenarios represent a less likely combination of assumptions occurring simultaneously across a range of variables.

While the results find that Option 1A and Option 1B provide similar net benefits on a weighted-basis, we note that Option 1A is expected to provide materially higher net benefits than Option 1B under the neutral scenario (which is considered the most likely scenario of the four scenarios investigated). The only scenario where Option 1B is expected to deliver materially higher net benefits than Option 1A is the 'neutral + low emissions' scenario, which is a bespoke scenario developed to further stress test the RIT-T assessment following feedback from TransGrid's NSW & ACT Transmission Planning forum in November 2018 (i.e., before the ISP scenarios were finalised).This is discussed further in section 7.5.

Origin Energy also enquired about the assumptions underpinning fuel price forecasts adopted in the modelling.[40] Fuel price forecasts are based on AEMO's 2020 ISP assumptions and forecasts, which have been consulted on. AEMO also publishes consultant reports that describe fuel price assumptions and forecasts, including those from Core Energy and Wood Mackenzie for gas and coal prices respectively.

3.2 'Virtual transmission line' options

Five of the eight submissions to the PADR were from potential proponents of 'virtual transmission lines'. While much of the submitted material cannot be reproduced in the PACR for confidentiality reasons, this section summarises some of the high-level points raised.

As outlined in section 5.5, 'virtual transmission line' solutions have not been assessed as credible options as part of this PACR due to their unproven technical feasibility at this point in time. Proponents of these technologies are encouraged to respond to AEMO's current draft 2020 ISP consultation, both in relation to the capabilities of these technologies generally (to inform the ISPs consideration of these technologies as network solutions) and if they propose non-network solutions, as well as to engage with the RIT-T process for 'QNI medium' going forward.

TransGrid and Powerlink envisage that these technologies may form a potential credible option considered as part of the medium-term QNI upgrade recommended in the 2020 ISP, for which a PADR is required by 10 December 2021. This timeframe does allow for a comprehensive assessment of the technical feasibility of these solutions.

Stakeholder submissions to the PADR raised new applications of these technologies (i.e., in addition to those proposed in the PADR). The new applications relate to refining the 'virtual transmission line' options to include both the consideration of braking resistors in Queensland (as opposed to a battery in NSW paired with a second

[38] Origin submission, p. 2.

[39] RIT-T, clause (4)(a)(ii).

[40] Origin submission, p. 2.

battery in Queensland) as well as these options combined with the top-ranked incremental network option identified in the PADR (‘Option 1A’).

Where a braking resistor is employed, we note that the applications above will only enable the southerly transfer limits of QNI to be increased (and there would be no change to the northerly transfer limits).

Tesla and other stakeholders raised the capabilities of energy storage solutions in providing other services including premium Frequency Control Ancillary Services, Voltage Control Ancillary Services, virtual inertia and Marginal Loss Factor improvements.[41]

While this PACR does not assess any ‘virtual transmission line’ options, their ability to provide these services may be relevant for their consideration in the final 2020 ISP assessment and/or the forthcoming RIT-T process for ‘QNI medium’.

[41] Tesla submission, p. 4.

4. Key developments since the PADR

Summary of key points:

- The Commonwealth and New South Wales (NSW) Governments have underwritten the early works required for the preferred QNI upgrade identified at the PADR stage (ie, 'Option 1A').
  - TransGrid is also working with the NSW Government, as part of its NSW Transmission Infrastructure Strategy, on a range of initiatives to support early development of Option 1A by bringing forward early planning and feasibility work.
- Option 1A's cost estimates have been revised on account of the procurement and contracting process undertaken in parallel to this PACR.
  - The other incremental network upgrade option costs used in this PACR have consequently also been updated based on the learnings/information from the procurement process.
- The recently released AEMO draft 2020 ISP has reconfirmed the importance of Option 1A's network upgrade and labelled it a 'no regret' action.

4.1 Commonwealth and NSW Governments have underwritten Option 1A

On 28 October 2019, the Commonwealth and NSW Governments announced they would each contribute $51 million (i.e., $102 million in total) to underwriting the early works required for the preferred QNI upgrade identified at the PADR stage (i.e., 'Option 1A'). This was to allow TransGrid to fast-track critical early works for the QNI upgrade ahead of the final regulatory determination of the AER (specifically, the AER determination on TransGrid's contingent project application).[42] TransGrid considers this underwriting a key facilitator of delivering the upgrade in the timeframes specified.

This builds on the NSW Government releasing its NSW Transmission Infrastructure Strategy in November 2018, which stated it will support early development of the preferred near-term option (i.e., consistent with the 2018 ISP 'Group 1' timings) by bringing forward early planning and feasibility work. TransGrid has been working with the NSW Government on this initiative.

In addition, in November 2019, the NSW Government also released the NSW Electricity Strategy, which includes a Central-West Renewable Energy Zone (REZ) pilot. The strategy states that it is expected that this pilot will unlock up to 3,000 MW of new generation by the mid-2020's.[43] At the 22nd COAG Energy Council meeting on 22 November 2019, the NSW Government stated its intention to fast-track this REZ.[44]

TransGrid and Powerlink support the proposed development of the Central-West REZ and do not consider that it will have a material impact on the findings of this RIT-T. In particular, the market modelling undertaken in this RIT-T allows for major REZ investment in central NSW and finds that, under both the base case and the option cases, significant amounts of solar and wind generation locate there. While the NSW Electricity Strategy is expected to bring forward these developments, it is not expected to affect the conclusion that Option 1A is the preferred option under this RIT-T.

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42 https://minister.environment.gov.au/taylor/news/2019/ensuring-future-reliable-electricity-supply-nsw

43 https://energy.nsw.gov.au/renewables/renewable-energy-zones

44 http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/EC%20-%20Final%20Communique.pdf

4.2 Option 1A's cost estimates have been revised as a result of the parallel procurement and contracting process

In order to be in a position to submit the contingent project application for the preferred option, consistent with the guidance from AER,[45] TransGrid has progressed the detailed project works specification and procurement steps to deliver Option 1A's scope and outcomes. This process has developed and substantiated detailed cost estimates for each component of Option 1A, which have been used in the economic modelling presented in this PACR.

The other incremental network upgrade option costs used in this PACR have also been updated based on the learnings/information from this procurement process. TransGrid considers that the costs of these other options would also be affected by the same drivers that have led to the higher cost estimate for Option 1A.

4.3 AEMO's draft 2020 ISP results have reconfirmed the importance of Option 1A's network upgrade and labelled it a 'no regret' action

AEMO released its draft 2020 ISP on 12 December 2019 that reconfirmed the network augmentations proposed under Option 1A are required by 2021-22. The draft 2020 ISP has recommended three upgrades to transmission network capacity between NSW and Queensland be considered, namely:[46]

- 'QNI minor' – this upgrade is classified as a 'Group 1 actionable ISP project' and relates to Option 1A assessed in this RIT-T and is stated to be completed in 2021-22;
- 'QNI medium' – this upgrade is to increase Queensland transfer capacity to NSW by 760 MW and is recommended to be delivered by 2028-29 (with an option of accelerating delivery to 2026-27 should the 'step-change' scenario emerge); and
- a 'larger QNI' upgrade – after the development of a 'QNI medium' upgrade, AEMO states that a larger QNI upgrade could be needed in the 2030's to increase the capacity of the network to host renewable energy and share both storage and firming services between the regions.

AEMO has characterised the 'QNI minor' upgrade as a 'no regret' action and included it as one of seven projects in its optimal development path.[47]

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45 AER, *Queensland-NSW Interconnector RIT-T guidance notice and engagement process*, available at: https://www.aer.gov.au/communication/queensland-nsw-interconnector-rit-t-guidance-notice-and-engagement-process

46 AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, pp. 11-12 & 71.

47 AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, pp. 50 & 54.

5. Four options for increasing NSW-QLD transfer capacity in the near-term

Summary of key points:

- This PACR assesses four credible options for increasing transfer capacity between New South Wales (NSW) and Queensland in the near-term.
  - These options reflect incremental upgrades to the existing network to increase transfer capacity.
- 'Virtual transmission line' solutions have not been assessed as part of this PACR due to their untested nature at this scale in Australia (and hence unproven technical feasibility at this point in time).
  - TransGrid and Powerlink envisage that these technologies may form a potential credible option considered as part of the medium-term QNI upgrade recommended in the 2020 ISP, for which a PADR is required by 10 December 2021 (this timeframe does allow for a comprehensive assessment of the technical feasibility of these solutions).
  - Proponents of these technologies are encouraged to respond to the current draft 2020 ISP consultation, both on the capabilities of their technologies generally (to inform the ISPs consideration of these technologies as network solutions) and if they propose non-network solutions.
  - The 2020 ISP consultation process will enable consideration of these technologies by AEMO as part of the final 2020 ISP.
- The medium-term options identified in the PSCR for further increasing transfer capacity (along with 'virtual transmission line' solutions) will be assessed as part of a separate RIT-T in the future.
  - The timing of the PADR for this RIT-T is required to be published by 10 December 2021 at the latest, in accordance with the draft 2020 ISP recommendations.[48]
- Proponents should provide detailed technical information on their proposed option, including PSSE and PSCAD models and complete technical performance information, to enable them to be fully assessed.

This PACR focusses on credible options for increasing transfer capacity between NSW and Queensland in the near-term (i.e., prior to Liddell Power Station's forecast closure). This is consistent with the 2018 ISP focus on the 'Group 1' QNI upgrade and the 'QNI minor' recommended in the draft 2020 ISP.

The table below summarises the credible options assessed in this PACR.[49] All credible options are able to be delivered, and inter-network testing, completed by June 2022.

48 AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, p. 67.

49 The same option naming/numbering convention has been applied as in the PSCR and PADR for consistency, i.e., 'Option 1' for the incremental upgrades to the existing network to increase transfer capacity.

Table 5-1 Summary of credible options assessed as part of this PACR

Option description	Indicative total transfer capacity (MW)[50]		Estimated capex ($m)
	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	690	1,120	230
Option 1B – Uprate Liddell to Tamworth lines only	570	1,070	43
Option 1C – Install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks	480	1,120	187
Option 1D – Sapphire substation cut into line 8C and a mid-point switching station between Dumaresq and Bulli Creek	480	1,110	59

Option 1A is the 2018 ISP recommended 'Group 1' investment and the draft 2020 ISP recommended 'QNI minor' investment. The other network options have been developed based on additional studies and consultation undertaken since the 2018 ISP, including on this RIT-T's PSCR. These options reflect alternate, lower cost options targeting different transfer limits that would provide different market benefits.

The procurement and contracting process for Option 1A that TransGrid has progressed in parallel to this PACR[51] has resulted in the capital costs of this option being revised since the PADR. The proportionate increases in the cost of each of this option's key components have also been applied to the other options involving incremental upgrades to the existing network to increase transfer capacity for consistency (i.e., Option 1B, Option 1C and Option 1D), as TransGrid considers that the factors that have driven the higher costs would apply equally to these options.

All options are assumed to have annual operating costs equal to approximately one per cent of their capital costs.

Sections 5.1 to 5.4 provide a summary of the four credible options assessed in this PACR. We have included a network diagram for each network credible option, which shows the existing network configuration (in black) with works and new elements for each option (in red). In addition, we have reproduced the expected limit increases for each option, across a range of representative operating conditions, from Appendix D of the PADR.[52]

Section 5.5. provides information on the technical feasibility of 'virtual transmission line' options.

[50] 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. Appendix D of the PADR provides additional detail on the modelled transfer capacities of the options, across a range of operating states. As outlined in the Inputs and Methodology Consultation Paper in December 2018, System Technical Analysis undertaken since the PSCR was released resulted in refining the definition of the QNI transfer capacity.

[51] Consistent with the timelines in the AER guidance note for this RIT-T, see: AER, *Queensland-NSW Interconnector RIT-T guidance notice and engagement process*, available at: https://www.aer.gov.au/communication/queensland-nsw-interconnector-rit-t-guidance-notice-and-engagement-process

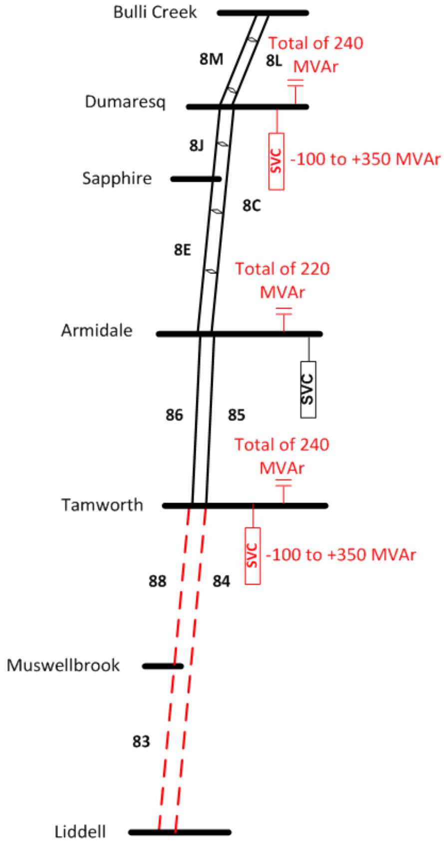
[52] Appendix D of the PADR provides greater detail on the modelled changes to transfer capacities.

5.1 Option 1A – Uprate Liddell to Tamworth lines and install dynamic reactive support and shunt capacitor banks

Option 1A involves incremental investments to the existing network to increase transfer capacity in the near-term. This option is the same as that recommended in the 2018 ISP for Group 1 and remains fundamentally the same as specified in the PSCR and the PADR.

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 by uprating Lines 83, 84 and 88, which are the Liddell to Tamworth via Muswellbrook 330 kV circuits shown earlier in Figure 20. 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.

A SVC is considered as the source of the dynamic reactive support at both Tamworth and Dumaresq.

The estimated capital cost of Option 1A is $230 million (reflecting further option scoping and refinement since the PADR). This option also has additional operating costs associated with refurbishing elements of the SVCs in the future (these costs sum to approximately $8.5 million in total over the assessment period).

Table 5-2 lists notional planning level summer limits, mode of failure and limit improvements provided by Option 1A under six representative operating conditions for high Sapphire Wind Farm (WF) generating conditions (specifically 189MW day time and 270MW night time assumed generation) and low Sapphire WF generating conditions (near 0MW generation). These operating conditions represent boundary and typical conditions made up of the combinations of summer day and night time operation under high, medium and low load conditions. The calculated limits are formularised and implemented in the market modelling package to produce an accurate estimate of the QNI transfer capacity available for the prevailing system conditions.

Table 5-2 Notional QNI limits and limit improvements following Option 1A – Summer

Operating Condition		Notional Limit (MW)		Change from "Do Nothing" (MW)	
		NSW to QLD	QLD to NSW	NSW to QLD	QLD to NSW
High Sapphire	Day High	525 (Thermal)	1,190 (Thermal)	160	120
	Day Medium	690 (Thermal)	1,120 (Thermal)	210	50
	Day Low	940 (Stability)	950 (Thermal)	270	0
	Night High	525 (Thermal)	1,175 (Thermal)	195	175

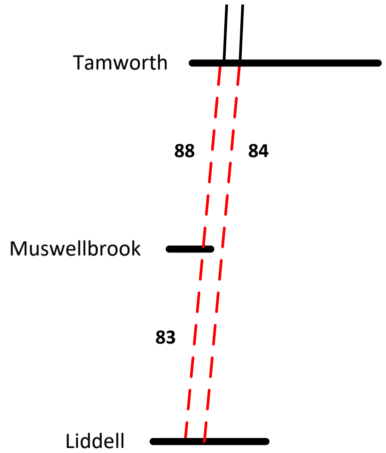
	Night Medium	700 (Thermal)	1,170 (Thermal)	225	180
	Night Low	925 (Stability)	1,045 (Thermal)	290	60
Low Sapphire	Day High	345 (Thermal)	1,360 (Thermal)	155	145
	Day Medium	515 (Thermal)	1,300 (Thermal)	215	95
	Day Low	790 (Thermal)	1,135 (Thermal)	265	5
	Night High	270 (Thermal)	1,370 (Thermal)	200	145
	Night Medium	445 (Thermal)	1,365 (Thermal)	225	150
	Night Low	685 (Stability)	1,295 (Thermal)	240	85

Table 5-3 lists corresponding notional planning level winter limits for Option 1A.

Table 5-3 Notional QNI limits and limit improvements following Option 1A – Winter

Operating Condition		Notional Limit (MW)		Change from "Do Nothing" (MW)	
		NSW to QLD	QLD to NSW	NSW to QLD	QLD to NSW
High Sapphire	Day High	605 (Thermal)	1,280 (Thermal)	180	210
	Day Medium	770 (Thermal)	1,205 (Thermal)	200	135
	Day Low	940 (Stability)	1,030 (Thermal)	270	0
	Night High	560 (Thermal)	1,215 (Thermal)	195	215
	Night Medium	740 (Thermal)	1,220 (Thermal)	195	230
	Night Low	925 (Stability)	1,095 (Thermal)	290	110
Low Sapphire	Day High	430 (Thermal)	1,440 (Thermal)	185	225
	Day Medium	595 (Thermal)	1,390 (Thermal)	220	185
	Day Low	805 (Stability)	1,215 (Thermal)	280	15
	Night High	315 (Thermal)	1,465 (Thermal)	205	240
	Night Medium	490 (Thermal)	1,455 (Thermal)	205	240
	Night Low	685 (Stability)	1,355 (Thermal)	240	145

5.2 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 (Lines 83, 84 and 88), as described in the section above. It remains fundamentally the same as defined in the PSCR and the PADR.

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

The estimated capital cost of Option 1B is $43 million (reflecting further option scoping and refinement since the PADR).

Table 5-4 lists notional planning level summer limits, mode of failure and limit improvements provided by Option 1B under the same six representative operating conditions as provided for Option 1A above.

Table 5-4 Notional QNI limits and limit improvements following Option 1B – Summer

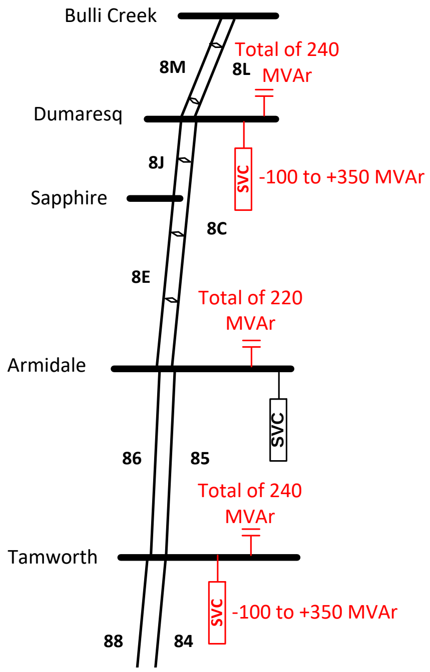
Operating Condition		Notional Limit (MW)		Change from "Do Nothing" (MW)	
		NSW to QLD	QLD to NSW	NSW to QLD	QLD to NSW
High Sapphire	Day High	525 (Thermal)	1,070 (Stability)	160	0
	Day Medium	570 (Stability)	1,070 (Stability)	90	0
	Day Low	670 (Stability)	950 (Thermal)	0	0
	Night High	525 (Thermal)	1,000 (Stability)	195	0
	Night Medium	560 (Stability)	990 (Stability)	85	0
	Night Low	635 (Stability)	985 (Stability)	0	0
Low Sapphire	Day High	345 (Thermal)	1,215 (Stability)	155	0
	Day Medium	375 (Stability)	1,205 (Stability)	75	0
	Day Low	525 (Stability)	1,130 (Thermal)	0	0
	Night High	270 (Thermal)	1,225 (Stability)	200	0
	Night Medium	365 (Stability)	1,215 (Stability)	145	0
	Night Low	445 (Stability)	1,210 (Stability)	0	0

Table 5-5 lists corresponding notional planning level winter limits for Option 1B.

