# Expanding NSW-QLD transmission transfer capacity

## Project Assessment Draft Report

30 September 2019

# Executive summary

TransGrid and Powerlink are investigating network and non-network options for expanding transfer capacity between New South Wales and Queensland necessary to support the long-term interests of consumers for safe, secure, reliable electricity, at the least cost, across a range of plausible futures. This analysis builds on the assessment in the 2018 Integrated System Plan (ISP) prepared by the Australian Energy Market Operator (AEMO).

The 2019 AEMO Electricity Statement of Opportunities (ESOO) has reconfirmed the importance of completing an incremental upgrade to QNI (as well as VNI[1]) ahead of the forecast closure of Liddell Power Station, which it states will improve the supply-demand balance in New South Wales and reduce the likelihood of unserved energy.[2]

We are applying the Regulatory Investment Test for Transmission (RIT-T)[3] 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 Draft Report (PADR) has been prepared as the second formal step in the 'expanding NSW-QLD transmission transfer capacity' RIT-T process and follows the Project Specification Consultation Report (PSCR) released in November 2018.

This PADR focusses on options for increasing transfer capacity between New South Wales and Queensland in the near-term, consistent with the assessment of the 'Group 1' QNI expansion in the 2018 ISP, as well as guidance from the Australian Energy Regulator (AER) provided since the PSCR.[4] This revised focus is to ensure that the consideration of medium-term options (i.e., 'Group 2' QNI expansion in the 2018 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, the timing of which is expected to be informed by the 2020 ISP recommendations.

**Overview**

This PADR confirms the 2018 ISP recommendation that there are significant net benefits associated with expanding transfer capacity between New South Wales and Queensland.

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' at this draft stage of the RIT-T.[5]

The analysis shows that the preferred option is expected to:

- deliver net benefits of approximately $200 million over the assessment period to 2044/45 (in present value terms);
- 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

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

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

3 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.

4 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

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

- generate sufficient benefits to recover the project capital costs two years after the option is commissioned.

## Benefits from expanding transmission transfer capacity between NSW and Queensland

The driver for the investment options considered in this PADR 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 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.

While the summary of these three broad sources of expected benefit have changed in a minor way since the PSCR to reflect the market modelling now undertaken (and presented in this 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'.

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 a reduced need for new gas-fired generation in New South Wales to meet demand once Liddell Power Station retires, as well as benefits from allowing more efficient generation sharing between New South Wales and Queensland. The 2018 ISP conclusions have been reinforced by the assessment in this PADR.

This PADR finds that the net benefit gained by expanding transfer capacity between New South Wales 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 PADR analysis has benefited from extensive stakeholder consultation

Following publication of the PSCR, and an accompanying inputs and methodology consultation paper and assumptions workbook, we held a webinar in early February 2019 to help explain the assessment to stakeholders and to seek stakeholders' views. In December 2018, Powerlink provided its Customer Panel with an overview of the RIT-T and held a focused engagement workshop to receive their input and feedback on the options presented in the PSCR.

Formal submissions from a number of parties were subsequently received, seven of which have been published on our websites[6] (the remainder have requested their submissions be kept confidential).

Prior to, as well as after, receiving submissions, we held a number of bilateral meetings with interested parties in order for them to clarify their submission, provide additional information and understand the RIT-T assessment further. These discussions focussed on the potential for non-network solutions to assist in

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

meeting the identified need and have been pivotal in us being able to define and include two new credible options for assessment in this PADR (outlined below).

We have taken all feedback raised in submissions into account in undertaking our PADR 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).

In July 2019, the AER released a public guidance note[7] outlining the refined focus for this PADR on near-term options for QNI expansion. In addition, TransGrid and Powerlink briefed their respective Customer Panels on this refined focus and presented it to a broad range of stakeholders as part of their Transmission Network and Annual Planning Forums in September 2019.

## Six credible options have been developed and assessed in this PADR

Stakeholder consultation on the PSCR has enabled two new credible options to be defined and assessed as part of this PADR, i.e., in addition to the four incremental credible options to increase transfer capacity identified in the PSCR.

These new options reflect:

- a 'modest' 2 x 40MW/20MWh battery energy storage system (BESS); and
- a refinement of the delivery, costs and capabilities of the original, larger, BESS option proposed in the PSCR (which is now assumed to be a 2 x 200MW/100MWh system).

The table below updates and summarises the six credible options assessed.[8] All credible options are expected to be delivered and inter-network testing completed by June 2022.