Table 5-5 Notional QNI limits and limit improvements following Option 1B – Winter

Operating Condition		Notional Limit (MW)		Change from "Do Nothing" (MW)	
		NSW to QLD	QLD to NSW	NSW to QLD	QLD to NSW
High Sapphire	Day High	545 (Stability)	1,070 (Stability)	120	0
High Sapphire	Day Medium	570 (Stability)	1,070 (Stability)	0	0
High Sapphire	Day Low	670 (Stability)	1,030 (Thermal)	0	0
High Sapphire	Night High	560 (Thermal)	1,000 (Stability)	195	0
High Sapphire	Night Medium	560 (Stability)	990 (Stability)	15	0
High Sapphire	Night Low	635 (Stability)	985 (Stability)	0	0
Low Sapphire	Day High	410 (Stability)	1,215 (Stability)	165	0
Low Sapphire	Day Medium	375 (Stability)	1,205 (Stability)	0	0
Low Sapphire	Day Low	525 (Stability)	1,200 (Thermal)	0	0
Low Sapphire	Night High	305 (Stability)	1,225 (Stability)	195	0
Low Sapphire	Night Medium	365 (Stability)	1,215 (Stability)	80	0
Low Sapphire	Night Low	445 (Stability)	1,210 (Stability)	0	0

5.3 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. It remains fundamentally the same as defined in the PSCR and the PADR.

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

The estimated capital cost of Option 1C is $187 million (reflecting further option scoping and refinement since the PADR). As with Option 1A, this option also has additional operating costs associated with refurbishing elements of the SVCs in the future (these costs sum to approximately $8.5 million in total over the assessment period).

Table 5-6 lists notional planning level summer limits, mode of failure and limit improvements provided by Option 1C under the same six representative operating conditions as provided for Option 1A above.

Table 5-6 Notional QNI limits and limit improvements following Option 1C – Summer

Operating Condition		Notional Limit (MW)		Change from "Do Nothing" (MW)	
		NSW to QLD	QLD to NSW	NSW to QLD	QLD to NSW
High Sapphire	Day High	365 (Thermal)	1,190 (Thermal)	0	120
	Day Medium	480 (Thermal)	1,120 (Thermal)	0	50
	Day Low	760 (Thermal)	950 (Thermal)	90	0
	Night High	330 (Thermal)	1,175 (Thermal)	0	175
	Night Medium	475 (Thermal)	1,170 (Thermal)	0	180
	Night Low	735 (Thermal)	1,045 (Thermal)	100	60
Low Sapphire	Day High	190 (Thermal)	1,360 (Thermal)	0	145
	Day Medium	300 (Thermal)	1,300 (Thermal)	0	95
	Day Low	580 (Thermal)	1,135 (Thermal)	55	5
	Night High	70 (Thermal)	1,370 (Thermal)	0	145
	Night Medium	220 (Thermal)	1,365 (Thermal)	0	150
	Night Low	480 (Thermal)	1,295 (Thermal)	35	85

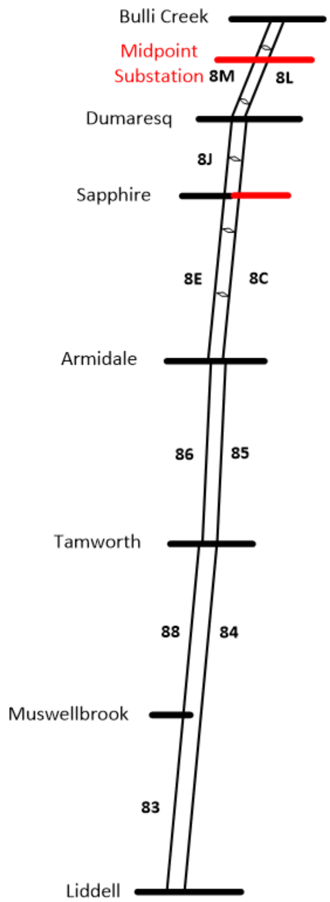
Table 5-7 lists corresponding notional planning level winter limits for Option 1C.

Table 5-7 Notional QNI limits and limit improvements following Option 1C – Winter

Operating Condition		Notional Limit (MW)		Change from "Do Nothing" (MW)	
		NSW to QLD	QLD to NSW	NSW to QLD	QLD to NSW
High Sapphire	Day High	425 (Thermal)	1,280 (Thermal)	0	210
	Day Medium	590 (Thermal)	1,205 (Thermal)	20	135
	Day Low	870 (Thermal)	1,030 (Thermal)	200	0
	Night High	365 (Thermal)	1,215 (Thermal)	0	215
	Night Medium	545 (Thermal)	1,220 (Thermal)	0	230
	Night Low	800 (Thermal)	1,095 (Thermal)	165	110
Low Sapphir	Day High	245 (Thermal)	1,440 (Thermal)	0	225
	Day Medium	410 (Thermal)	1,390 (Thermal)	35	185

	Day Low	690 (Thermal)	1,215 (Thermal)	165	15
	Night High	110 (Thermal)	1,465 (Thermal)	0	240
	Night Medium	285 (Thermal)	1,455 (Thermal)	0	240
	Night Low	545 (Thermal)	1,355 (Thermal)	100	145

5.4 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. It remains fundamentally the same as defined in the PSCR and the PADR.

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 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.

The estimated capital cost of Option 1D is $59 million (reflecting further option scoping and refinement since the PADR).

Table 5-8 lists notional planning level summer limits, mode of failure and limit improvements provided by Option 1D under the same six representative operating conditions as provided for Option 1A above.

Table 5-8 Notional QNI limits and limit improvements following Option 1D – Summer

Operating Condition		Notional Limit (MW)		Change from “Do Nothing” (MW)	
		NSW to QLD	QLD to NSW	NSW to QLD	QLD to NSW
High Sapphire	Day High	365 (Thermal)	1,175 (Thermal)	0	105
	Day Medium	480 (Thermal)	1,110 (Thermal)	0	40
	Day Low	670 (Stability)	940 (Thermal)	0	-10
	Night High	330 (Thermal)	1,150 (Thermal)	0	150
	Night Medium	475 (Thermal)	1,140 (Thermal)	0	150

	Night Low	635 (Stability)	1,030 (Thermal)	0	45
Low Sapphire	Day High	190 (Thermal)	1,335 (Thermal)	0	120
	Day Medium	300 (Thermal)	1,290 (Thermal)	0	85
	Day Low	525 (Stability)	1,125 (Thermal)	0	-5
	Night High	70 (Thermal)	1,360 (Stability)	0	135
	Night Medium	220 (Thermal)	1,330 (Stability)	0	115
	Night Low	445 (Stability)	1,280 (Thermal)	0	70

Table 5-9 lists corresponding notional planning level winter limits for Option 1D.

Table 5-9 Notional QNI limits and limit improvements following Option 1D – Winter

Operating Condition		Notional Limit (MW)		Change from "Do Nothing" (MW)	
		NSW to QLD	QLD to NSW	NSW to QLD	QLD to NSW
High Sapphire	Day High	425 (Thermal)	1,245 (Thermal)	0	175
	Day Medium	570 (Stability)	1,180 (Thermal)	0	110
	Day Low	670 (Stability)	1,025 (Thermal)	0	-5
	Night High	365 (Thermal)	1,175 (Stability)	0	175
	Night Medium	545 (Thermal)	1,155 (Stability)	0	165
	Night Low	635 (Stability)	1,070 (Thermal)	0	85
Low Sapphire	Day High	245 (Thermal)	1,360 (Stability)	0	145
	Day Medium	375 (Stability)	1,330 (Stability)	0	125
	Day Low	525 (Stability)	1,205 (Thermal)	0	5
	Night High	110 (Thermal)	1,360 (Stability)	0	135
	Night Medium	285 (Thermal)	1,330 (Stability)	0	115
	Night Low	445 (Stability)	1,280 (Stability)	0	70

5.5 Information on the technical feasibility of 'virtual transmission line' options

Consultation with proponents of 'virtual transmission line' options since the PADR has resulted in the stated costs of these technologies falling, meaning they are more likely to be considered 'economically feasible'. However, TransGrid and Powerlink note that it would still be necessary to conduct a formal procurement process for those options, either as network or non-network solutions (and, at this stage, issues of required performance and liability are expected to be important).

Moreover, TransGrid and Powerlink note that credible options under the RIT-T are required to be 'technically feasible'. An option is considered technically feasible if there is a high likelihood that it will, if developed, provide the services that the proponent has claimed it could provide for the purposes of the RIT–T assessment (in providing these services, the option should also comply with relevant laws, regulations and administrative requirements).[53]

A proportionate approach to assessing technical feasibility of the 'virtual transmission line' options was adopted in the PADR, which effectively assumed that these options were technically feasible. This approach was taken in order to compare all options simply on their expected net market benefits (i.e., putting aside technical feasibility) and had no bearing on the conclusion at the PADR stage since these options were not found to be the top-ranked options.[54]

This approach has not been taken as part of the PACR since the assessment is required to identify the preferred credible option. A 'virtual transmission line' comprised of grid-connected battery systems and/or braking resistors of this magnitude would be the first in Australia of this scale and there is substantial additional network modelling and testing that is required in order to comprehensibly determine technical feasibility. TransGrid and Powerlink consider that determining whether these solutions are likely to be technically feasible will require around twelve months of additional work and consultation with proponents (Appendix D provides additional detail on the assessment required to determine the 'technical feasibility' of 'virtual transmission line' solutions).

As a consequence, TransGrid and Powerlink have concluded that these 'virtual transmission lines' are not credible options for the purpose of this RIT-T assessment. We consider this approach to be consistent with the draft 2020 ISP conclusion. Specifically, the draft 2020 ISP states that AEMO has tested a number of virtual transmission concepts and has concluded that these are not yet but may very well in future be a viable alternative to traditional transmission infrastructure.[55] We consider it is also consistent with the AER RIT-T Guidelines.[56]

TransGrid and Powerlink envisage that 'virtual transmission lines' may form a potential credible option considered as part of the medium term QNI upgrade recommended in the draft 2020 ISP, for which a PADR is required by 10 December 2021. This timeframe does allow for a comprehensive assessment of the technical feasibility of these options.

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53 AER, *Application guidelines Regulatory investment test for transmission*, December 2018, p. 18.

54 Specifically, at the PADR stage, while Option 5B was the top-ranked BESS option, and had the greatest estimated gross benefit of all options, it was only expected to deliver around 60 per cent of the expected net benefits of Option 1A (on a weighted-basis). This was driven by the relatively high costs associated with Option 5B based on submissions from proponents at the time, which include high upfront costs and as the need to reinvest during the assessment period due to the comparatively shorter life of the energy storage components.

55 AEMO, *Draft 2020 Integrated System Plan Appendices*, 12 December 2019p. 298.

56 In relation to technical feasibility, the AER RIT-T Guidelines provide an example where a RIT-T proponent reasonably believes that an option will not be feasible presently due to the relatively untested nature of the technology at this scale in Australia. In this case, the AER states that this option could be excluded as a credible option due to a lack of technical feasibility. See: AER, *Application guidelines Regulatory investment test for transmission*, December 2018, pp. 18-19.

TransGrid and Powerlink therefore encourage proponents of these solutions to respond to the current draft 2020 ISP consultation, both in relation to:

- the capabilities of these technologies generally (to inform the ISPs consideration of these technologies as network solutions); and
- if they propose non-network solutions.

This will enable consideration of those technologies by AEMO as part of the final 2020 ISP. AEMO's deadline for submissions on the draft 2020 ISP is 21 February 2020 and their deadline for non-network submissions in relation to the QNI medium upgrade is 13 March 2020.[57]

TransGrid and Powerlink would welcome technical discussions with proponents before this date to help inform their submissions. This could include types of models and information which would help inform the technical feasibility of a 'virtual transmission line' solution.

Proponents should provide detailed technical information on their proposed option, including PSSE and PSCAD models and complete technical performance information, to enable them to be fully assessed.

[57] AEMO, *Draft 2020 Integrated System Plan*, 12 December 2019, pp. 16 & 82.

6. Approach to the PACR assessment

Summary of key points:

- This PACR continues to apply the same market modelling results presented in the PADR, which assess the market benefits expected from each option across four reasonable scenarios.
  - The change in net benefits in this PACR therefore reflects changes in costs, rather than changes in modelled benefits.
- The four scenarios reflect a broad range of potential outcomes across the key uncertainties that are expected to affect the future market benefits of the investment options being considered and are generally aligned with the scenarios adopted for the 2020 ISP.
- A range of sensitivity tests have also been investigated in order to further test the robustness of the outcome to key uncertainties.

The transmission investments considered as part of this RIT-T involve long-lived assets, and it is important that the recommended preferred option does not depend on a narrow view of future outcomes, given that the future is inherently uncertain.

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit.[58] It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options in this PACR have been assessed under the same four scenarios as part of the earlier PADR assessment (and over the same assessment period). The four scenarios differ in relation to demand outlook, assumed generator fuel prices, assumed emissions targets, retirement of coal-fired power stations, and generator and storage capital costs. These variables do not reflect all of the future uncertainties that may affect future market benefits of the options being considered but are expected to provide a broad enough 'envelope' of where these variables may reasonably be expected to fall.[59]

We have weighted each scenario equally. In effect this gives many of the assumptions in the AEMO 'neutral' scenario a higher weighting than in the 'slow change' or 'fast change' scenarios (since there are now two variants of the neutral scenario). We consider this appropriate because the low and high scenarios represent a less likely combination of assumptions occurring simultaneously across a range of variables.[60]

Six categories of market benefit under the RIT-T are considered material and have been estimated as part of the economic assessment for the six credible options within this PACR. The PACR continues to apply the same market modelling results presented in the PADR and a separate modelling report was released alongside the PADR that provides greater detail on the modelling approaches and assumptions, including details on the technical constraints adopted.

Appendix G and Appendix H of this PACR outline in more detail the scenarios modelled and approach taken to estimating market benefits (as was presented in sections 6 and 7 of the PADR).

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58 The AER RIT-T Application Guidelines explicitly refer to the role of scenarios as the primary means of taking uncertainty into account. See: AER, RIT-T Application Guidelines, December 2018, p. 42.

59 Moreover, the scenarios vary several variables at a time and do so in an internally consistent manner, as outlined within the AER RIT-T Guidelines. See: AER, *Application guidelines for the regulatory investment tests*, Final decision, December 2018, p. 42.

60 While the results find that Option 1A and Option 1B provide very net benefits on a weighted-basis, we note that Option 1A is expected to provide materially higher net benefits than Option 1B under the neutral scenario (which is considered the most likely scenario of the four scenarios investigated) and the only scenario where Option 1B is expected to deliver materially higher net benefits than Option 1A is the 'neutral + low emissions' scenario (which is a bespoke scenario developed following feedback from TransGrid's NSW & ACT Transmission Planning forum in November 2018). This is discussed further in section 7.5.

7. Net present value results

Summary of key points:

- Uprating the Liddell to Tamworth lines, installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (‘Option 1A’) is expected to deliver approximately $170 million in net benefits over the assessment period – net benefits range from around $40 million to $270 million across the four scenarios.
- The market benefits of all options are primarily derived from the avoided or deferred costs associated with generation and storage – this benefit arises since the expanded transfer capacity between New South Wales (NSW) and Queensland under each option allows existing and new Queensland generation to export to NSW, reducing the need for new investment in NSW.
- The estimated benefits include significant wholesale market cost savings that will put downward pressure on wholesale electricity prices with flow-on benefits to customers.
- These conclusions are robust to a range of sensitivity tests.

7.1 Neutral scenario

The neutral scenario reflects the best estimate of the evolution of the market going forward, including AEMO’s ‘neutral’ demand forecasts, new generator/storage capital and fuel costs, as well as a national emissions reduction of around 28 per cent below 2005 levels by 2030.

Under these assumptions, Option 1A is estimated to deliver approximately $190 million in net benefits. This represents approximately 22 per cent greater net benefits than the second-ranked option (Option 1B).

Figure 3 shows the overall estimated net benefit for each option under the neutral scenario.

Figure 3 – Summary of the estimated net benefits under the neutral scenario

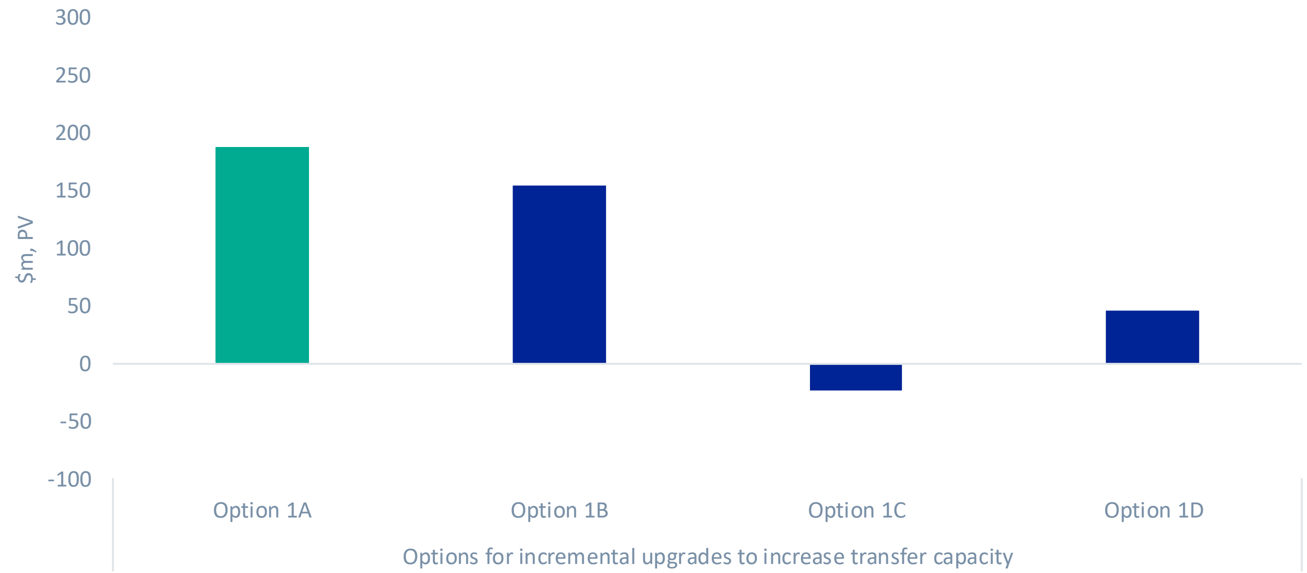
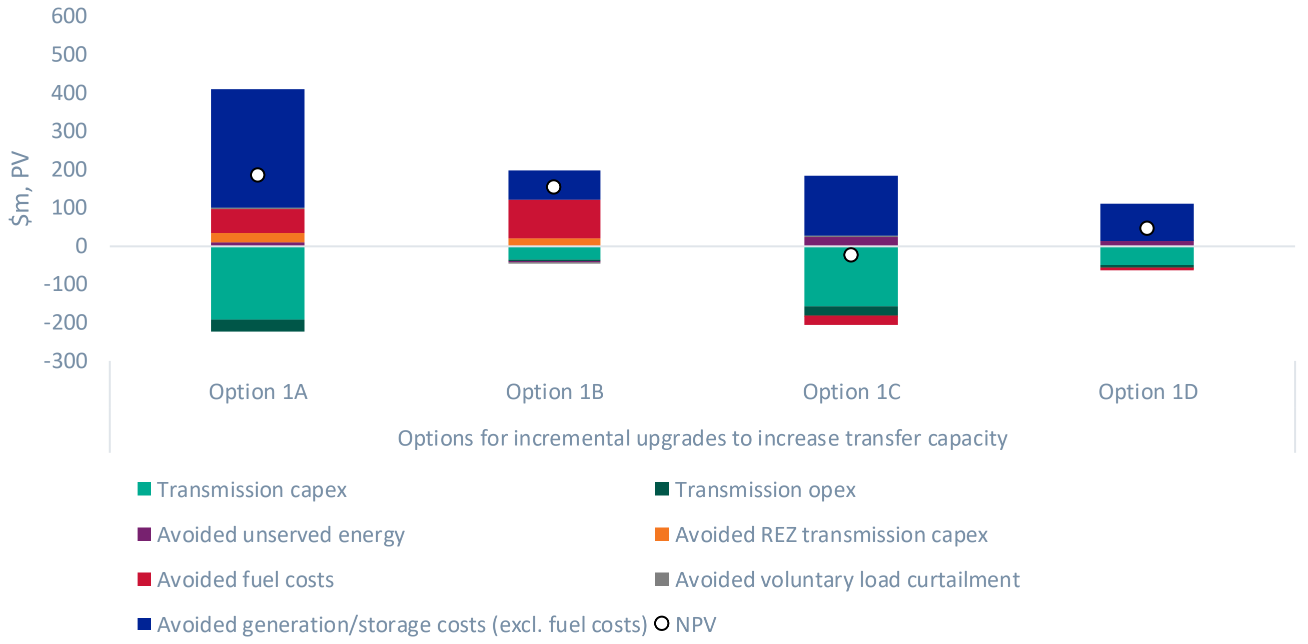


Figure 4 shows the composition of estimated net benefits for each option under the neutral scenario.