**Table E.1 Summary of credible options assessed as part of this PADR**

| 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 | 175 |
| Option 1B – Uprate Liddell to Tamworth lines only | 570 | 1,070 | 34 |
| Option 1C – Install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks | 480 | 1,120 | 142 |
| Option 1D – Sapphire substation cut into line 8C and a mid-point switching station between Dumaresq and Bulli Creek | 480 | 1,110 | 45 |
| *A 'virtual transmission line' comprised of grid-connected battery systems* | | | |
| Option 5A – Small BESS (2 x 40MW/20MWh) | 520 | 1,110 | 110* |
| Option 5B – Large BESS (2 x 200MW/100MWh) | 680 | 1,270 | 461* |

** These are the assumed upfront capital and reinvestment costs for these two options.*

[7] AER, *QNI Regulatory Investment Test*, Guidance Note, July 2019, available at: https://www.aer.gov.au/networks-pipelines/compliance-reporting/guidance-note-queensland-to-new-south-wales-interconnector-regulatory-investment-test

[8] The same option naming/numbering convention has been applied as in the PSCR, i.e., 'Option 1' for the incremental upgrades to the existing network to increase transfer capacity and 'Option 5' for the grid-connected battery systems.

[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 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 has resulted in refining the definition of the QNI transfer capacity.

Option 1A is the 2018 ISP recommended ‘Group 1’ 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 BESS options have been assessed using information (including costs) provided by parties in response to the PSCR and in subsequent engagement with TransGrid and Powerlink. However, in order to maintain confidentiality of commercial-in-confidence information in submissions, the analysis presented in this PADR (including Table E.1) has used public generic storage costs. The use of generic costs does not alter the outcomes of the assessment in terms of which option is preferred overall.

## The preferred option delivers positive net benefits and is the top-ranked option across all reasonable future scenarios

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.

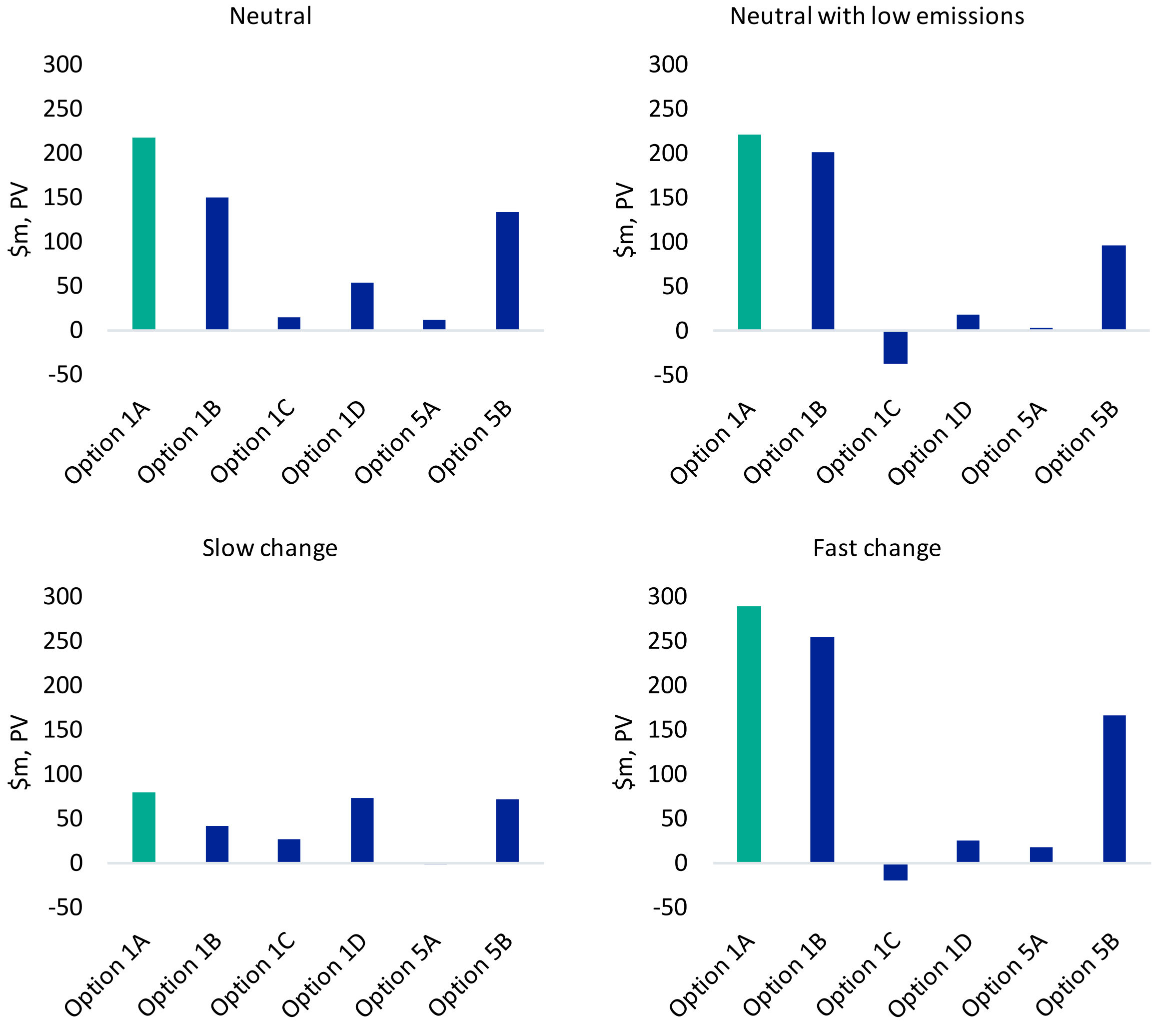
Four scenarios have been considered as part of this PADR, which are intended to cover a wide range of possible futures and are generally aligned with the AEMO proposed 2020 ISP ‘slow change’, ‘neutral’ and ‘fast change’ scenarios. The four scenarios differ in relation to key variables expected to affect 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 PADR assessment find that Option 1A is expected to deliver the greatest net benefits of all options, across all four scenarios considered. Estimated net benefits for this option range from approximately $80 million to $290 million depending on the scenario and, on a weighted basis, it is expected to deliver around 25 per cent more net benefits than the second-ranked option (Option 1B).

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

While Option 5B is the top-ranked BESS option, and has the greatest estimated gross benefit of all options, it is only expected to deliver around 60 per cent of the expected net benefits of Option 1A (on a weighted-basis). This is driven by the relatively high costs associated with Option 5B, 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.

**Figure E.1 – Estimated net benefits for each scenario**




We have also tested the robustness of the assessment to a range of sensitivities, including the deferred assumed retirement of three of Liddell Power Station's units (as recently announced by AGL), the impact of assuming Wood Mackenzie's 'fast' coal price scenario (as part of the latest AEMO ISP assumptions), the effect of including outages during line uprating works, the capital costs of the credible options, and alternate commercial discount rate assumptions. All tests confirm the conclusion that Option 1A is the optimal investment and is a 'no regrets' decision to implement as soon as practicable.

## Next steps and the wider investment approval process

TransGrid and Powerlink welcome written submissions on this PADR. Submissions are due on or before 15 November 2019.

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

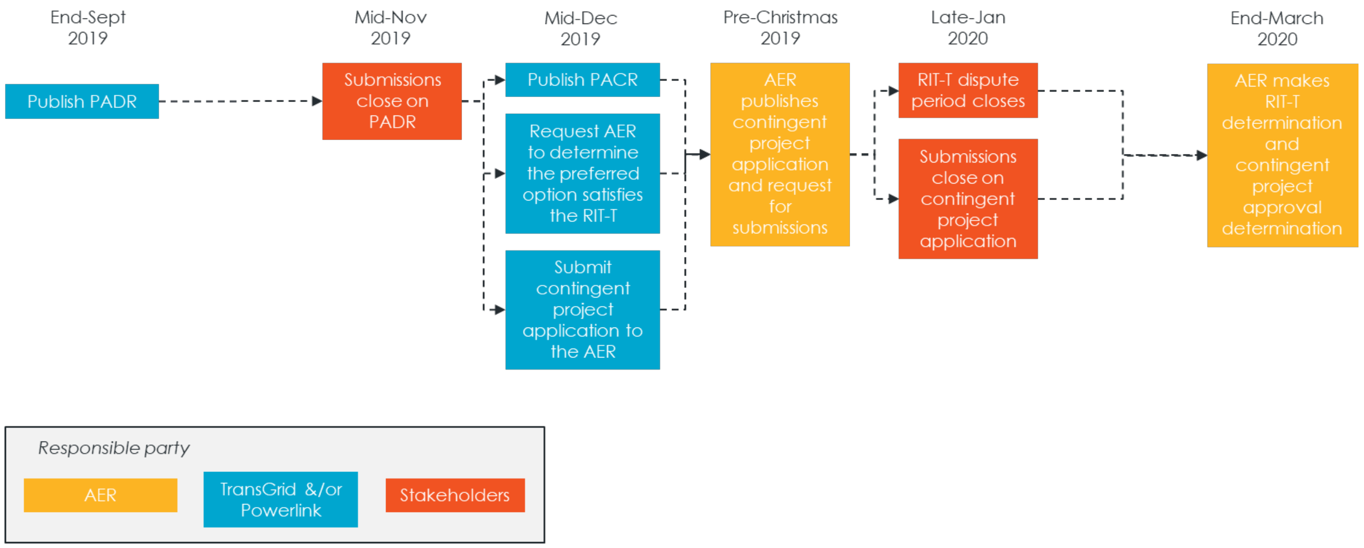
Submissions will be published on the TransGrid and Powerlink websites. If you do not wish for your submission to be made publicly available, please clearly specify this at the time of lodgement.