Figure 4 – Breakdown of estimated net benefits under the neutral scenario



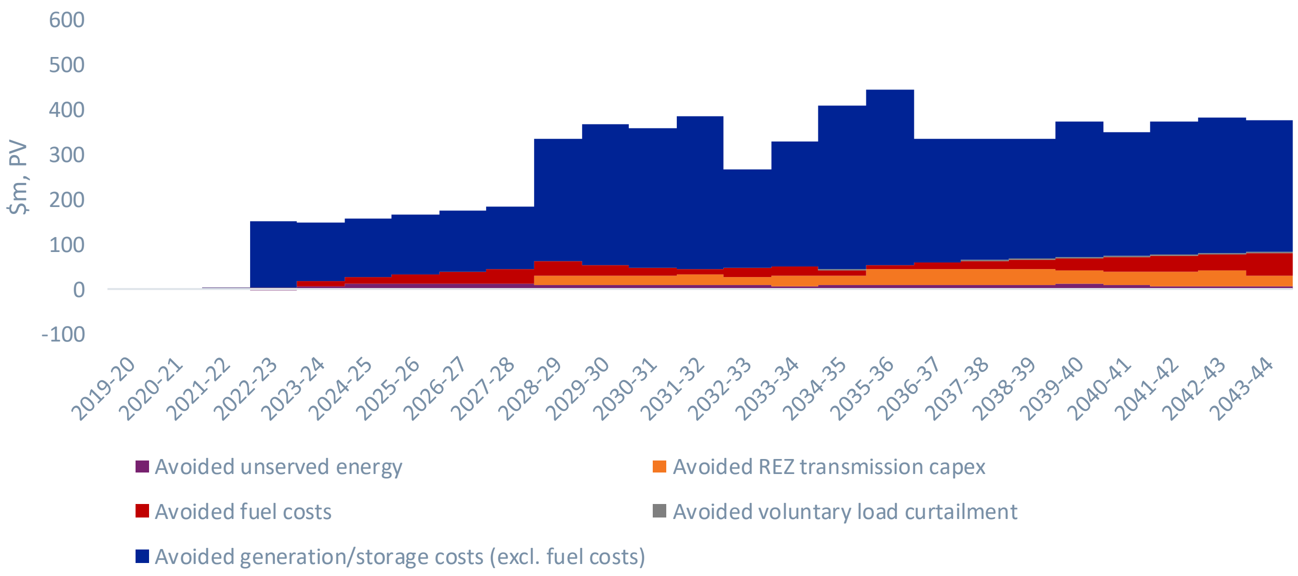
The key findings from the assessment of each option under the neutral scenario are that:

- Market benefits of all options are primarily derived from the avoided or deferred costs associated with generation and storage (shown by the blue bars in Figure 4).
  - This benefit arises since the expanded transfer capacity between NSW and Queensland under each option allows existing and new Queensland generation to export to NSW, reducing the need for new investment in NSW.
  - The benefit of these avoided or deferred costs is linked to the retirement of thermal plants (i.e., avoiding or deferring what would need to be built in their place under the base case) and accrues immediately for all options besides Option 1B (in response to the announced closure of Liddell Power Station).
  - The market modelling finds that Option 1A enables significant investment in new OCGT in NSW to be avoided initially (and across the assessment period), as well as investment in new solar, wind, pumped hydro and large-scale (LS) storage being avoided from around midway through the assessment period.
- Avoided generator fuel costs are the second most material category of market benefit estimated across the options (and are largest for Option 1A and Option 1B).
  - This is driven by existing, relatively modern, coal generators and new renewable generation in Queensland (both of which have relatively lower fuel costs) displacing older NSW coal generation and gas plant (both existing and new).
- Option 1B is estimated to deliver the smallest amount of benefit from avoided or deferred costs associated with generation and storage of all the options.
  - Option 1B offers limited benefit in serving central NSW peak demand following the retirement of Liddell as it does not provide reactive support (and so does not fully unlock the transmission corridor between Queensland and NSW). As a result, in the early years more capacity must be built locally in central NSW to meet peak demand, plus the reserve requirement, with Option 1B compared to Option 1A (which does provide reactive support).
- Option 1C and 1D have the lowest estimated net benefits of the incremental upgrade options.

> This is because these two options do not increase the limit between central and northern NSW, meaning they have limited benefit in serving central NSW peak demand in the near term (and so new capacity must be built locally).

Figure 5 presents the estimated cumulative expected gross benefits for Option 1A for each year of the assessment period under the neutral scenario.[61]

Figure 5 – Breakdown of cumulative gross benefits for Option 1A under the neutral scenario[62]



The timing of the expected gross benefits from the avoided or deferred costs associated with generation and storage are driven by the retirement of thermal plant and therefore when new capacity investment would be required under the base case. Specifically, Figure 5 shows two key market impacts:

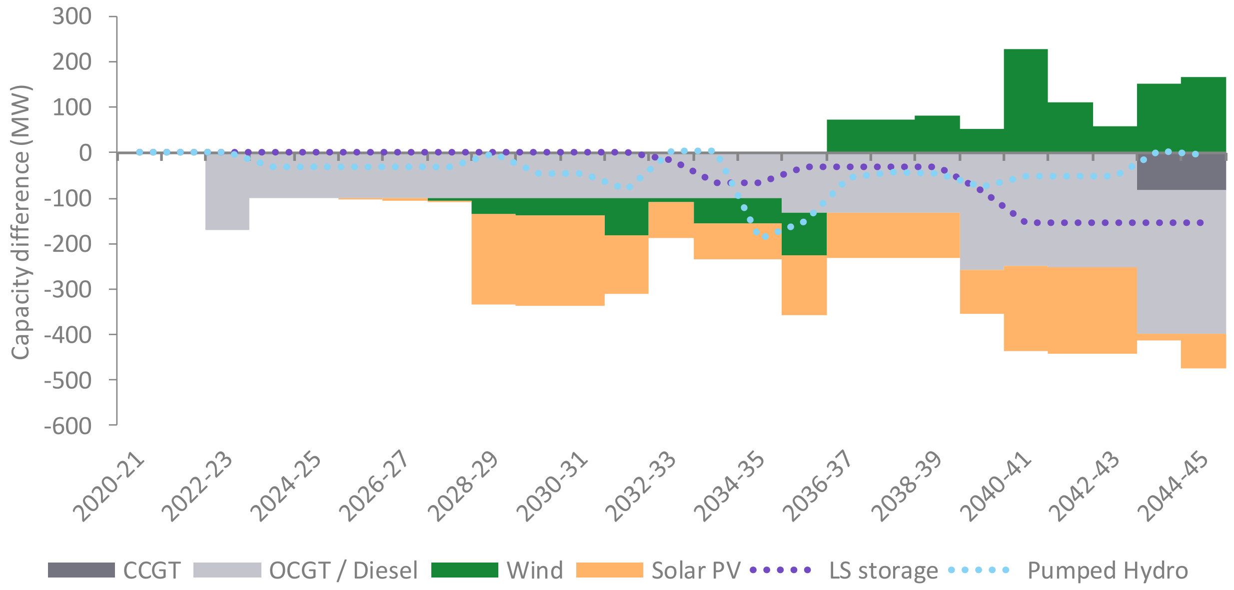
- when Option 1A allows significant investment to be avoided or deferred, i.e., the increases in the blue bars in 2022/23 (when Liddell is expected to retire), 2028/29 (when Vales Point is expected to retire), and 2031/32 and 2035/36 (when Eraring and Bayswater are expected to retire, respectively); and
- when Option1A involves *more* investment in generation and/or storage than the base case (e.g., where this investment in the base case was only deferred rather than avoided) – this is shown by the decreases in the blue bars between years (such as that shown in 2032/33).

Figure 6 summarises the difference in generation and storage capacity modelled for Option 1A (in GW), compared to the base case.

61 Since this figure shows the cumulative gross benefits in present value terms, the height of the bar in 2044 equates to the gross benefits for Option 1A shown in Figure 4 above.

62 While all generator and storage capital costs have been included in the market modelling on an annualised basis, this chart, and all charts of this nature in the PACR, present the entire capital costs of these plant in the year avoided in order to highlight the timing of the expected market benefits. This is purely a presentational choice that TransGrid and Powerlink have made to assist with relaying the timing of expected benefits (i.e., when thermal plant retire) and does not affect the overall estimated net benefit of the options.

Figure 6 – Difference in capacity built with Option 1A, compared to the base case, under the neutral scenario



7.2 Fast-change scenario

The fast-change scenario is comprised of a set of strong assumptions reflecting a future world of high demand forecasts, gas costs, a higher national emissions reduction of around 52 per cent below 2005 levels by 2030, and earlier coal plant retirements compared to the neutral scenario. The fast-change scenario also assumes that the MarinusLink and Battery of the Nation are commissioned (and is the only scenario investigated to do so). The fast-change scenario represents the upper end of the potential range of realistic net benefits associated with the various options.

Under these assumptions, Option 1A is estimated to deliver approximately $270 million in net benefits, which is effectively the same level of net benefits as Option 1B (found to deliver approximately one per cent greater net benefits).

Figure 7 shows the overall estimated net benefit for each option under the fast-change scenario.

Figure 7 – Summary of the estimated net benefits under the fast-change scenario

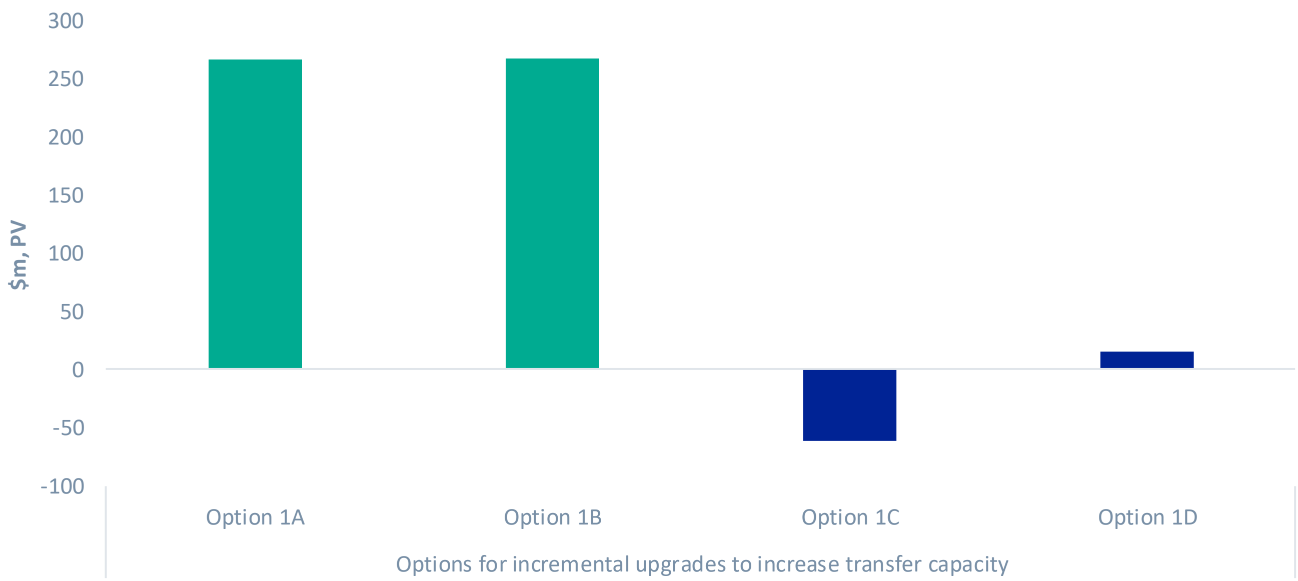
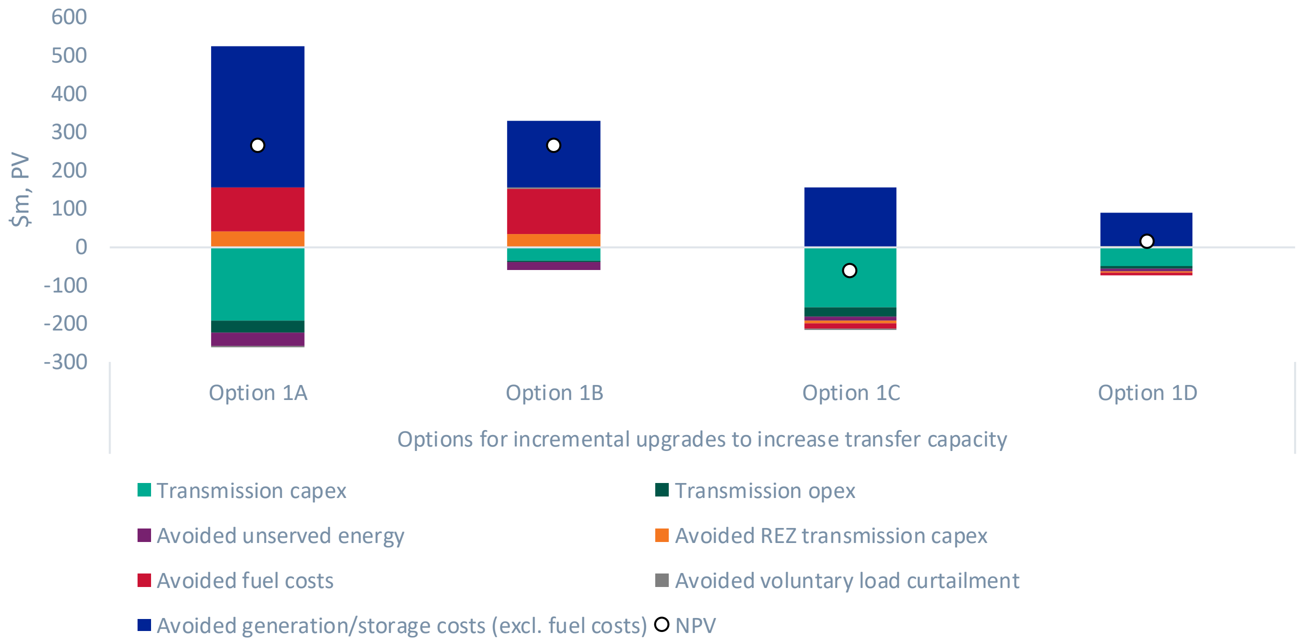


Figure 8 shows the composition of estimated net benefits for each option under the fast-change scenario.

Figure 8 – Breakdown of estimated net benefits under the fast-change scenario

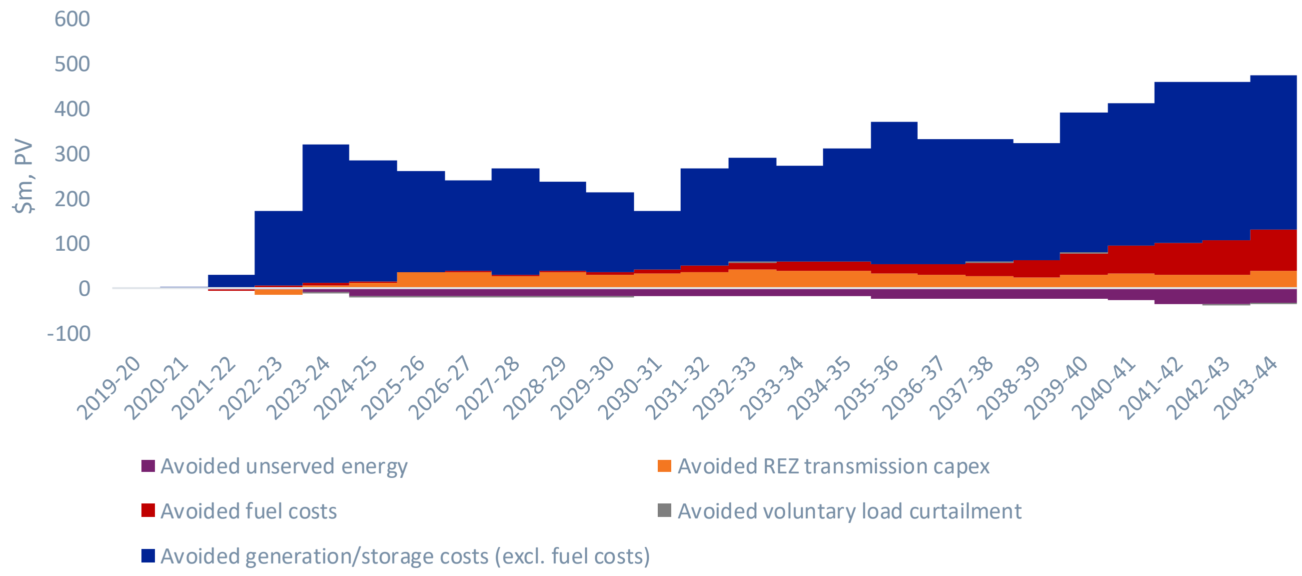


The key findings from the assessment of each option under the fast-change scenario are that:

- The drivers of estimated net benefit remain the same as under the neutral scenario, i.e., the market benefits of all options are primarily derived from the avoided or deferred costs associated with generation and storage.
  - While the market modelling finds that avoided OCGT remains a key driver of this benefit over the assessment period, this scenario also finds that solar, pumped hydro and LS storage are also avoided.
  - The generator fuel costs avoided under this scenario are significantly greater than under the neutral scenario, which is driven by the higher assumed demand forecasts and fuel costs.
- The overall level of benefit is higher for all options under this scenario.
  - The two exceptions to this are Option 1C and Option 1D, which, as outlined in section 7.1 above, both do not increase the limit between central and northern NSW. In the fast-change scenario, there is more solar built in central NSW than in the neutral scenario due to the higher emissions constraint. This additional solar build and the fact that Options 1C and 1D cannot defer/reduce it causes a decrease in the market benefits relative the neutral scenario for these options.
- There is a modest increase in unserved energy under this scenario for all options, compared to the base case (shown by the negative purple bars in Figure 8, Figure 9).
  - This is driven by the interaction between the operation of the generation/storage capacity under this scenario (in response to the higher assumed emissions constraint) and the higher assumed demand forecasts.

Figure 9 presents the estimated cumulative expected gross benefits for Option 1A for each year of the assessment period under the fast-change scenario.

Figure 9 – Breakdown of cumulative gross benefits for Option 1A under the fast-change scenario



7.3 Slow-change scenario

The slow-change scenario is comprised of a set of conservative assumptions reflecting a future world of lower demand forecasts, lower fuel costs, and later coal plant retirements relative to the neutral scenario. The slow-change scenario also excludes the Victoria to NSW interconnector (VNI) upgrade, as well as the planned Snowy 2.0 generation, HumeLink and VNI West[63] developments. The slow-change scenario is intended to represent the lower end of the potential range of realistic net benefits associated with the various options.

Under these conservative assumptions, Option 1A is estimated to deliver approximately $40 million in net benefits. This is around 45 per cent lower than the net benefits estimated for Option 1D, which is the top-ranked option under this scenario.[64]

Figure 10 shows the overall estimated net benefit for each option under the slow-change scenario.

63 Formerly known as KerangLink.

64 While Option 1D is found to have the greatest estimated net benefits under the slow-change scenario, it has very low net benefits under the other three scenarios (as well as on a weighted basis) and so is not considered a contender for the preferred option.

Figure 10 – Summary of the estimated net benefits under the slow-change scenario

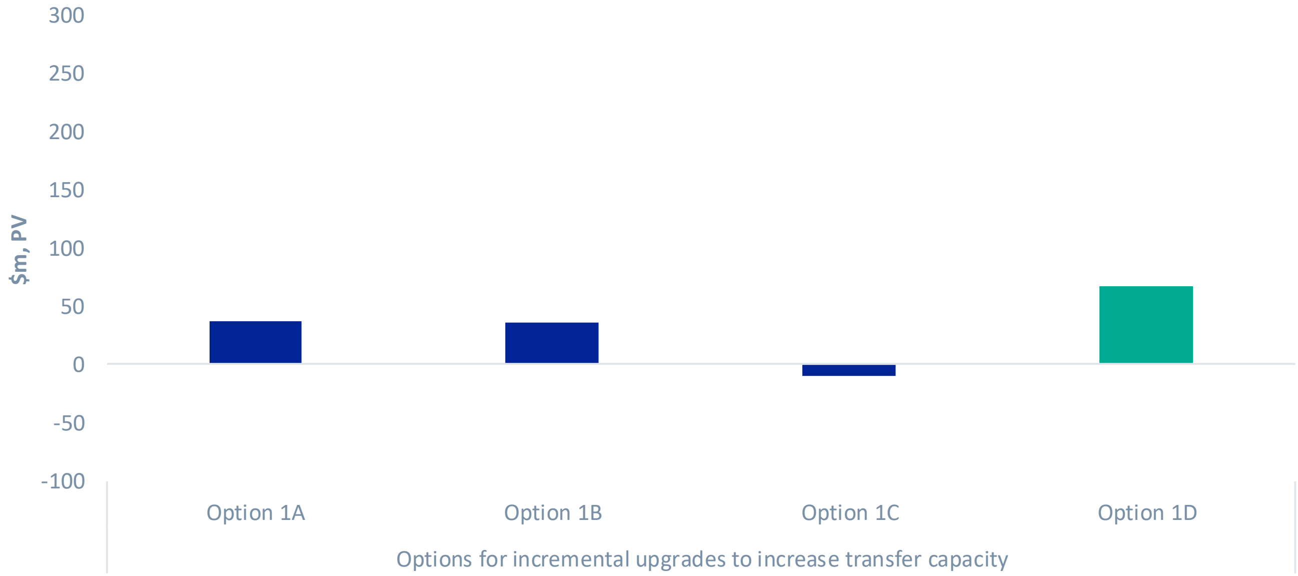
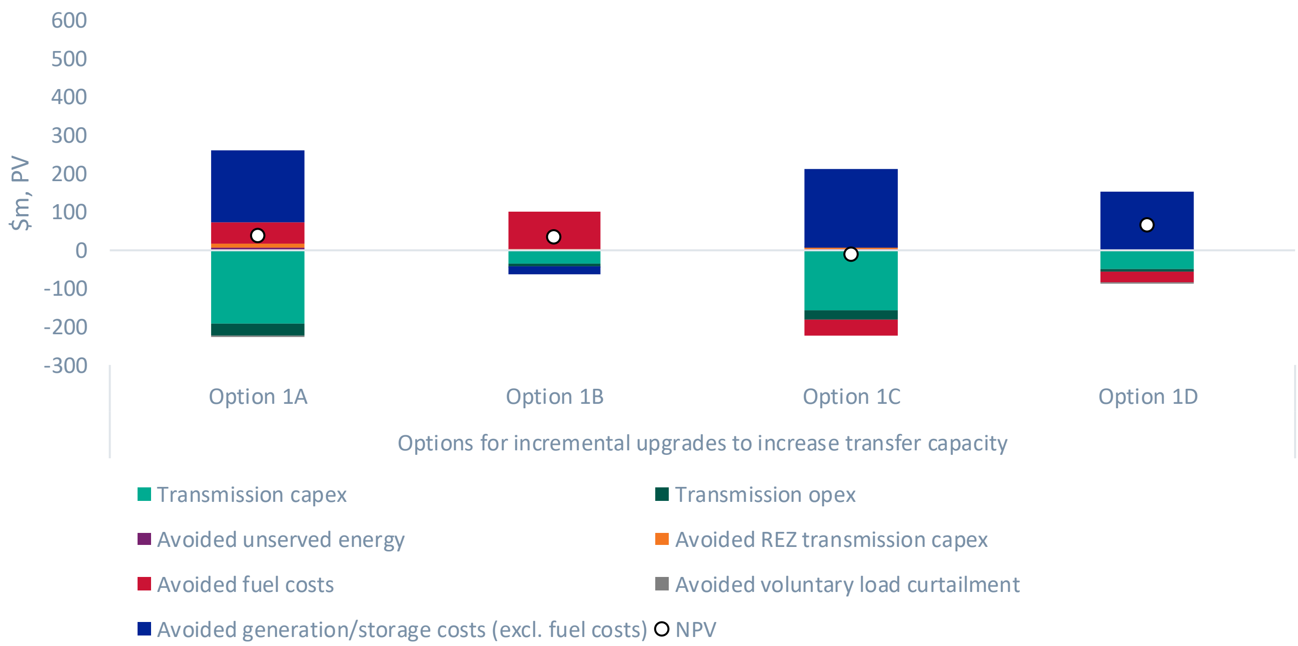


Figure 11 shows the composition of estimated net economic benefits for each option under the slow-change scenario.

Figure 11 – Breakdown of estimated net benefits under the slow-change scenario



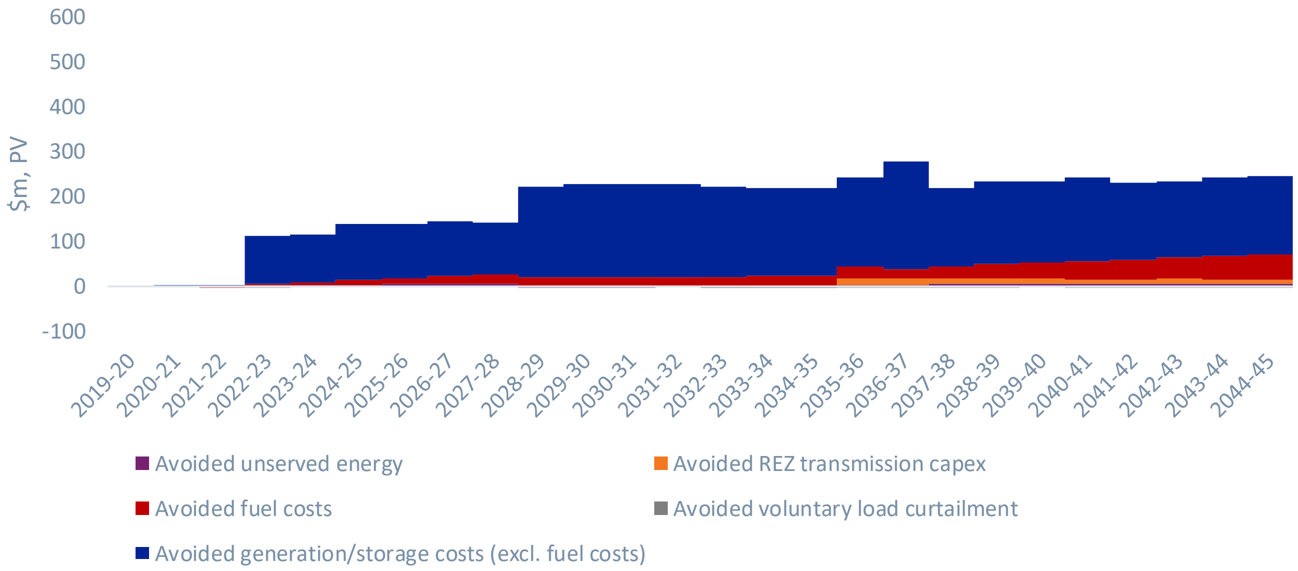
The key findings from the assessment of each option under the slow-change scenario are that:

- The drivers of estimated net benefit remain the same as under the neutral scenario, i.e., the market benefits of all options are primarily derived from the avoided or deferred costs associated with generation and storage.
  - The market modelling finds that this is comprised of mostly avoided OCGT over the assessment period as well as solar, wind and pumped hydro from later in the assessment period for the preferred option.
- The overall level of benefit is expected to be significantly lower for all options under this scenario.

> The two exceptions to this are Option 1C and Option 1D both do not increase the limit between central and northern NSW.[65] Under this scenario, both of these options avoided more solar generation build in central NSW from the mid-2030s (and their benefits increase relative to the neutral scenario).

Even though Option 1D has the greatest net benefits under this scenario, Option 1A is still found to deliver significant net benefits. Figure 12 presents the estimated cumulative expected gross benefits for Option 1A for each year of the assessment period under the slow-change scenario.

Figure 12 – Breakdown of cumulative gross benefits for Option 1A under the slow-change scenario



7.4 'Neutral + low emissions' scenario

The 'neutral + low emissions' scenario adopts all the same assumptions as the neutral scenario with the exception of a stronger emissions reduction target (and a consequent earlier retirement of coal generators). This scenario reflects feedback from TransGrid's NSW & ACT Transmission Planning Forum in November 2018 and is intended to test the robustness of the RIT-T assessment to future emissions policy changes.

Under these assumptions, Option 1A is estimated to deliver approximately the same amount of net benefits as under the neutral scenario (approximately $190 million). This is around nine per cent lower than the net benefits estimated for Option 1B, which is the top-ranked option under this scenario.

Figure 13 shows the overall estimated net benefit for each option under the 'neutral + low emissions' scenario.

65 More detail is set out in section 7.1 of the PADR.

Figure 13 – Summary of the estimated net benefits under the 'neutral + low emissions' scenario

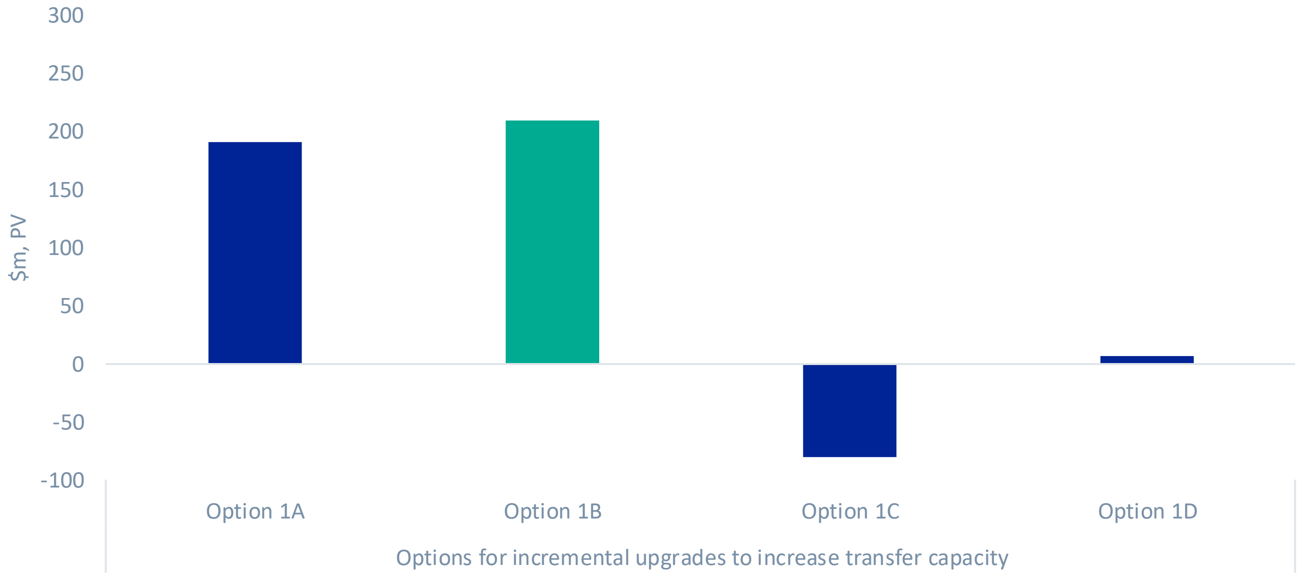
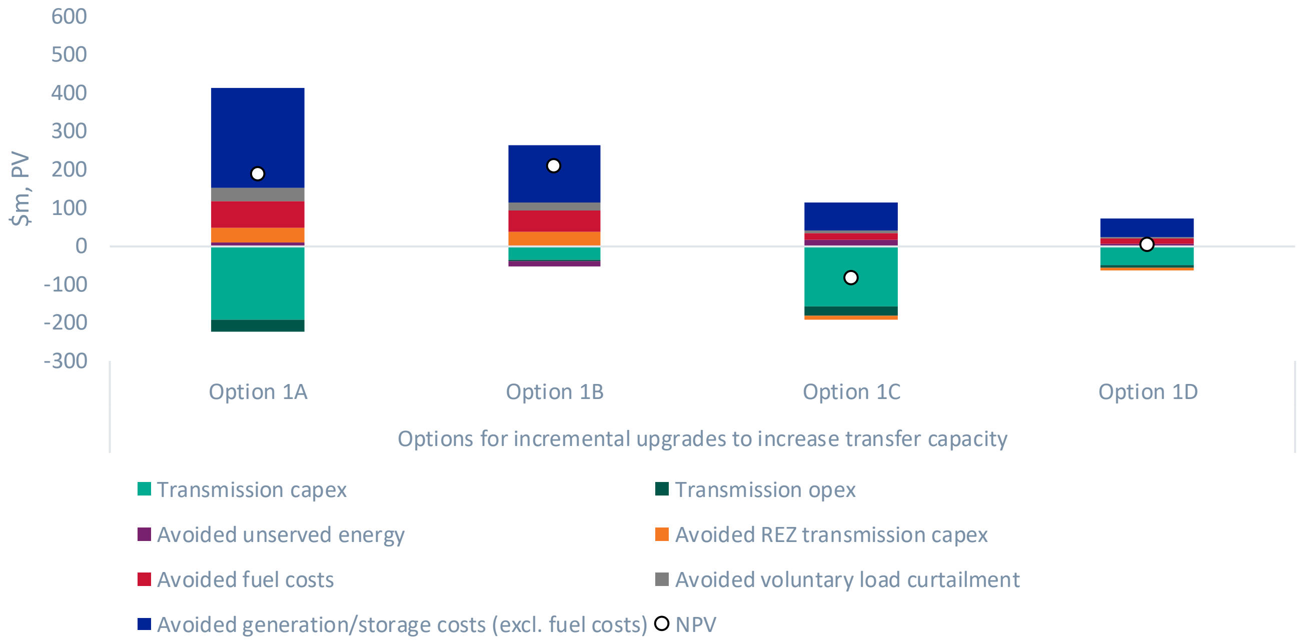


Figure 14 shows the composition of estimated net benefits for each option under the 'neutral + low emissions' scenario.

Figure 14 – Breakdown of estimated net benefits under the 'neutral + low emissions' scenario



The key findings from the assessment of each option under the 'neutral + low emissions' scenario are that:

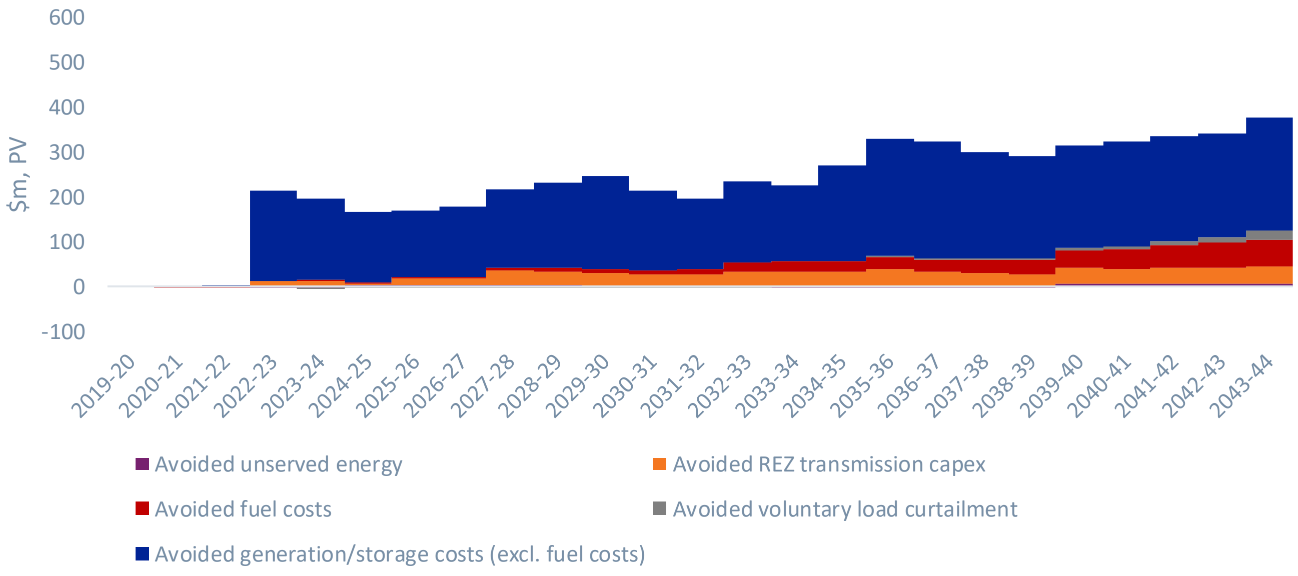
- The drivers of estimated net benefit remain the same as under the neutral scenario, i.e., the market benefits of all options are primarily derived from the avoided or deferred costs associated with generation and storage.
  - > However, the relativities between the specific avoided/deferred investment is different to the neutral scenario on account of what the market modelling finds is built under the base case under this scenario, i.e., a greater level of renewable generation.
  - > Specifically, under the 'neutral + low emissions' scenario, Option 1A still enables significant investment in new OCGT in NSW to be avoided initially (and across the assessment period), but

also avoids more investment in new solar, pumped hydro and large scale (LS) storage on account of more of this generation being built under this scenario's base case than the neutral scenario.

- The relativities between the top-ranked options are reversed.
  - Option 1B's net benefits have increased relative to Option 1A, due to Option 1B enabling more generation to be avoided than under the neutral scenario (whereas Option 1A avoids a very similar amount under these two scenarios).

Even though Option 1B has the greatest net benefits under this scenario, Option 1A is still found to deliver significant net benefits. Figure 15 presents the estimated cumulative expected gross benefits for Option 1A for each year of the assessment period under the 'neutral + low emissions' scenario. While, as with the neutral scenario, there is an increase in the gross benefits in 2022/23 when Liddell Power Station is forecast to retire, the timing of the later benefits associated with retirement of other thermal plant are more staged and brought forward, since this scenario assumes that half of these station capacities are retired two years earlier than under the neutral scenario.