The next formal stage of this RIT-T is the Project Assessment Conclusions Report (PACR). The PACR will address PADR consultation responses and determine the final preferred option and is expected to be published in December 2019.

Subject to the PACR, TransGrid and/or Powerlink will submit contingent project applications to the AER as part of the wider regulatory investment approval process.

The AER has proposed to adopt an expedited process for considering these contingent project applications. Figure E.2 below summarises this expedited approval process and the expected timeframes.

**Figure E.2 – Expedited investment approval process for this RIT-T**




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

In addition, on 12 November 2018, the New South Wales Government released the NSW Transmission Infrastructure Strategy stating 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 is working with the New South Wales Government on this initiative.

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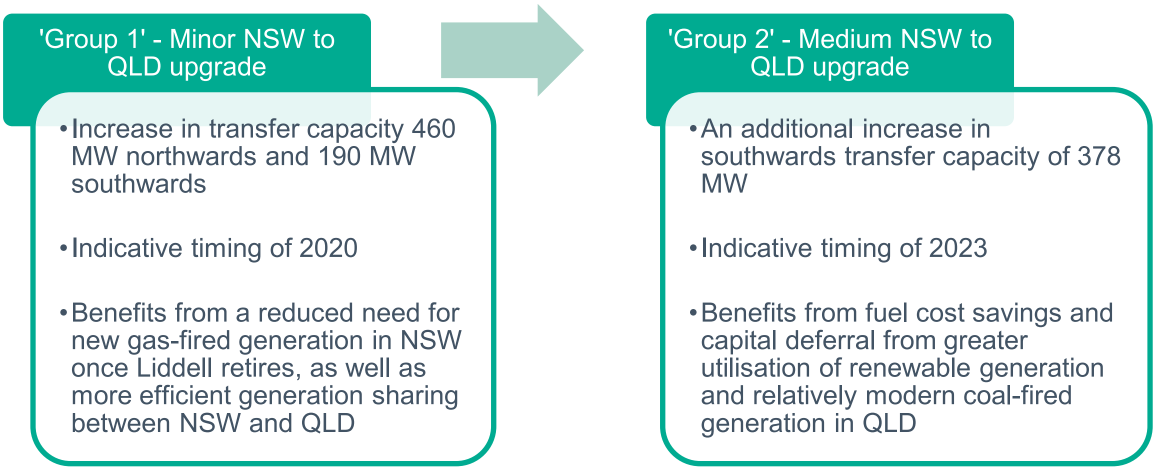
# 1. Introduction

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 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 3.

**Figure 3 – The 2018 AEMO ISP recommended two expansions to NSW-QLD transfer capacity**




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 New South Wales and Queensland.

This Project Assessment Draft Report (PADR) is the second formal step in the RIT-T process and follows the PSCR.

A key development since the PSCR was released is that this PADR has a revised focus on options for increasing transfer capacity between New South Wales and Queensland in the near-term, i.e., before Liddell Power Station is forecast to retire. This is consistent with guidance from the AER following the PSCR.[10]

Three other key developments since the PSCR was released are:

- the addition of two new credible options to address the near-term need being assessed in the analysis following submissions to the PSCR and subsequent discussions with potential proponents;

[10] AER, *QNI Regulatory Investment Test*, Guidance Note, July 2019, available at: https://www.aer.gov.au/networks-pipelines/compliance-reporting/guidance-note-queensland-to-new-south-wales-interconnector-regulatory-investment-test

- the updating of market modelling assumptions so they more closely align with those to be used for the 2020 ISP, which were consulted on by AEMO during early 2019;[11] and
- the recently released 2019 AEMO Electricity Statement of Opportunities (ESOO) reconfirming the importance of completing an incremental upgrade to QNI ahead of the forecast closure of Liddell Power Station.[12]

This report presents the draft findings of the RIT-T assessment, including identifying that the uprating of the Liddell to Tamworth lines and installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks (i.e., Option 1A) is the preferred option, which is expected to maximise overall net benefits. This finding is consistent with the 2018 ISP and confirms the 2018 ISP recommendations that there are expected to be significant benefits with expanding transmission transfer capacity between New South Wales and Queensland in the near-term, ahead of Liddell's forecast retirement.