Figure 15 – Breakdown of cumulative gross benefits for Option 1A under the 'neutral + low emissions' scenario

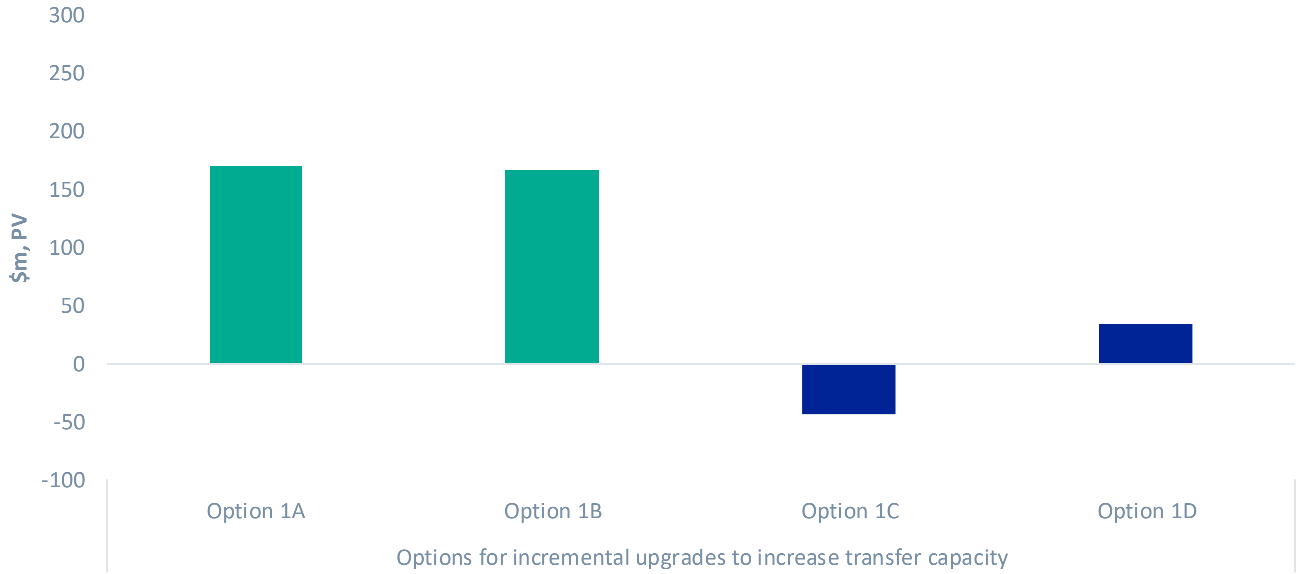


7.5 Weighted net benefits

Figure 16 shows the estimated net benefits for each of the credible options weighted across the four scenarios investigated (and discussed above). Each scenario is weighted equally.

Under the weighted outcome, Option 1A is expected to deliver approximately $170 million of net benefits. As outlined above, the benefits estimated include significant wholesale market cost savings that will put downward pressure on wholesale electricity prices with flow-on benefits to customers.

Figure 16 – Summary of the estimated net benefits, weighted across the four scenarios



While Option 1A is effectively ranked equally with Option 1B on a weighted-basis (which is estimated to provide $167 million of net benefits), TransGrid and Powerlink note that Option 1A is expected to provide materially higher net benefits than Option 1B under the neutral scenario, which is considered the most likely scenario of the four scenarios investigated.

While the four scenarios have been weighted equally above, we have also run a threshold test that investigates the minimum weighting the neutral scenario would need to be given for Option 1A to generate at least five per cent greater net benefits than Option 1B. This threshold test finds that the neutral scenario would need to be given a weighting of at least 36 per cent (with the other three scenarios weighted equally) for Option 1A to deliver at least five per cent greater net benefits than Option 1B on a weighted basis. TransGrid and Powerlink consider this a relatively low percentage (and akin to the perceived likelihood that the neutral scenario will unfold), which adds to the conclusion that Option 1A is the preferred option overall. As noted in section 3.1.4, Origin Energy suggested in their PADR submission that the neutral scenario should be given a greater-than-equal weighting on account of it being the most likely scenario.[66]

The only scenario where Option 1B is expected to deliver materially higher net benefits than Option 1A is the 'neutral + low emissions' scenario. This is a bespoke scenario developed to further stress test the RIT-T assessment following feedback from TransGrid's NSW & ACT Transmission Planning forum in November 2018 (i.e., before the ISP scenarios were finalised). TransGrid and Powerlink consider that the results of this scenario should therefore not be given too much importance in the context of this RIT-T.

Option 1A is also the option assessed and recommended by AEMO in both the 2018 ISP and the draft 2020 ISP.

The cumulative market benefits (on a weighted-basis) from Option 1A's investment are expected to exceed the investment cost (in NPV terms) seven years after the project is energised.

66 Origin submission, p. 2.

7.6 Sensitivity analysis

TransGrid and Powerlink have investigated the following three specific sensitivity tests as part of this PACR:

- the forced outage rates assumed in the market modelling (in response to submission to the PADR);
- higher and lower network capital costs of the credible options; and
- alternate commercial discount rate assumptions

A range of other sensitivity analyses were also presented in the PADR to test the robustness of the modelling outcomes. In particular, the PADR investigated sensitivities involving:[67]

- deferring the retirement of three of Liddell Power Station's units (as announced by AGL earlier in 2019);
- the impact of assuming Wood Mackenzie's 'fast' coal prices, which have been developed for AEMO as part of the 2020 ISP assumptions; and
- the impact of outages during the line uprating work (as raised in submissions to the PSCR).

None of these sensitivities were found to be material and so have not been reproduced for the PACR.

Each of the sensitivity tests undertaken in this PACR are discussed in the sections below.

7.6.1 Forced outage rates

In their submissions to the PADR, Origin Energy[68] and Engie[69] noted that the forced outage rates adopted in the modelling are higher than those assumed by AEMO in the ISP and ESOO. It was suggested that the higher rates could lead to overestimating benefits from higher levels of unserved energy that could be addressed by credible options.

While recognising that the forced outage rate assumptions differ from AEMO's outage rates, the approach EY has taken in the market modelling for this RIT-T is to consider all outages, not just forced outages, to inform generator availability rates. The calculation is based on historical generator performance over the last five years. We consider this approach is more reflective of actual generator outage and availability rates, which leads to more realistic results.

We have however investigated a sensitivity test that assumes AEMO forced outage rates. This sensitivity has involved additional market modelling, undertaken on Option 1A under the neutral scenario, and finds that the impact on overall estimated gross benefits is negligible (a reduction of less than one per cent). The choice of forced outage rate is therefore not considered material for this RIT-T assessment.

7.6.2 Assumed network capital costs

We have tested the sensitivity of the results to the underlying network capital costs of the credible options. Specifically, this includes the full capital cost of the incremental upgrades to the existing networks. Given the similarity between the network options, it is considered reasonable to expect any factors affecting the costs to impact all options equally (i.e., the cost sensitivity is applied across all options).

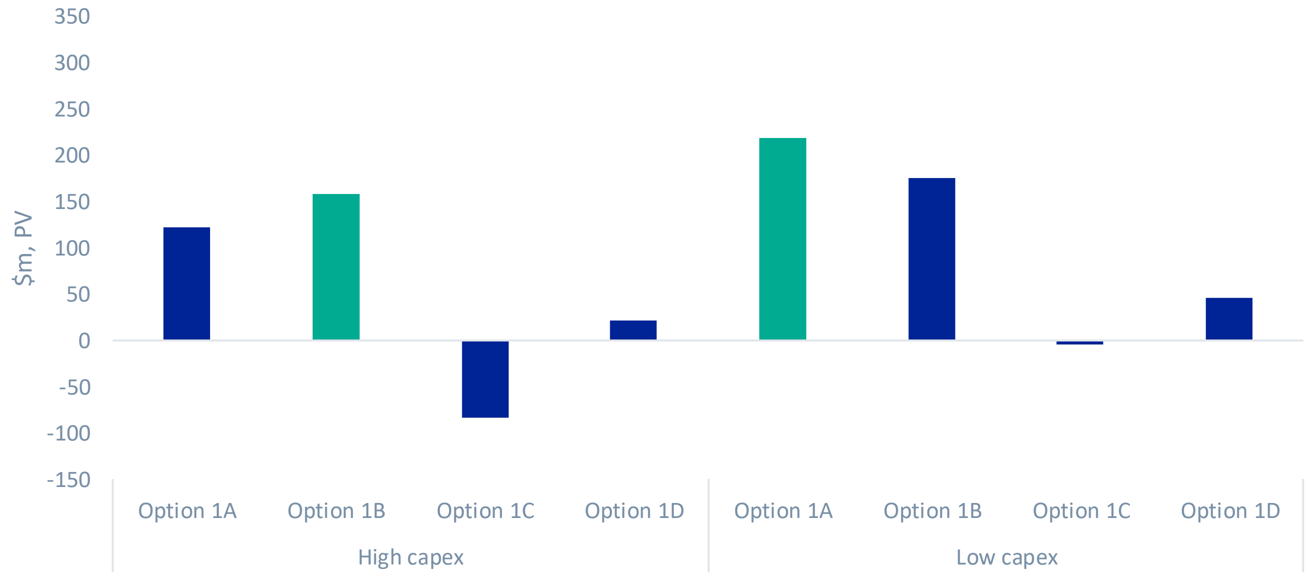
Figure 17 shows that Option 1A continues to provide strongly positive net market benefits under both 25 per cent higher and 25 per cent lower assumed capital costs. While Option 1B is the top-ranked option under 25 per cent higher capital costs, we do not consider this to be a realistic assumption given Option 1A's costs are now known with a high-degree of certainty (i.e., through contracts being entered into with suppliers and contractors).

[67] These are presented in section 8.6 of the PADR.

[68] Origin submission, p. 1.

[69] Engie submission, pp. 2-3.

Figure 17 – Impact of 25 per cent higher and lower network capital costs, weighted NPVs



We have extended this sensitivity testing and find that Option 1A's capital costs would need to be at least 89 per cent higher than the central estimates for it to no longer have positive estimated net benefits (on a weighted-basis). In addition, we find that Option 1B becomes preferred if capital costs are increased by at least 2.4 per cent (but note that, as outlined in section 7.6 above, there are a range of reasons why Option 1A is preferred over Option 1B).

7.6.3 Alternate commercial discount rate assumptions

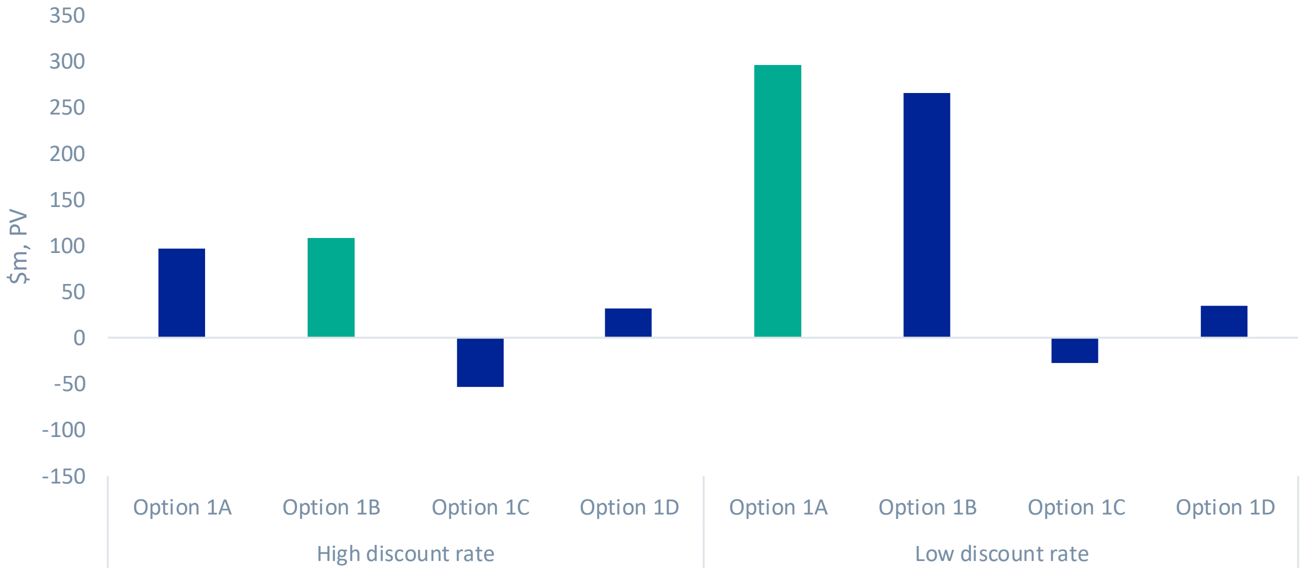
Figure 18 illustrates the sensitivity of the results to different discount rate assumptions in the NPV assessment. In particular, it illustrates two tranches of net benefits estimated for each credible option – namely:

- a high discount rate of 8.95 per cent; and
- a low discount rate of 2.85 per cent.

Option 1A continues to provide strongly positive net market benefits under both alternate discount rate sensitivities investigated.

While Option 1B is marginally preferred over Option 1A when using a high commercial discount rate, we note Option 1A remains preferred over Option 1B under a low discount rate. We therefore do not consider that the high discount rate sensitivity is material to the overall identification of the preferred option.

Figure 18 – Impact of different assumed discount rates, weighted NPVs



We do not find a realistic discount rate that would result in Option 1A having an expected negative estimated net benefit. We find that Option 1B becomes preferred if the commercial discount rate is at least 6.5 per cent (but note that, as outlined in section 7.6 above, there are a range of reasons why Option 1A is preferred over Option 1B).

8. Conclusion

This PACR assessment finds that uprating the Liddell to Tamworth lines, installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (‘Option 1A’) is expected to deliver approximately $170 million in net benefits over the assessment period (on a weighted-basis). While Option 1A is effectively ranked equally with Option 1B on a weighted-basis, TransGrid and Powerlink note that:

- Option 1A is expected to provide materially higher net benefits than Option 1B under the neutral scenario, which is considered the most likely scenario of the four scenarios investigated;
- we have run a threshold test that shows that the neutral scenario would only need to be given a weighting of 36 per cent (with the other three scenarios weighted equally) for Option 1A to deliver at least five per cent greater net benefits than Option 1B on a weighted basis;
- the only scenario where Option 1B is expected to deliver materially higher net benefits than Option 1A is the ‘neutral + low emissions’ scenario, which is a bespoke scenario developed to further stress test the RIT-T assessment following feedback from TransGrid’s New South Wales (NSW) & ACT Transmission Planning forum in November 2018 (i.e., before the ISP scenarios were finalised); and
- Option 1A provides more transmission capacity at times of peak demand in NSW (Option 1B on its own does not increase southerly capacity in NSW at time of peak demand).

Overall, Option 1A is the preferred option identified under this RIT-T. Option 1A is also the option assessed and recommended by AEMO in both the 2018 ISP and the draft 2020 ISP.

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.

Option 1A is expected to provide net benefits to consumers and producers of electricity and to support energy market transition through:

- allowing for more efficient sharing of generation across the NEM, thereby avoiding the use of higher cost generators and deferring, or avoiding, the construction of new, more expensive generation and/or storage capacity;
- continuing to provide reliable supply at the lowest cost by deferring the need to build new generation and storage capacity in New South Wales ahead of the forecast retirement of Liddell Power Station; and
- facilitating the transition to a lower carbon emissions future and the adoption of new technologies through improving access to high quality renewable resources across regions, which further avoids the use of high-cost generators and defers, or avoids, the need to build new generation.

Option 1A is estimated to deliver net benefits of around $170 million assessment period to 2044/45 (in present value terms), which includes significant wholesale market cost savings that will put downward pressure on wholesale electricity prices with flow-on benefits to customers.

The capital costs for Option 1A are estimated to be $230 million and construction is expected to start in March 2020. Delivery and completion of inter-network testing is expected by June 2022.

The cumulative market benefits (on a weighted-basis) from Option 1A’s investment are expected to exceed the investment cost (in NPV terms) seven years after the project is energised.

TransGrid is now in the midst of the pre-investment activities necessary to proceed with the preferred option and will be seeking a determination by the AER that the proposed investment satisfies the RIT-T as well as seeking AER approval of a contingent project allowance for this investment.

While ‘virtual transmission line’ solutions have not been assessed as part of this PACR due to their unproven technical feasibility at this point in time, TransGrid and Powerlink envisage that these technologies may form a potential credible option considered as part of the medium-term QNI upgrade recommended in the 2020 ISP, for which a PADR is required by 10 December 2021. Proponents of these technologies are encouraged to respond to the current draft 2020 ISP consultation, both on the capabilities of their technologies generally (to inform the ISPs consideration of these technologies as network solutions) and if they propose non-network solutions.

Appendix A Checklist of compliance clauses

This section sets out a compliance checklist which demonstrates the compliance of this PACR with the requirements of clause 5.16.4(v) of the National Electricity Rules version 129.

Rules clause	Summary of requirements	Relevant section(s) in PACR
5.16.4(v)	The project assessment conclusions report must include:	-
	(1) the matters detailed in the project assessment draft report as required under paragraph (k)	See below.
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought	3 , Appendix E and Appendix F
5.16.4(k)	The project assessment draft report must include:	-
	(1) a description of each credible option assessed;	5 & Appendix C
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	Appendix F
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	5 & 7
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	Appendix G & Appendix H
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	Appendix H
	(6) the identification of any class of market benefit estimated to arise outside the *region* of the *Transmission Network Service Provider* affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	7
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	7
	(8) the identification of the proposed preferred option;	7 & 8

Rules clause	Summary of requirements	Relevant section(s) in PACR
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a *material inter-network impact* and if the *Transmission Network Service Provider* affected by the RIT-T project has received an *augmentation technical report*, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the *regulatory investment test for transmission*.	8

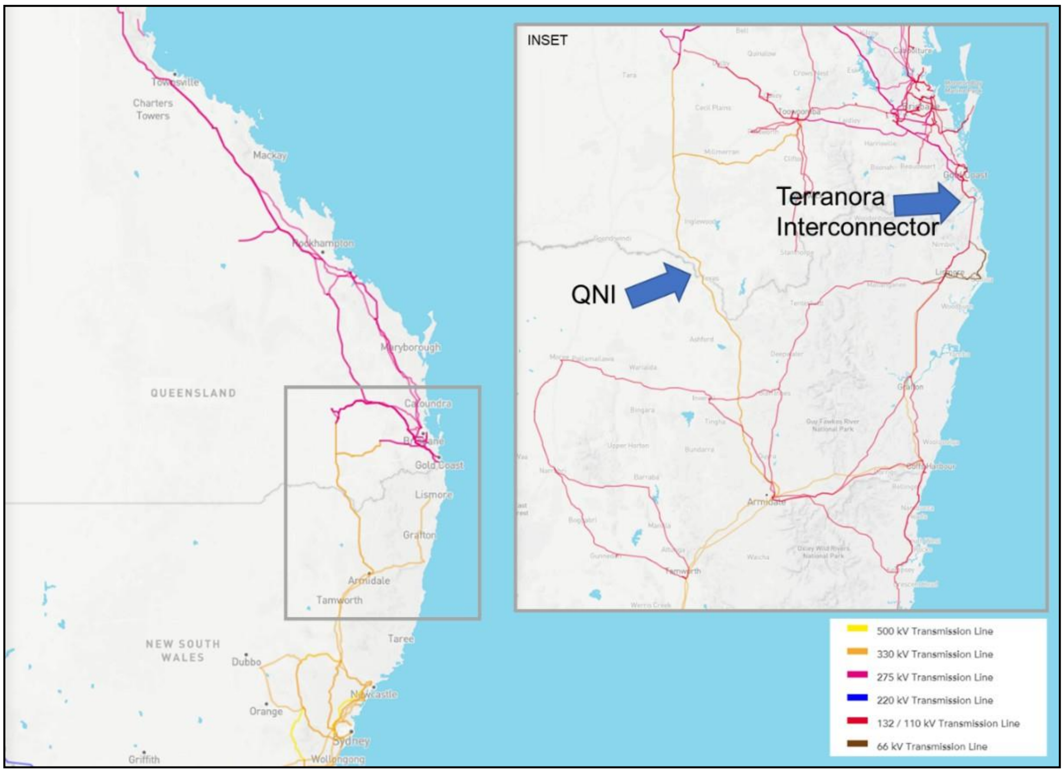
Appendix B Current interconnection between New South Wales and Queensland

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

- Queensland to NSW Interconnector (QNI) – a high voltage alternating current (HVAC) 330kV transmission line connecting two power systems with a nominal transfer capacity of 310 MW from NSW to Queensland ('northwards') and 1,025 MW from Queensland to NSW ('southwards').[70] 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 NSW 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 NSW and southern Queensland are shown in Figure 19, with the two existing interconnectors between the states highlighted.

Figure 19 – Existing transmission networks in Northern NSW and Southern Queensland

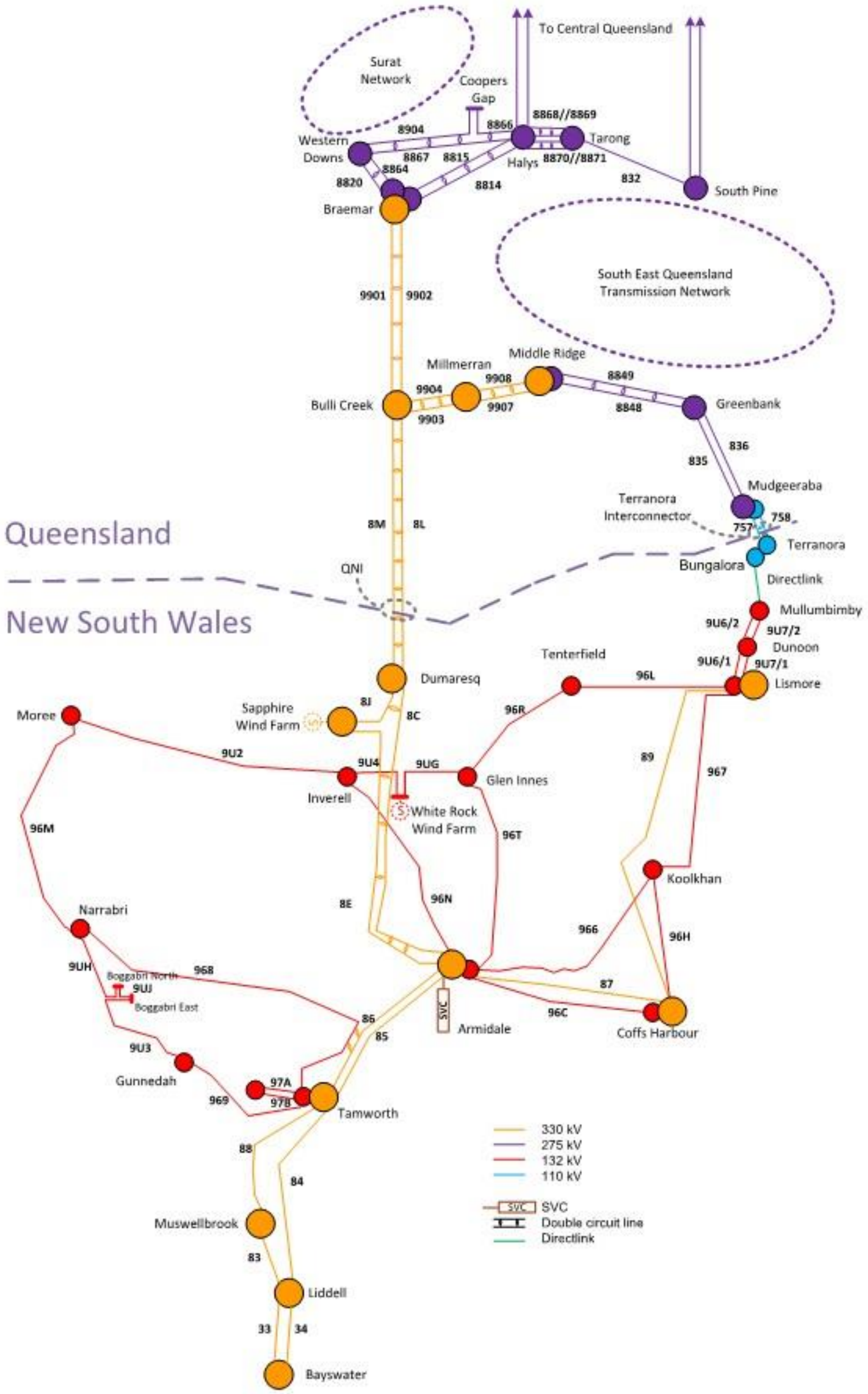


Source: Adapted from the AEMO Interactive Map of Australia's energy infrastructure, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Interactive-maps-and-dashboards

Figure 20 shows a one-line diagram of the relevant transmission network in northern NSW and southern Queensland. It includes line names that are referenced throughout this report.

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

Figure 20 – Specific transmission lines in northern New South Wales and southern Queensland



Appendix C Further detail on options considered at the PADR stage but not progressed

This appendix outlines the further consideration of series compensation. It also summarises two additional options considered but not progressed as part of the earlier PSCR.

The use of series compensation

TransGrid and Powerlink have considered a submission from Smart Wires to the PSCR, proposing series compensation devices to increase the transfer limits on QNI. TransGrid and Powerlink have engaged Manitoba Hydro International to model the application of the devices to QNI, to assess their suitability.

The following observations have been made from the models and application to QNI:

- an increase to transfer limits on QNI requires an increase in several limits – thermal, voltage stability and transient stability for several contingencies;
- the critical response time of an active device to increase stability limits on QNI has been modelled at between 600 to 700ms from fault inception; and
- although modular power flow control devices have been used to control the impedance of a transmission line, which improves sharing over parallel lines in a cut set, they have not yet been developed for applications that increase stability limits.

Although modular power flow control technology is being developed for applications that increase stability limits, it is not currently a sufficiently proven technology for this application.

The timeframes that would be required to further develop the technology mean that such a solution is unlikely to be able to be deployed in time to meet the identified need for near-term options. TransGrid and Powerlink therefore do not consider that for this RIT-T series compensation is a technically feasible option for this RIT-T. This is primarily due to the timeframes in which the identified need needs to be met.

While the use of series compensation has not been assessed as part of this PACR, TransGrid and Powerlink envisage that this technology may form a potential credible option considered as part of the medium-term QNI upgrade recommended in the 2020 ISP, for which a PADR is required by 10 December 2021. Proponents of these technologies are encouraged to respond to the current draft 2020 ISP consultation, both on the capabilities of their technologies generally (to inform the ISPs consideration of these technologies as network solutions) and if they propose non-network solutions.

Options considered but not progressed at the PSCR stage

Two other near-term options have also been considered by TransGrid and Powerlink over the course of this RIT-T to-date. These options have not progressed on the grounds that they are not considered technically feasible, and therefore are not considered to be credible options. A summary of each is provided in Table C-1.

Table C-1 Options considered but not progressed

Option	Overview	Reason(s) it has not been progressed
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.

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. This option is therefore not considered technically feasible.

We note also that upgrading protection systems and a braking resistor in the Hunter Valley (both outlined above) were examined and ruled out as part of the 2014 QNI RIT-T.[71] 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.

[71] 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

Appendix D Additional detail on the assessment required to determine the ‘technical feasibility’ of ‘virtual transmission line’ solutions

A ‘virtual transmission line’ solution would be comprised of BESS at two ends of the QNI corridor (or a BESS at one end and a braking resistor at the other) and a dedicated, highly reliable communication system. Immediately following a contingency, the sending end BESS absorbs power and the ‘receiving-end’ BESS releases the same amount of power minus the line losses. Thus, this ‘virtual transmission line’ concept can manage the overload on remaining parallel transmission lines. The BESS only manages the energy injection in this ‘virtual transmission line’ application. Therefore, there may be voltage issues (especially in the downstream network) due to lack of voltage support when there is an increased QNI transfer, which may necessitate increasing the scope of the ‘virtual transmission line’ to include further voltage control plant. Further steady state assessment of QNI and the distribution network will be required to confirm the voltage issues.

The ‘virtual transmission line’ BESS is proposed to be half an hour operation, as the NER requires AEMO to secure the power system within no more than 30 minutes. Therefore, 30 minute battery duration estimates have been considered to reflect the minimum duration that AEMO may need to restore system security after an incident. Longer durations are contemplated under the NER that if deemed necessary could either double the energy requirement for the batteries or restrict the batteries to be operated fully charged and discharged respectively. This could also mean that the batteries would need to be cycled as southerly and northerly transfer increases are targeted. The specific use of a BESS for this application and operating protocol is yet to be developed with AEMO and will require a collaborative approach over a period of time.

The ‘virtual transmission line’ BESS is capable of managing dynamic voltage stability and transient stability limits in the same way. Following a fault on a line, or trip of a generator or a load in New South Wales or Queensland, the ‘sending-end’ BESS can absorb power and the ‘receiving-end’ BESS can release power to the network, thus increasing the pre-contingency power transfer levels. A special protection scheme (SPS) will be required to be revised when there are changes in the power system, such as renewable generator connections along the 1000km path. In the event of repetitive contingencies due to bushfires, storm etc., it will impose challenges for BESS to be available at full capacity to ensure transient stability. The BESS will only respond to the defined events included in the SPS. Therefore, the BESS will not provide assistance for other events, including multiple contingency events. A significant amount of detailed power system modelling will be required before TransGrid and Powerlink can confirm the performance and viability of the proposed scheme.

To implement a ‘virtual transmission line’ option will also require TransGrid and Powerlink to investigate the detailed communication requirements to ensure such a wide area protection scheme will be feasible. This proposed option requires high speed duplicate communication systems to operate from Gladstone in Queensland to Liddell in NSW (a distance of over 1,000 km). In combination with the modelling requirements both TransGrid and Powerlink will need to investigate the detailed communication requirements to ensure such a wide area protection scheme will be feasible.

Currently, the QNI oscillatory limit is around 1,200 MW in both directions. A high level power system assessment indicates that the thermal, voltage and transient stability limits for the battery option will exceed the QNI oscillatory limit. The BESS could potentially improve the oscillatory limit if it is at the optimum location to be effective in improving the limit.

Battery control interaction with nearby inverter-based generation has not been fully assessed, and this assessment will require a final detailed PSCAD model. In addition, the ‘virtual transmission line’ option will require approval of performance standards. Depending on the combination of services offered by a potential BESS, registration, compliance testing and R2 testing may also be required.

Appendix E Summary of consultation on the PADR

This appendix provides a summary of points raised by stakeholders during the PADR consultation process.

The points raised are grouped by topic and a response is provided to every point raised. All section references are to this PACR, unless otherwise stated.

Table E-1 Summary of points raised in consultation on the PADR

Summary of comment(s)	Submitter(s)	TransGrid and Powerlink response
Comments on the market modelling		
Forced outage rates assumed		
Forced outage rates used were different from AEMO's rates. Explanation on the rationale for deviating from AEMO's forced outage rates would be welcome.	Origin Energy, p 1.	See section 3.1.1 and section 7.6.1.
Origin Energy noted that the method EY adopted to calculate forced outage rates may overstate forced outages as zero dispatches may be due to reasons other than forced outages. Overestimation of outage rates may lead to overestimating net benefits from upgrades. Origin Energy suggested that it may be worth applying different planned maintenance rates to different units as maintenance requirements are not the same for all plants. Similarly, Engie noted that statistical or plant engineering evidence was not presented to justify departure from AEMO's assumptions for forced outage rates, and the high rate is likely to be incorrect/inappropriate. Engie suggests detailed reliability data at plant component, or system, level is needed, including consideration of planned maintenance and refurbishment activities. Classification of forced outages into immediate and deferred categories is also required.	Origin Energy, p 1. Engie, p 2-3.	
Demand assumptions		
The 2018 ESOO was used for demand forecasts in the modelling, which is lower than the 2019 ESOO. Model could be rerun to incorporate 2019 demand forecasts, and if this is not practical, to include a sensitivity analysis for demand.	Origin Energy, p 2.	See section 3.1.2.
Modelling does not include demand shocks (e.g. large energy user shutting down). It may be worth considering such a scenario given the potential for such events to occur in the medium term.	Origin Energy, p 2.	
Other comments on the modelling undertaken		
Consider giving the central scenario higher weighting assuming it is the more likely scenario. It is not clear why each scenario has equal weighting.	Origin Energy, p 2.	See section 3.1.4.
An explanation of the assumptions underpinning fuel price forecasts would be welcome, noting that coal and gas prices were sourced from AEMO's ISP forecasts.	Origin Energy, p 2.	See section 3.1.4.

It is unclear to what extent modelling captures recent transfer capacity reductions due to voltage constraints, and the effect future generation may have on transfer capacity due to additional system security requirements.	Origin Energy, p 2.	See section 3.1.3.
Technical commentary on potential for BESS solutions to manage system security constraints or provide other services will be valuable to clarify expectations for industry.	Tesla, p 4.	See section 3.2.
Comments on the BESS options		
BESS costs		
It is worth exploring additional input scenarios and sensitivities including: • battery capital costs; • battery duration estimates; and • how early retirement of thermal plant may drive timing requirements.	Tesla, p 2.	These tests are expected to be undertaken as part of the 2020 ISP and the forthcoming PADR for the 'QNI medium' upgrade.
BESS operating assumptions		
Recommendation to incorporate 1.6 hour and 2 hour energy storage options as part of the modelling, which could provide energy capacity benefits without increase in costs. This approach aligns with ISP modelling that has been updated from 2018 to now include both 2 hour and 4 hour battery storage variants. Currently 30-minute duration energy storage options have been assumed.	Tesla, p 3.	These operating assumptions are expected to be investigated as part of the 2020 ISP and the forthcoming PADR for the 'QNI medium' upgrade.
The PADR modelling assumes the full power capacity of BESS needs to be reserved for managing interconnector stability limits. As operations become better understood, this assumption may be relaxed and allow BESS to provide other services across multiple markets that driver benefits for BESS options. Services that could be provided include: • premium FCAS services; • VCAS; • virtual inertia; and • MLF improvements.	Tesla, p 4.	
15-year asset life and replacement requires a 'true up' to match the assessment period.	Tesla, p 3.	
Manufacturers are able to offer 20 year warranties on energy storage solutions, compared to the 15 year asset life used in the modelling.	Tesla, p 3-4.	

Furthermore, energy storage assets after 15 or 20 years are not worthless and will still be able to provide value to the grid. Accounting for this value is equivalent to assumptions made for aging coal and gas plants that are still factored into models up to their effective retirement date.		
Other comments		
PIAC agrees the proposed preferred option is Option 1A and is the most desirable option in the RIT-T. PIAC also supports the RIT-T focusing on the short term need identified in the 2018 ISP.	PIAC, p 1.	The PACR continues to focus on the near-term investment need and finds that Option 1A is the preferred option.
PIAC considers it essential to determine the proper risk and cost allocation between industry and consumers and that risks should be borne by those best placed to manage it. To this end, PIAC recommends TransGrid and Powerlink examine the relative accrual of expected benefits to consumers in different NEM regions and compare how costs would be recovered through TUOS.	PIAC, p 1-2	Analysis of risk and cost allocation to consumers in different NEM regions is outside the scope of the RIT-T. However, we understand note that this is currently being reviewed by the AEMC.

Appendix F Summary of consultation on the PSCR

This appendix provides a summary of points raised by stakeholders during the PSCR consultation process.

The points raised are grouped by topic and a response is provided to every point raised. All section references are to the PADR, unless otherwise stated.

While we have included a summary of the points raised on the medium-term option included in the PSCR, we propose to respond to each in detail as part of the separate RIT-T for these options.

Table F-1 Summary of points raised in consultation on the PSCR

Summary of comment(s)	Submitter(s)	TransGrid and Powerlink response
General modelling, results and sensitivities comments		
Transparency and clarity		
As customers pay for network investment and bear the investment risk, any long term network investment and its projected benefits must be sufficiently scrutinised.	EnergyAustralia, p 1.	The PADR includes a range of scenarios designed to test the robustness of the preferred option to a range of different futures. It also investigates a number of select sensitivity tests to further test the robustness of the findings.
Transparent and clear modelling, results, sensitivities and scenarios should be presented to promote stakeholder understanding.	EnergyAustralia, p 1-2.	Sections 6 and 7 of the PADR provide detailed descriptions of the key modelling assumption and approaches adopted, while section 8 of the PADR outlines results of the economic modelling for all options, across all scenarios and sensitivities undertaken. In addition, we have released a range of supplementary material alongside the PADR to help interested stakeholders understand the drivers of the estimated net benefit better.
As much information as possible should be provided to support the PADR and it is important for stakeholders to be able to understand the drivers behind the model results.	EnergyAustralia, p 3.	
PADR should be explicit about whether results are derived by outcomes from modelling itself or whether outcomes were fixed input assumptions.	EnergyAustralia, p 3.	Section 8 of the PADR outlines the key interactions between the market modelling undertaken and the NPV modelling, as well as where the fixed input assumptions have come from (which is primarily from the proposed 2020 ISP inputs developed by AEMO with consultation in early 2019).
The PADR should include information related to the expected range of transfer capability for each of the options over a range of operational conditions.	ERM Power, p 1.	Addressed in section 4.6 and Appendix D of the PADR.
The PADR should include information related to the factors in each case which are expected to limit the transfer capability.	ERM Power, p 1.	
The PADR should include information related to how the transfer capability may change for the addition of blocks of generation output in REZs six to 30 as contained in the PSCR.	ERM Power, p 1.	Appendix D of the PADR summarises the limits to power transfer under the credible options assessed. The generators in REZs six to eight and 30 are not expected to impact stability limits (unless their connection introduces a new critical contingency), but the location of injection will however impact the thermal capacity available for inter-regional transfers. For example, additional generating capacity in REZ 6 would form part of the Queensland generation fleet and would be in competition with other generators to supply the load. Additional generating capacity in REZs 7, 8 and 30 may compete with Queensland generators (or QNI southerly flow) for thermal capacity on the Armidale – Tamworth – Liddell 330kV corridor. This has been

		captured in the market modelling by the northern NSW to north Central limit (NNS-NCEN).
An independent verification of potential transfer capability and limit factors as set out in the PADR should be contained as an appendix.	ERM Power, p 1.	Addressed in section 4.6 of the PADR.
Modelling assumptions		
Should utilise assumptions from the 2019 new ESOO and the next ISP.	EnergyAustralia, p 2; ERM Power, p 2.	The assumptions used in the PADR assessment are based on the planning and forecasting assumptions recently consulted on by AEMO in the context of the 2020 ISP. Where updated assumptions were not available from AEMO by the time the modelling for this RIT-T commenced, our modelling has used use the most recent assumptions that are available (e.g., electricity demand forecasts sourced from the 2018 ESOO). We will consider the impact of any material changes in assumptions since that time in the PACR. The four scenarios investigated include a range of demand forecasts and, at this stage, we have not undertaken a standalone sensitivity test on demand alone as we do not consider that it will affect the identification of the preferred option.
Use of AEMO's 2018 ESOO strong demand forecasts may overstate future demand outcomes for several regions and of an overly conservative nature and sensitivity testing using updated 2018 ESOO neutral demand forecasts should be undertaken.	ERM Power, p 2.	
Modelling should consider the economic viability of all existing power stations.	EnergyAustralia, p 2.	Addressed in section 4.6 of the PADR.
The PSCR indicates that a discount rate of 4.6 per cent will be used and a higher rate seems more appropriate.		
Modelling should not only test the timing of any new network investment but the size and whether it is constructed.		
There will likely be major changes to state based renewable energy targets and policy. Sensitivity analysis should consider these changes.	EnergyAustralia, p 3.	The RIT-T assessment in the PADR uses four scenarios reflecting a broad range of potential outcomes across the key uncertainties that are expected to affect the future market benefits of the options being considered, including future emissions policies. In forming these scenarios, we have drawn on the latest ISP inputs developed and consulted on by AEMO. The variables included in each scenario do not reflect all of the future uncertainties that may affect future market benefits of the options being considered but are expected to provide a broad enough 'envelope' of where these variables can reasonably be expected to fall.
Does the RIT-T cover both Group 1 and Group 2 projects or only Group 1 projects identified in the 2018 ISP?	Stakeholder Webinar, p 1.	Addressed in section 2 of the PADR.
The ESB rule change to allow contingent project process to run concurrently rather than subsequently, when is the decision of this rule change expected to be made?	Stakeholder Webinar, p 2.	Since the PSCR was released, the AER has proposed to adopt an expedited process for considering the contingent project applications for QNI (see section 2.5 of the PADR).