This RIT-T process is being 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 PADR continues the consultation on options for expanding transmission transfer capacity between New South Wales and Queensland in the near-term. Specifically, it assesses a range of more granular options (including non-network options) than were assessed in the 2018 ISP that would address the 'Group 1' need and presents the cost-benefit analysis of these options.

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 PSCR and the accompanying consultation material (including the webinar held in February 2019), and highlights how these have been addressed in the RIT-T analysis;
3. describes the options being assessed under this RIT-T, including the two additional options developed as part of the PSCR consultation;
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 preferred option at this stage of 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 Group 1 QNI component of the 2018 ISP recommendations. A key purpose of this PADR, and the RIT-T more broadly, is 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 reports on their websites to complement this PADR. Detailed cost benefit results are included as a spreadsheet appendix to this report.

[11] The assumptions applied in this PADR assessment do not align exactly with those proposed for the 2020 ISP (due to these assumptions being only recently released). However, we consider at this stage that they align in all material respects and, as part of the PACR, will be reviewing this and updating assumptions in the analysis where these may be further material.

[12] AEMO, *2019 Electricity Statement of Opportunities*, August 2019, pp.4 & 93.

## 1.2 Submissions and next steps

TransGrid and Powerlink welcome written submissions on this PADR. Submissions are due on or before 15 November 2019.

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

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

The next formal stage of this RIT-T is the Project Assessment Conclusions Report (PACR). The PACR will address PADR consultation responses and determine the final preferred option and is expected to be published in December 2019.

# 2. Key developments since the PSCR

**Summary of key points:**

- This PADR focusses on options for increasing transfer capacity between New South Wales and Queensland in the near-term, ahead of the planned retirement of the Liddell Power Station in NSW, consistent with the 'Group 1' project identified in the 2018 ISP.
- The focus of this PADR on near-term options follows guidance from the AER provided since the PSCR.
  - The medium-term options included in the earlier PSCR will be assessed as part of a separate RIT-T process, the timing of which is expected to be informed by the timing for the medium-term option, identified as part of the 2020 ISP recommendations.
- The intention of separating the assessment of the near-term options from medium-term options is to ensure that the consideration of medium-term options does not delay the consideration and progression of near-term options, which will provide net economic benefits to NEM participants, particularly in light of the forecast closure of Liddell Power Station over 2022 and 2023.
- Two new credible options for near-term investment have been developed and assessed following submissions to the PSCR, and have been assessed alongside the four incremental options identified in the PSCR.
- The market modelling assumptions have been updated to align more closely with those to be used for the 2020 ISP, which were consulted on by AEMO during early 2019.
- The recently released 2019 AEMO ESOO has reconfirmed the importance of completing an incremental upgrade to QNI ahead of the forecast closure of Liddell Power Station to reduce the likelihood of unserved energy.
- AGL has recently announced that it plans to defer the retirement of three of Liddell's four units until 2023, which does not change the identified preferred option in this PADR. The recent AGL announcement provides additional assurance that the preferred upgrade option will be commissioned in advance of the Liddell Power Station being completely retired.
- The AER has committed to expediting the wider investment approval process since the PSCR, consistent with the ESB's 'actionable ISP'.

## 2.1 Refined RIT-T focus on near-term options (including the 2018 ISP 'Group 1' option)

The inaugural Integrated System Plan (ISP), released by the Australian Energy Market Operator (AEMO) in July 2018, recommended two key transmission investments in relation to expanding transfer capacity between New South Wales and Queensland. AEMO differentiated these two investments as being needed over:

- the near-term (by around 2020, or as soon as they could be delivered) – the 'Group 1' recommended investment; and
- the medium-term (by the mid-2020s) – the 'Group 2' recommended investment.

AEMO stated that the need for the Group 1 recommended investment arises from the benefits of avoiding new gas-fired generation in New South Wales, which would otherwise be needed to meet demand once Liddell is forecast to retire, as well as benefits from allowing more efficient generation sharing between New South Wales and Queensland (particularly in light of the Queensland Renewable Target (QRET)).[13]

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

While the PSCR for this RIT-T identified a range of options for delivering increases in transfer capacity between the two states, including the 2018 ISP recommended Group 1 and Group 2 investments, this PADR (and the PACR that will follow it) focusses on the economic benefits to be gained from the near-term options that can be put in-place prior to the forecast retirement of Liddell Power Station.

This revised focus follows guidance from the AER regarding scope of this RIT-T. The intention of the revised focus is to ensure that the consideration of medium-term options does not delay the implementation of the optimal near-term option (and the associated expected economic benefits that will flow to NEM participants).

In July 2019, the AER released a public guidance note[14] outlining the refined focus for this PADR. TransGrid and Powerlink briefed their respective Customer Panels on this refined focus and presented on it as part of their Transmission Network and Annual Planning Forums in September 2019.

The medium-term options that were discussed in the PSCR (including the 'Group 2' 2018 ISP recommended option) will be assessed as part of a separate RIT-T in the future, the timing of which is expected to be informed by the timing of the medium-term option identified as part of the 2020 ISP recommendations.

## 2.2 AEMO's 2019 ESOO has reconfirmed the benefits of upgrading QNI in the near-term

The 2019 AEMO Electricity Statement of Opportunities (ESOO) has forecast that the level of unserved energy in New South Wales will increase following the forecast closure of Liddell Power Station if action is not taken. The 2019 ESOO forecasts that a combination of high summer demand and unplanned generator outages will leave New South Wales exposed to significant supply gaps and involuntary load shedding if no mitigation action is taken (in 2023-24, AEMO forecasts a risk to between 135,000 and 770,000 households in New South Wales being without power for three hours during an extreme heat event).[15]

The 2019 AEMO Electricity Statement of Opportunities (ESOO) has also reconfirmed the importance of completing an incremental upgrade to QNI (as well as VNI[16]) ahead of the forecast closure of Liddell Power Station, which it states will improve the supply-demand balance in New South Wales and reduce the likelihood of unserved energy.[17]

## 2.3 Two new near-term options have been developed following consultation

Stakeholder consultation on the PSCR has enabled two new credible options to address the near-term need to be defined and assessed as part of this PADR.

These two new options reflect:

- a 'modest' 2 x 40MW/20MWh battery energy storage system (BESS); and
- a refinement of the delivery, costs and capabilities of the original, larger, BESS option proposed in the PSCR (which is now assumed to be a 2 x 200MW/100MWh system).

Each of these new credible options has been considered alongside the four near-term credible options to increase transfer capacity identified in the PSCR.

The BESS options have been assessed using information (including costs) provided by parties in response to the PSCR and in subsequent engagement with TransGrid and Powerlink. However, in order to maintain confidentiality of commercial-in-confidence information in submissions, the analysis presented in this PADR

[14] AER, *QNI Regulatory Investment Test*, Guidance Note, July 2019, available at: https://www.aer.gov.au/networks-pipelines/compliance-reporting/guidance-note-queensland-to-new-south-wales-interconnector-regulatory-investment-test

[15] AEMO, *2019 Electricity Statement of Opportunities*, August 2019, p. 4.

[16] 'VNI' is the proposed increase in transmission transfer capacity between Victoria and New South Wales.

[17] AEMO, *2019 Electricity Statement of Opportunities*, August 2019, pp.4 & 93.

has used public generic battery storage costs. The use of generic costs does not alter the outcomes of the assessment in terms of which option is preferred.

## 2.4 Market modelling assumptions and approaches have been updated to better align with those to be used for the 2020 ISP

The market modelling assumptions and approaches have been updated since the PSCR to better align with those to be used for the 2020 ISP, which were consulted on by AEMO during early 2019. In particular, these updated parameters include changes to:

- Renewable Energy Zone build limits;
- generation technology cost projections;
- newly committed generation; and
- coal and gas fuel cost projections.

The market modelling in this PADR includes some deviations from the AEMO ISP planning and forecasting assumptions from early 2019, based on the latest information available at the time the modelling assumptions for this PADR were finalised. We will consider the impact of any material changes in assumptions since that time in the PACR.

The slow change scenario has been amended since the PSCR, and now excludes both the Victoria to NSW interconnector (VNI) upgrade and developments related to Snowy 2.0 (i.e., Snowy 2.0 generation, HumeLink and KerangLink). This approach has been taken to recognise that HumeLink and KerangLink are not committed at this stage, and extends the slow change scenario to be a more robust test of the net economic benefits that might be expected from the credible options considered.