When assessing net market benefits, will you identify the share of benefit allocated between NSW and Queensland consumers, and apportion the of cost?	Stakeholder Webinar, pp 1-2.	Addressed in section 4.7 of the PADR.
How do you propose to reconcile the current approach to the RIT-T with the COGATI report which suggested that there should be distinctive staging of investment?	Stakeholder Webinar, p 2.	It is considered that the refocussed PADR/RIT-T (as outlined in section 2 of the PADR) is consistent with staging the investment. That is, the PADR focuses on near-term investments for increasing transfer capacity (including the 'Group 1' 2018 ISP recommended project), while a subsequent RIT-T process will focus on medium-term investments for increasing transfer capacity (including the 'Group 2' 2018 ISP recommended project).
How would a non-network solution be paid for? i.e. How would the proponent benefit from providing the solution?	Stakeholder Webinar, pp 2-3.	Addressed in section 4.2 of the PADR.
Given interconnector flows have been seen to impact existing generators MLFs close to interconnectors, does the market benefit analysis take into account MLFs?	Stakeholder Webinar, pp 3-4.	Addressed in section 4.6 of the PADR.
Is the 'indicative total transfer capacity' inclusive of Directlink and QNI?	Stakeholder Webinar, p 4.	The options summary table has been updated to clarify that the 'indicative total transfer capacity' referenced is for QNI only and does not include the transfer capability of Directlink.
It was stated during the presentation that current normal transfer capability ranges from 1,000 to 1,100MW south and ~400MW north. Can you advise the equivalent (daytime, medium demand) actual current transfer limits that these augmentation MW values should be measured against?	Stakeholder Webinar, p 4.	Appendix D of the PADR has information on the increases in transfer limits modelled across the options and different operating states. The increases can be subtracted from the limit to obtain the current planning level transfer limit under the given set of conditions.
How broadly can alternative options be considered? For example, other interconnectors or aggressive expansion of local REZ?	Stakeholder Webinar, p 3.	Credible options are bound by meeting the identified need, which is to deliver net benefits to the NEM from increasing the transfer capacity between New South Wales and Queensland. The impact on REZ (and their impact on the NEM) is captured in the wholesale market modelling (as outlined in section 7.1.2 of the PADR).

Firming generation		
Concerned that increased interconnector capacity will not relieve the need for firming capacity across both states for operational security processes.	UPC Renewables, p 1.	Addressed in section 4.6 of the PADR.
RIT-T modelling should capture requirements for firming generation over the timeframe of the studies.	UPC Renewables, pp 1-2.	
Political uncertainty		
The scale of renewable development in the planning system in NSW may have significant implications for the relative value to consumers associated with increasing interconnection capacity.	UPC Renewables, p 2.	Investigating the robustness of the credible options to uncertainty about the future is a key feature of the RIT-T and is captured through the use of a range of reasonable scenarios, as well as sensitivity tests. The scenarios and sensitivities investigated as part of the PADR are discussed in sections 6.1 and 6.3 of the PADR, respectively, and, on balance, we consider that they represent a comprehensive assessment of uncertainty for credible options. In particular, the scenarios include variations in relation to emissions targets. This includes a 52 per cent reduction emissions reduction target applying to the electricity sector in the 'neutral with stronger emissions reduction' and 'fast change' scenarios, which test a policy that encourages renewable development in NSW.
A federal Labor government would likely implement a policy which encourages renewable development in NSW and thus may reduce the export opportunities from Queensland and suppress the benefits associated with exporting renewables energy into NSW.	UPC Renewables, p 2.	
Detailed analysis should wait until uncertainty regarding government is resolved.	UPC Renewables, p 2	Delaying the RIT-T, and any consequent investment, will come at the cost of net benefits to the NEM in the near-term. Moreover, uncertainty will always exist and the RIT-T is designed to deal with uncertainty through the use of reasonable scenarios. The scenarios include variations in relation to emissions targets.
Solar resources are similar between New South Wales and Queensland and so transfer from Queensland may be of limited value, i.e., when transfer occurs it is of dirty coal power from Queensland rather than clean renewable power. In this case, better storage or a wider energy mix in Queensland would be jointly necessary.	UPC Renewables, p 2	Expanding transfer capacity between New South Wales and Queensland increases the ability of new renewable generation to locate in the highest quality areas. The market benefits of all options are primarily derived from the avoided or deferred costs associated with generation and storage, compared to the base case. This benefit arises since the expanded transfer capacity between New South Wales and Queensland under each option allows existing and new Queensland generation (which may be driven by state renewable energy targets) to export to New South Wales, reducing the need for new investment in New South Wales. The market modelling finds that the preferred option enables investment in new OCGT and solar, wind, pumped hydro and large-scale storage to be avoided or deferred. The relativities between the technologies affected depends on the scenario being considered, with scenarios that assume lower emissions reductions

		affecting more gas-fired investment (and scenarios with higher emissions reductions avoiding the costs of installing more renewable technologies).
Other modelling considerations		
Should robustly model the impacts of congestion (the consequence of an unprecedented level of renewable energy investment activity) and present the results and sensitivities to stakeholders in a transparent manner.	EnergyAustralia, p 3.	The market modelling undertaken (as outlined in section 7 of the PADR) models network congestion under each of the options and base case, for each of the scenarios and sensitivities considered. A comparison is then made between the option case and the base case. We have released a range of supplementary material alongside the PADR to help interested stakeholders better understand the drivers of the estimated net benefit and the role congestion plays.
While interconnection will likely provide access to low priced generation from adjacent regions it does not provide additional firm capacity into a region.	EnergyAustralia, p 3.	Addressed in section 4.6 of the PADR.
The RIT-T should consider the impact on the availability of hedging contracts in the NEM.	EnergyAustralia, p 3.	Addressed in section 4.7 of the PADR.
The RIT-T should consider the market impacts of transmission outages that are required to complete the network upgrades.	EnergyAustralia, p 4.	Addressed in section 4.3 of the PADR.
Comments on options proposed		
General comments		
It is critical that options which increase transfer capability in both directions should receive priority for assessment over options which increase transfer capacity in one direction only.	ERM Power, p 1.	We have considered both options that increase capacity in both directions and in a single direction. The framework does not allow for priority to be placed on options based on direction of limit improvement. However, to the extent that a bi-directional increase in transfer capacity provides additional net market benefits, this is taken into account in the analysis.
Series compensation for any of the options has not been considered.	Smart Wires, p 2.	Addressed in section 5.3.1 of the PADR.
Would you consider a preferred option made up of multiple options in the consultation report?	Stakeholder Webinar, p 1.	Scope of Options 1B and 1C combined yields the scope of the preferred option (Option 1A). We have considered combinations of options where logical to do so.
Has series compensation of lines been considered?	Stakeholder Webinar, p 2.	Addressed in section 5.3.1 of the PADR.
Near-term options for increasing transfer capacity		

Option 5 in the PSCR can be delivered in a relatively short time and is also modular and scalable.	WalchaEnergy, p 13.	The two BESS options assessed in the PADR are assumed to be able to commissioned by June 2022, as with the other options. Two different scales have been assessed.
Should consider a variant to Option 5 in the PSCR that utilises a solar farm at Bonshaw in NSW, connected to the grid through Dumaresq substation.	GAIA, p 1.	We have considered this variant as part of the BESS options in the PADR. Due to confidentiality, we only published the generic battery cost for both Option 5A and Option 5 in the PADR.
Option 1B and Option 1C in the PSCR are not adequate, even as a first step.	WalchaEnergy, p 12.	Addressed in section 4.3 of the PADR.
The cut in of Sapphire to circuit 8C is considered essential and may not require a RIT-T.	WalchaEnergy, p 12.	Addressed in section 4.3 of the PADR.
Modular power flow control equipment should be considered to effectively provide series compensation services without causing negative technical restrictions (e.g., Sub-Synchronous Resonance and the exclusion of renewable generation connections along the series compensated line route).	Smart Wires, p 3.	Addressed in section 5.3.1 of the PADR.
Medium-term options for increasing transfer capacity		
Option 2 in the PSCR fails to assist the development of large renewable sources within NSW, especially those of the New England REZ, to replace the retiring Liddell Power Station. It would also consume a potential route that should be developed to a higher transfer capability.	WalchaEnergy, p 12.	These points will be considered further and responded to direct as part of the separate RIT-T process for medium-term options for increasing transfer capacity between NSW and Queensland.
Option 2 in the PSCR should be modified to terminate the 330 KV circuit at Bulli Creek rather than Braemar as the existing system is capable. This modification would have the potential to reduce overall costs to consumers whilst providing the same level of network transfer capacity.	ERM Power, p 1.	
The combination of Option 1A and Option 2 in the PSCR should be considered since it would allow optimisation of voltage and reactive power control infrastructure common to both options.	ERM power, p 2.	
Option 3A in the PSCR is not practicable in terms of environmental impacts and social licence as the ISP description is for a replication of QNI on the same route in close parallel adjacent to the existing QNI. A double circuit line between Bulli Creek and the New England area on a widely separated route would be acceptable but this is not acceptable for northern NSW	WalchaEnergy, p 12.	

as it has ample capacity to generate its only energy from renewable sources.		These points will be considered further and responded to direct as part of the separate RIT-T process for medium-term options for increasing transfer capacity between NSW and Queensland.
Although Option 3C in the PSCR has benefits, Option 3B is preferable at this time as it is more suitable in terms of recognised present needs and has low risk of premature investment compared with Option 3C, which can be further considered at a later stage of grid development.	WalchaEnergy, p 13.	
Option 4A in the PSCR has benefits but will only modestly enhance grid capability.	WalchaEnergy, p 13.	
Option 4B in the PSCR has benefits but does not open up substantial new areas of renewable energy resource.	WalchaEnergy, p 13.	
HVDC options need to mention that Directlink is currently owned by EII and clarify acquisition arrangements.	Energy Infrastructure Investments, p 1.	
Option 4B in the PSCR needs to clarify that the net increase in capacity for this option is 420 MW, i.e., the result of a 600 MW line being built, and 180 MW capacity being removed.	Energy Infrastructure Investments, p 1.	
Although Option 4C in the PSCR may be attractive post 2030, it would be premature to make this connection at the present time.	WalchaEnergy, p 13.	
Should consider an additional option which fully explores the potential to support the development of REZ within each state.	UPC Renewables, p 2-3.	
A key strategy conveyed in the ISP is to develop interconnectors through the renewable energy zones. How will the interconnector be optimised to jointly address expanding renewable energy zones in NSW and reducing congestion between Queensland and NSW?	Stakeholder Webinar, p 3.	
The Tamworth to Armidale line (line 85) must be included and the replacement of line 86 with a new concrete pole line is necessary.	WalchaEnergy, p 12.	
Other comments		
Will there be a reassessment of Stage 2 projects at a later date?	Stakeholder Webinar, p 1.	Addressed in section 2 of the PADR.

Why should consumers pay for new generation connection?	Stakeholder Webinar, p 2.	The options considered as part of this RIT-T do not include regulated investment to fund new generation connections, but rather relieves forecast congestion on the shared transmission network between NSW and Queensland if economic. The options that are being considered in this RIT-T have the characteristics of shared transmission assets and are not expected to be affected by alternative funding models that may be introduced for transmission to connect new generation.
How can proponents assess if future QNI upgrades will affect their MLFs?	Stakeholder Webinar, p 3.	We encourage proponents to engage with AEMO, who publish the methodology for calculating loss factors, as well as the applicable loss factors for each proponent. Further information can be found at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factorand-regional-boundaries
Would TransGrid/Powerlink coordinate separate proposals for non-network solutions? For example if it receives separate load & generator reduction proposals from different proponents on either side of the interconnector.	Stakeholder Webinar, p 4.	We have considered proposals for non-network solutions in combination with other non-network proposals and network solutions where they create a credible option.

Appendix G Ensuring the robustness of the analysis

Summary of key points:

- The RIT-T assessment considers four reasonable scenarios, which differ in relation to demand outlook, assumed generator fuel prices, assumed emissions targets, retirement of coal-fired power stations, and generator and storage capital costs.
- The scenarios reflect a broad range of potential outcomes across the key uncertainties that are expected to affect the future market benefits of the investment options being considered and are generally aligned with the scenarios proposed for the 2020 ISP.
- A range of sensitivity tests have also been investigated in order to further test the robustness of the outcome to key uncertainties.

The transmission investments considered as part of this RIT-T involve long-lived assets, and it is important that the recommended preferred option does not depend on a narrow view of future outcomes, given that the future is inherently uncertain.

Uncertainty is captured under the RIT-T framework through the use of plausible 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. The adoption of different plausible scenarios tests the robustness of the RIT-T assessment to different assumptions about how the energy sector may develop in the future.

The robustness of the outcome is also investigated through the use of sensitivity analysis in relation to key input assumptions. We have identified the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for these factors, beyond which the outcome of the analysis would change.

G1 The assessment considers four 'reasonable scenarios'

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit.[72] It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options have been assessed under four scenarios as part of this PACR assessment. Three of the modelling scenarios are based on AEMO's slow, neutral, and fast scenarios adopted for the 2019 ESOO and 2020 ISP, while the fourth reflects feedback from TransGrid's NSW & ACT Transmission Planning forum in November 2018. The fourth scenario reflects a stronger emissions reduction target coupled with the underlying neutral scenario assumptions and is intended to test the robustness of the RIT-T assessment to future emissions policy changes (we refer to this scenario as the 'neutral + low emissions' scenario throughout this PACR).

[72] The AER RIT-T Application Guidelines explicitly refer to the role of scenarios as the primary means of taking uncertainty into account. See: AER, RIT-T Application Guidelines, December 2018, p. 42.

The table below summarises the specific key variables that influence the net benefits of the options under each of the four scenarios considered. Additional detail and discussion of each scenario is provided in the accompanying market modelling report released alongside the PADR.

The slow change scenario has been amended since the PSCR and now excludes the Victoria to NSW interconnector (VNI) upgrade and the Snowy developments (i.e., Snowy 2.0 generation, HumeLink and VNI West[73]). This approach has been taken to recognise the early stage in commitment and extends the slow change scenario to be an even more robust test of the net benefits that might be expected from the various credible options considered.

Table G-1 Proposed scenario's key drivers input parameters

Key drivers input parameter	Fast change scenario	Neutral scenario	Neutral + low emissions scenario	Slow change scenario
Underlying consumption	AEMO 2018 ESOO strong	AEMO 2018 ESOO neutral	AEMO 2018 ESOO neutral	AEMO 2018 ESOO weak
New entrant capital cost for Wind, Solar, Open-Cycle Gas Turbine (OCGT), Combined-Cycle Gas Turbine (CCGT), Pumped Hydro Storage, and Batteries	AEMO Feb 2019 '2 degree' scenario. '4 degree' scenario for Pumped Hydro.	AEMO Feb 2019 '4 degree' scenario.		
Retirements of coal fired power stations[74]	Half of station's capacity retired 5 years earlier than Neutral. Liddell 2022 fixed	Retired by AEMO Feb 2019 announced retirement date or end-of-technical-lives, except Eraring 2031. Liddell 2022 fixed	Half of station's capacity retired 2 years earlier than Neutral. Liddell 2022 fixed	Half of station's capacity retired 5 years later than Neutral. Liddell 2022 fixed
Gas fuel cost	AEMO Feb 2019 Fast Change forecast	AEMO Feb 2019 Neutral forecast		AEMO Feb 2019 Slow Change forecast
Coal fuel cost	AEMO Aug 2019 Neutral forecasts			AEMO Aug 2019 Slow Change forecasts
Federal Large-scale Renewable Energy Target (LRET)	33 TWh by 2020 to 2030 (including GreenPower and ACT scheme).			
COP21 commitment (Paris agreement)	52% reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 90% reduction of 2005 emissions by 2050	28% reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 70% reduction of 2016 emissions by 2050	52% reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 90% reduction of 2005 emissions by 2050	28% reduction from 2005 by 2030, then a linear extrapolation beyond 2030 to 70% reduction of 2016 emissions by 2050

73 Formerly known as KerangLink.

74 Higher levels of renewable energy generation create an oversupply during certain periods of the day, displacing conventional generation and result in earlier retirement. This phenomenon is amplified in a high load growth scenario, with correspondingly higher levels of renewable energy generation.

Key drivers input parameter	Fast change scenario	Neutral scenario	Neutral + low emissions scenario	Slow change scenario
VRET	25% renewable energy by 2020[75], 40% renewable energy by 2025 and 50% renewable energy by 2030			
QRET	50% by 2030			
South Australia Energy Transformation RIT-T	The proposed SA to NSW interconnector is assumed commissioned by July 2023[76] Project EnergyConnect 800 MW bi-directional VIC-SA 750 MW bi-directional Combined Heywood + EnergyConnect 1,300 MW bi-directional			
Western Victoria Renewable Integration RIT-T	The preferred option is assumed commissioned by 2023			
MarinusLink and Battery of the Nation	Assumed commissioned by July 2033 600 MW bi-directional	Excluded		
Victoria to NSW Interconnector Upgrade	The preferred option is assumed commissioned by July 2020 North 870 MW, South 400 MW			Excluded
Snowy 2.0 generation, HumeLink and VNI West	Snowy 2.0 generation and HumeLink will be included by 2025 The preferred VNI West ISP option is assumed commissioned by July 2026[77] North 2,800 MW, South 2,200 MW			Excluded

These variables do not reflect all of the future uncertainties that may affect future market benefits of the options being considered but are expected to provide a broad enough 'envelope' of where these variables may reasonably be expected to fall. Moreover, the scenarios vary several variables at a time and do so in an internally consistent manner, as outlined within the AER RIT-T Guidelines.[78]

While all scenarios listed above assume that Liddell Power Station retires completely in 2022, consistent with expectations at the time the PADR modelling assumptions were finalised, we note that AGL announced on 2 August 2019 that it now plans to defer retiring three of Liddell's four units until April 2023 (the one other unit will still retire in April 2022).[79] While this deferred retirement for these three units has not been able to be reflected fully in the PACR or PADR analysis (due to the recent timing of the announcement), we have included a sensitivity that investigates the effects of this retirement schedule as part of our sensitivity testing in the PADR.

AEMO are proposing to apply Wood Mackenzie's 'fast' coal price scenario only for their 'step change' scenario, and not within their slow, neutral, and fast scenarios. While we note that the 'fast' coal price scenario has lower coal prices than the neutral coal price scenario (and that the labelling of 'fast' refers to assumed economic conditions and not coal prices specifically), we carried out a sensitivity in the PADR to investigate the impact to Wood Mackenzie's 'fast' coal price scenario.

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75 All successful reverse auction projects are included as listed in the AEMO February 2019 assumptions.

76 ElectraNet's *"SA Energy Transformation RIT-T Project Assessment Draft Report,"* available at https://www.electranet.com.au/projects/south-australian-energy-transformation/, has options for new South Australia New South Wales interconnected commissioned between 2022 and 2024.

77 Consistent with: AEMO, *Building power system resilience with pumped hydro energy storage – An Insights paper following the 2018 Integrated System Plan for the National Electricity Market*, July 2019, p. 16.

78 AER, *Application guidelines for the regulatory investment tests*, Final decision, December 2018, p 42.

79 https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2019/august/schedule-for-the-closure-of-agl-plants-in-nsw-and-sa

Where updated assumptions were not available from AEMO at the time that market simulations for this RIT-T commenced, our modelling has used the most recent assumptions that were available (e.g., electricity demand forecasts sourced from the 2018 ESOO), either from AEMO or from alternative sources. We considered the impact of any material changes in assumptions since that time in the PACR and PADR and did not note any changes in timing of any material coincident developments change (e.g., the proposed new interconnector between New South Wales and South Australia[80]) prior to this PACR's publication.

G2 Weighting the reasonable scenarios

We have weighted each of the above scenarios equally (i.e., 25 per cent each).

In effect this gives many of the assumptions in the AEMO 'neutral' scenario a higher weighting than in the 'slow change' or 'fast change' scenarios (since there are now two variants of the neutral scenario). We consider this appropriate because the low and high scenarios represent a less likely combination of assumptions occurring simultaneously across a range of variables.