## 2.5 Announced deferred retirement of three of Liddell's units

AGL announced on 2 August 2019 that it plans to defer the retirement of three of Liddell's four units until April 2023 (the one other unit is still scheduled to retire in April 2022).[18]

While the core modelling scenarios in this PADR assume that Liddell Power Station retires completely in 2022, consistent with expectations at the time the PADR modelling assumptions were finalised, a sensitivity has been included that investigates the effects of this deferred staged retirement. This sensitivity is presented in section 8.6.1 and finds that, while the estimated net market benefits of all options reduce marginally due to this deferred retirement, it does not alter the outcome of the analysis or conclusions regarding the preferred option.

Moreover, the deferred retirement assists with the deliverability of the preferred option and provides assurance that the increased capacity can be made available in advance of Liddell Power Station being completely retired.

## 2.6 The wider investment approval process will be expedited

While the RIT-T is an important component of the wider investment approval process TransGrid and Powerlink are required to undertake for network transmission investments, another key component is the contingent project approval process. The current AER revenue determinations for TransGrid and Powerlink both require that, following completion of this RIT-T, the AER must make a determination as to whether the preferred option satisfies the RIT-T in order to subsequently trigger a 'contingent project'.[19]

Consistent with the guidance regarding expediting a near-term expansion of transfer capacity between New South Wales and Queensland, the AER has proposed to adopt an expedited process for considering whether

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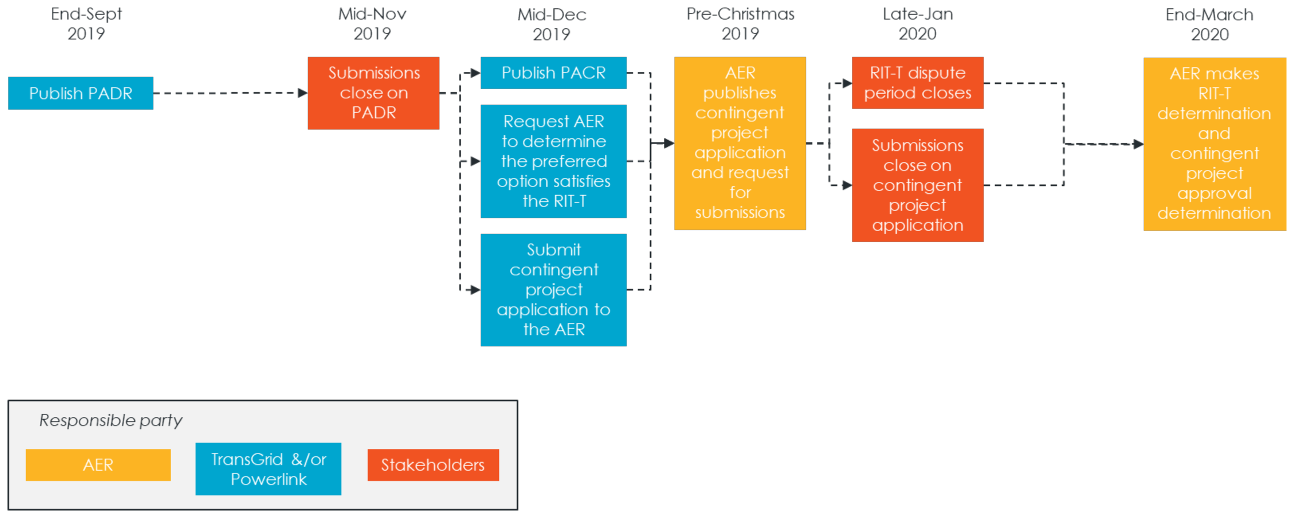
[18] https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2019/august/schedule-for-the-closure-of-agl-plants-in-nsw-and-sa

[19] AER, *Final Decision TransGrid transmission determination 2018 to 2023*, Attachment 6 – Capital expenditure, May 2018, p. 143; and AER, Final Decision, *Powerlink transmission determination 2017−22*, Attachment 6 – Capital expenditure, April 2017, p. 43.

the ultimately preferred near-term option satisfies the RIT-T as part of the contingent project approval process. This expedited approval process is depicted in Figure 4, along with the remainder of the RIT-T process.

**Figure 4 – Expedited investment approval process for this RIT-T**




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

A number of briefing sessions with the AER have been held throughout the preparation of this PADR (and are planned to be held for the PACR) in order to assist the AER in making its contingent project determination on this expedited timeframe. These briefing sessions focused on the market modelling of the expected benefits from each option and, overall, testing the robustness of the preferred option identified.