While the above probabilities have been applied to weight the estimated market benefits and identify the preferred option across scenarios (illustrated in section 7.5), we have also carefully considered the results in each scenario in section 6.

G3 Sensitivity analysis

In addition to the scenario analysis, we considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing.

The range of factors tested as part of the sensitivity analysis in the PADR were:

- the deferred retirement of three of Liddell Power Station's units (as recently announced by AGL);
- the impact of assuming Wood Mackenzie's 'fast' coal prices, which have been developed for AEMO as part of the 2020 ISP assumptions;
- the effect of including outages during line uprating (as raised in submissions to the PSCR);
- capital costs of the credible options; and
- alternate commercial discount rate assumptions.

The results of these sensitivities are discussed in the PADR.

Sensitivity analysis have also been considered in this PACR:

- forced outage rates;
- capital costs of the credible options; and
- alternate commercial discount rate assumptions.

As part of this, we identified the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for these factors beyond which the outcome of the analysis would change. The results of these sensitivities are presented in section 7.6.

The above list of sensitivities represents a focus on the key variables that could impact the identified preferred option.

80 However, we note that on 29 August 2019, New South Wales government signalled its intention to fast-track the development of this interconnector after awarding the project 'critical infrastructure' status, see: Macdonald-Smith, A., & S. Evans, *NSW-SA power cable to be fast-tracked*, 29 August 2019, Financial Review, accessed 30 August 2019: https://www.afr.com/companies/energy/nsw-sa-power-cable-to-be-fast-tracked-20190828-p52lpk

Appendix H Estimating the market benefits

Summary of key points:

- Six categories of market benefit under the RIT-T are considered material and have been estimated as part of the economic assessment for the six credible options within this PACR consistent with market benefits estimated in the PADR.
- Wholesale market dispatch modelling has been used to estimate these categories of market benefits.
- The market modelling assumptions and inputs used in the PACR have not been updated since the PADR as doing so is not expected to have a material impact on the preferred option identified.
- A separate modelling report was released alongside the PADR that provides greater detail on the modelling approaches and assumptions, including details on the technical constraints adopted.

As outlined in section 2, the key benefits expected from expanding transfer capacity are driven by anticipated changes in wholesale market outcomes going forward.

The RIT-T requires categories of market benefits to be calculated by comparing the 'state of the world' in the base case where no action is undertaken, with the 'state of the world' with each of the credible options in place, separately. The 'state of the world' is essentially a description of the NEM outcomes expected in each case, and includes the type, quantity and timing of future generation investment as well as unrelated future transmission investment (e.g., that required to connect REZs).

A wholesale market dispatch modelling approach has been applied to estimate the market benefits associated with each credible option included in this RIT-T assessment.[81]

This section first outlines the specific categories of market benefit that are expected from expanding transfer capacity between New South Wales and Queensland transfer capacity in the near-term, before providing an overview of the wholesale market modelling undertaken.

We published a separate modelling report alongside the PADR that provides greater detail on the modelling approach and assumptions, to provide transparency to market participants.

H1 Expected market benefits from expanding transfer capacity

The specific categories of market benefit under the RIT-T that have been modelled as part of this PACR are:

- changes in fuel consumption in the NEM arising through different patterns of generation dispatch;
- changes in costs for parties, other than the RIT-T proponent (i.e., changes in investment in generation and storage);
- differences in unrelated transmission investment;
- changes in involuntary load curtailment;
- changes in voluntary load curtailment; and
- changes in network losses.

The approach taken to estimating each of these market benefits is outlined below and discussed in greater detail in the accompanying market modelling report.

[81] The RIT-T requires that in estimating the magnitude of market benefits, a market dispatch modelling methodology must be used, unless the TNSP(s) can provide reasons why this methodology is not relevant. See: AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 11, p. 6.

Changes in costs for other parties and fuel consumption in the NEM

The first two categories of market benefits listed at the start of section H1 above are expected where credible options result in different patterns of generation dispatch and future construction (and retirement) of generators and large-scale storage across the NEM, compared to the base case.

In particular, the primary effects of the credible options are a reduced need for new generation and/or storage to be built in New South Wales once Liddell retires, and avoided generator fuel costs by allowing greater use of existing relatively modern coal-fired generation and renewable energy development in Queensland. As shown in section 8 below, this is the largest category of benefit estimated.

Differences in unrelated transmission costs

This benefit category relates to the costs of intra-regional transmission investment associated with the development of REZs that could be avoided if a credible option is pursued.

AEMO has identified a number of REZs in various NEM jurisdictions as part of the 2018 ISP and has included allowances for transmission augmentations that it considers would be required to develop those REZs. The credible options being considered in this RIT-T could potentially allow development of some of these REZs without the need for additional intra-regional transmission investment.

While the impact of the credible options on these costs has been included in the wholesale market modelling for both the PADR and this PACR, we note that these have not been found to be material. Instead, it is expected that these benefits will likely be more material for the medium-term options for increasing transfer capacity between New South Wales and Queensland outlined in the PSCR (e.g., the 2018 'Group 2' recommended option), and will be investigated further as part of the subsequent RIT-T focussing on these medium-term options.

Changes in involuntary load curtailment

Increasing the transfer capacity between Queensland and New South Wales increases the generation supply availability from the rest of the NEM to each of these states during certain times. This will provide greater reliability for each state by reducing the potential for supply shortages and the consequent risk of involuntary load shedding.

This market benefit involves quantifying the impact of changes in involuntary load shedding associated with the implementation of each credible option via the time sequential modelling component of the market modelling. Specifically, the modelling estimates the MWh of unserved energy (USE) in each trading interval over the modelling period, and then applies a Value of Customer Reliability (VCR, expressed in $/MWh) to quantify the estimated value of avoided USE for each option. We have adopted AEMO's standard assumptions for VCR for the purposes of this assessment.

This category of market benefit has been found to be relatively small within the market modelling. This is due to there not being a material difference in the quantity of involuntary load shedding between each option and the base case, under each of the scenarios.

Changes in voluntary load curtailment

Voluntary load curtailment is when customers agree to reduce their load once pool prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances. Where the implementation of a credible option affects pool price outcomes, and in particular results in pool prices reaching higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment.

This class of market benefit has also been found to be relatively low within the market modelling, reflecting that the level of voluntary load curtailment currently present in the NEM is not significant.

Changes in network losses

The time sequential market modelling has taken into account the change in network losses that may be expected to occur as a result of the implementation of any of the credible options, compared with the level of network losses which would occur in the base case, for each scenario.

The benefit of changes to network losses are captured within the dispatch cost benefits of avoided fuel costs and changes to voluntary and involuntary load shedding.

While the changes in losses have been implicitly included in the wholesale market modelling of other market benefits, we note that the change in network losses between the base case and the options are not expected to be material for the options considered. The materiality of network losses is expected to be greater for the medium-term upgrade options and will be investigated further as part of the subsequent RIT-T focussing on these options.

H2 Wholesale market modelling has been used to estimate market benefits

TransGrid and Powerlink have engaged EY to undertake the wholesale market modelling to assess the market benefits expected to arise under each of the credible options and scenarios.

EY has applied a linear optimisation model and performed hourly, time-sequential, long-term modelling for the NEM to estimate categories of wholesale market benefits expected under each of the options. Specifically, EY has undertaken two separate market simulation exercises, namely:

- Long-term Investment Planning – identifies the optimum generation (including storage) and unrelated transmission infrastructure development schedule, while meeting reliability requirements, policy objectives, and technical generator and network performance limitations; and
- Market Dispatch Simulation – mimics AEMO's NEM Dispatch Engine ('NEMDE') by determining the least-cost hourly dispatch of generation to meet forecast demand while observing the technical capabilities of generation and network.

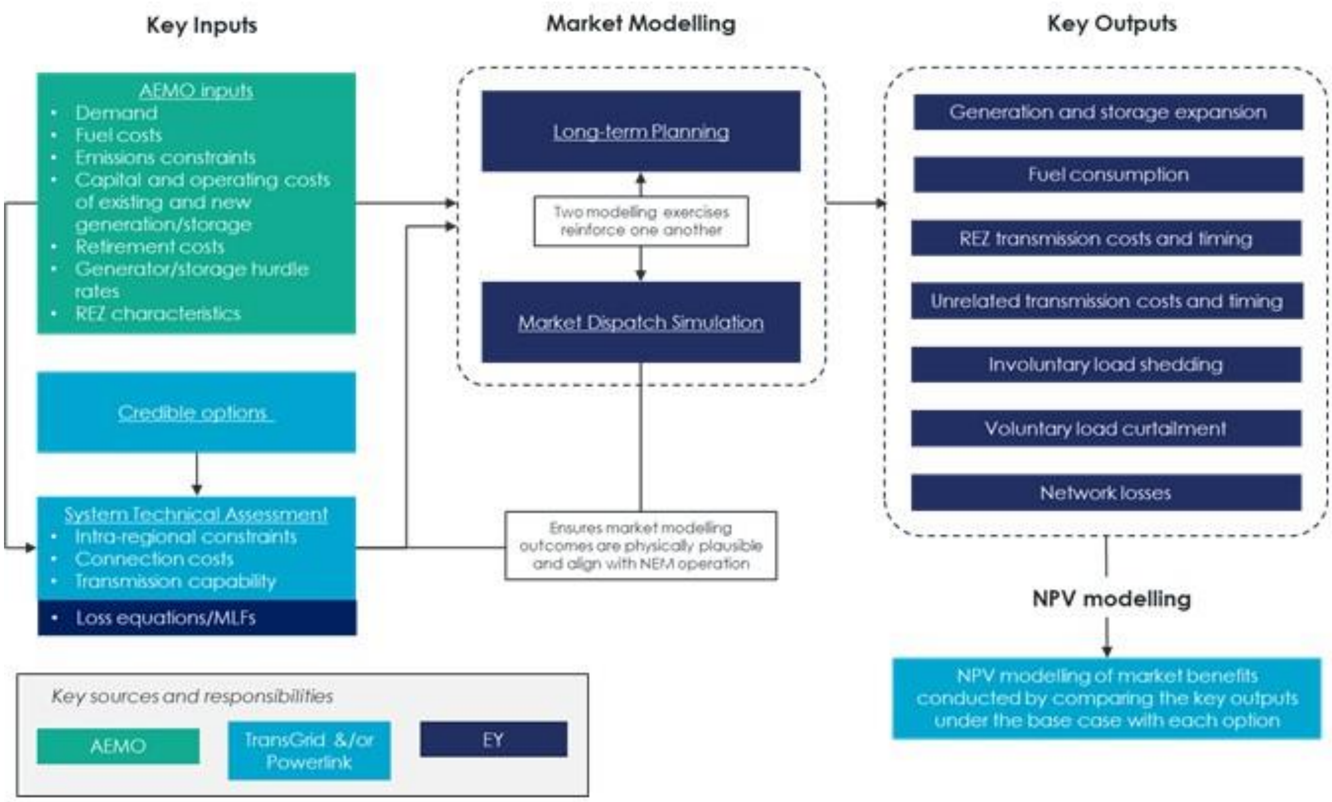
The first solves for the least-cost generation and transmission infrastructure development across the assessment period while meeting energy policies, whereas the second investigates the resulting generation and transmission infrastructure development from a deeper operational perspective. In short, the first creates an optimal investment plan, while the second explores the appropriateness of the investment schedule given the simplifications made in the linear optimisation.

TransGrid and Powerlink have undertaken a detailed System Technical Assessment, which evaluates the power system behaviour and performance under each credible option and ensures market modelling outcomes are physically plausible, follow the operation of the NEM, and that the benefits of credible options are quantified with sufficient accuracy. This assessment serves as an input to the two wholesale market modelling exercises EY has undertaken (as outlined below).

These exercises are consistent with an industry-accepted methodology including within AEMO's ISP.

Figure 21 illustrates the interactions between the key modelling exercises, as well as the primary party responsible for each exercise and/or where the key assumptions have been sourced.

Figure 21 – Overview of the market modelling process and methodologies



As these modelling exercises investigate different aspects of the market simulation process, they necessarily interact and are executed iteratively using inputs and outputs. For example, the Market Dispatch Simulation uses the generation infrastructure development schedule from the Long-term Investment Planning exercise, the detailed network representations from the System Technical Assessment exercise, and other key input assumptions such as those from AEMO.

The two sub-sections below provide additional detail on the two key wholesale market modelling exercises EY has undertaken as part of both the PADR and the PACR assessments. The third sub-section details how intra-regional constraints have been modelled.

The accompanying market modelling report provides additional detail on these modelling exercises, as well as the key modelling assumptions and approach adopted more generally.

Long-term Investment Planning

The Long-term Investment Planning's function is to develop generation (including storage) and unrelated transmission infrastructure forecasts over the assessment period for each of the credible options and base cases.

This exercise determines the least-cost development schedule for each credible option and scenario drawing on assumptions regarding demand, reservoir inflows, generator outages, wind and solar generation profiles, and maintenance over the assessment period.

The generation and transmission infrastructure development schedule resulting from the Long-term Investment Planning are determined such that:

- it economically meets hourly regional and system-wide demand while accounting for network losses;
- it builds sufficient generation capacity to meet demand when economic while considering potential generator forced outages;
- the cost of unserved energy is balanced with the cost of new generation investment to supply any potential shortfall;

- generator's technical specifications such as minimum stable loading, and maximum capacity are observed;
- notional interconnector flows do not breach technical limits and interconnector losses are accounted for;
- hydro storage levels and battery storage state of charge do not breach maximum and minimum values and cyclic losses are accounted for;
- new generation capacity is connected to locations in the network where it is most economical from a whole of system cost;
- NEM-wide and state-wide emissions constraints are adhered to;
- NEM-wide and state-wide renewable energy targets are met, or else penalties are applied;
- generator maintenance outages are scheduled to represent planned generator outages;
- regional reserve requirements are met;
- energy-limited generators such as Tasmanian hydro-electric generators and Snowy Hydro-scheme are scheduled to minimise system costs; and
- the overall system cost spanning the whole outlook period is optimised whilst adhering to constraints.

The Long-term Investment Planning adopts the same commercial discount rates as used in the NPV discounting calculation in the cost benefit analysis. This is consistent with the approach being taken in the 2020 ISP (and was applied in the inaugural 2018 ISP).[82]

Coal-fired and gas-fired generation is treated as dispatchable between its minimum load and its maximum load in the modelling. Coal-fired 'must run' generation is dispatched whenever available at least at its minimum load, while gas-fired CCGT 'must run' plant is dispatched at or above its minimum load. Open cycle gas turbines are typically bid at their short run marginal cost with a zero minimum load level, and started and operated whenever the price is above that level. The accompanying market modelling report provides additional detail on how cycling constraints have been reflected in the analysis.

The Long-term Investment Planning model ensures there is sufficient dispatchable capacity in each region to meet peak demand in the region, plus a reserve level to allow for generation or transmission contingences which can occur at any time, regardless of the present dispatch conditions.

Due to load diversity and sharing of reserve across the NEM, the reserve to be carried is minimised at times of peak and provided from the lowest cost providers of reserve including allowing for each region to contribute to its neighbours reserve requirements through interconnectors.

A question was raised at the February 2019 webinar regarding how generator loss factors have been taken account within the analysis.[83] EY has estimated and applied future loss factors for each unique generation and transmission development schedule in five year increments resulting from the long-term investment planning. These loss factors have been iteratively applied in the long-term investment planning to refine outcomes.[84]

The market modelling report accompanying this PACR provides additional detail on the assumptions and methodological approaches adopted in the Long-term Investment Planning, including necessary model simplifications, sub-regional modelling and how new capacity has been modelled.

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82 AEMO, *Planning and Forecasting 2019 Consultation Process Briefing Webinar*, Wednesday 3 April 2019, slide 21.

83 Stakeholder webinar summary, pp. 3-4.

84 The approach to modelling loss factors is covered in detail as part of the supplementary market modelling and assumptions report released alongside the PADR.

Market Dispatch Simulation

The Market Dispatch Simulation investigates the market and system operation using the resulting generation and transmission development schedule and the detailed network representation from the System Technical Assessment and the Long-term Investment Planning activities.

The model sequentially calculates the least variable cost half-hourly generation dispatch that observes inter-regional and intra-regional network technical and security limitations, where known, over the assessment period. This simulation is executed to validate the operational plausibility of the generation and transmission development schedule from the Long-term Investment Planning activity.

The Market Dispatch Simulation has been applied to obtain an assessment of involuntary load curtailment using Monte Carlo techniques to model the impacts of random forced generator outages.

This modelling evaluates whether simplifications made in the Long-term Investment Planning are valid in a more detailed model, indicating a need for an additional iteration of the Long-term Investment Planning and/or the System Technical Assessment.

Modelling of diversity in peak demand

The market modelling accounts for peak period diversification across regions by basing the overall shape of hourly demand on eight historical years ranging from 2010/11 to 2017/18.

Specifically, the key steps to accounting for this diversification are as follows:

- the historical underlying demand has been calculated as the sum of historical metered demand and the estimated rooftop PV generation based on historical rooftop PV capacity and solar insolation;
- the eight-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region;
- the eight reference years are repeated sequentially throughout the modelling horizon; and
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles and domestic storage) to get a projection of hourly operational demand.

This method ensures the timing of peak demand across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the diversity of timing.

Additional detail on how peak period diversification has been modelled is provided in the market modelling report accompanying this PACR.

Modelling of intra-regional constraints

The wholesale market simulations include models for intra-regional constraints in addition to the inter-regional transfer limits.

Key intra-regional transmission constraints in New South Wales and Queensland have been captured by splitting the regions into zones (two in Queensland, CQ and SQ, and four in New South Wales, NNS, NCEN, CAN and SWNSW), and explicitly modelling intra-regional connectors across boundaries or cut-sets between these zones. Bi-directional flow limits and dynamic loss equations were formulated for each intra-regional connector.

In addition, loss factors for each generator were applied. These were computed from an AC power flow programme interfaced with the Long-term Investment Planning model. The loss factors for each generation investment plan were computed on a five-year basis, and fed back into the Long-term Investment Planning model to capture both the impact on bids and intra-zonal losses.

H3 General modelling parameters adopted

The RIT-T analysis spans a 26-year assessment period from 2019/20 to 2044/45.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life.

A real, pre-tax discount rate of 5.90 per cent has been adopted as the central assumption for the NPV analysis presented in both this PACR and the PADR preceding it. The RIT-T also requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 2.85 per cent,[85] and an upper bound discount rate of 8.95 per cent (i.e., a symmetrical adjustment upwards).

The same commercial discount rates have been adopted for both the NPV discounting calculation in the cost benefit analysis, as well as the generator hurdle rates in the wholesale market modelling, which is consistent with the approach proposed for the 2020 ISP (and which was applied in the inaugural 2018 ISP).[86] This consistency with the 2020 ISP is also in accordance with the anticipated actionable ISP rule changes.

H4 Classes of market benefit not considered material

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.[87]

The PSCR outlined how 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, as well as the reasons why these two categories are not expected to be material. We have not changed our view regarding these potential sources of market benefit, and no parties have commented on these as part of the PSCR consultation.

While the PSCR stated that TransGrid and Powerlink intended 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, we note that this is not relevant to the options considered in the PADR since they do not exhibit flexibility. Consequently, further investigation of ‘option value’ has not been pursued in this PACR. The potential to build flexibility into any of the options to respond to external events occurring (or not occurring) and hence derive ‘option value’ is only relevant for the medium-term upgrades, and so will be considered further as part of the subsequent RIT-T focused on these options.[88] In addition, we have tested as part of the PADR and this PACR only performing discrete components of the preferred option.

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85 This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/electranet-determination-2018-23/final-decision

86 AEMO, *Planning and Forecasting 2019 Consultation Process Briefing Webinar*, Wednesday 3 April 2019, slide 21.

87 NER clause 5.16.1(c)(6).

88 For example, a new line may be able to be built over the medium-term 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).