We note that an expedited AER determination as to whether the ultimately preferred option satisfies the RIT-T does not take away from the timeframes and consultation the AER is required to undertake on the contingent process application. These are stipulated under NER section 6A.8.

While the actionable ISP model has been further developed by the ESB since the PSCR, but is still not reflected in the NER, TransGrid and Powerlink consider these commitments consistent with this model.

# 3. 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 PADR is to deliver a net economic benefit to consumers and producers of electricity and support energy market transition through:[20]
  - 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.
- 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 New South Wales to meet demand once Liddell retires, as well as benefits from allowing more efficient generation sharing between New South Wales and Queensland.[21]
- The net benefits from the medium-term upgrade options (e.g., the 2018 ISP recommended 'Group 2' investment) are expected to add to these net benefits, and will be assessed as part of a subsequent RIT-T process.

## 3.1 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 New South Wales and Queensland in the near-term would provide benefits in terms of the reduced need for new gas-fired generation in New South Wales to meet demand once Liddell retires.[22]

Each of the credible options assessed as part of this PADR expand the transfer capacity between New South Wales and Queensland and allow the supply-demand balance in New South Wales to continue to be met but at a lower cost than if new generation and/or storage capacity was to be constructed in New South Wales following the forecast retirement of Liddell Power Station (and other thermal plants further in the future).

The market modelling undertaken as part of this PADR finds that the preferred option enables significant investment in new capacity to be avoided or deferred in New South Wales – with the mix of the technologies

[20] 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 this 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'.

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

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

avoided depending on the specific scenario modelled including OCGT or new renewable technologies (primarily solar, wind, pumped hydro and large-scale storage).

## 3.2 Benefits from more efficient sharing of generation

The 2018 ISP also concluded that an upgrade to the transmission transfer capacity between New South Wales and Queensland in the near-term would provide benefits in terms allowing for more efficient generation sharing between New South Wales and Queensland going forward.[23]

More efficient generation sharing from increasing transfer capacity between Queensland and New South Wales arises as a result of geographical weather diversity resulting 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 the case 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 New South Wales, 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 low 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.[24]

The market modelling 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 New South Wales 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.

## 3.3 Benefits attributable to the transition to lower carbon emissions

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

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

As part of the 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).

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 will continue to consider how to best develop REZs in future so that their development is optimised together with

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

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

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

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

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, 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.[27]

Within the context of the RIT-T assessment, greater interconnection between NSW and Queensland that facilitates the transmission to lower carbon emissions 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 inferior 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.

## 3.4 Medium-term 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.[28]

Whether this RIT-T would cover both sets of options was raised during both the February 2019 webinar[29] and the Powerlink Customer Panel briefing.[30] While the response at the time was that the expected outcome of this RIT-T was expected to 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 (as outlined in section 2.1 above) has necessitated the consideration of these medium-term options as part of a subsequent RIT-T process.

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

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

29 Stakeholder webinar summary, p 1.

30 Powerlink Customer Panel briefing summary, p 1.

# 4. Consultation on the PSCR has been incorporated in this analysis

**Summary of key points:**

- We have undertaken extensive stakeholder consultation to investigate the potential credible options for expanding transfer capacity between New South Wales and Queensland in the near-term and ensure the robustness of the RIT-T findings
- This consultation has included a webinar on the PSCR, publication of a separate detailed market modelling and assumptions report, briefing our Customer Panels, bilateral discussions with interested stakeholders, and the release of detailed analysis in response to stakeholder requests.
- The options and analysis presented in this PADR have consequently been shaped by this consultation, which has helped test the conclusions reached and ensure the robustness of the analysis.
- We have 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 and encourage parties to continue to engage with us over the course of this RIT-T.

TransGrid and Powerlink published the PSCR in November 2018 and an accompanying input and methodology consultation paper and assumptions workbook in December 2018. The December 2018 documents provided additional detail on the proposed economic and wholesale market modelling to be undertaken, as well as further information on the specification of the credible options assessed.

In December 2018, Powerlink provided its Customer Panel with an overview of the RIT-T and held a focused engagement workshop to receive their input and feedback on the options presented in the PSCR. The panel sought responses to specific questions on the RIT-T and, subsequently, Powerlink made this information publicly available to all stakeholders on its website.[31]

A webinar was held by TransGrid and Powerlink in early February 2019 to provide further information on the drivers for this RIT-T, the options being considered and to seek input and feedback from stakeholders. A summary of the questions raised, along with our answers, was subsequently published on the TransGrid and Powerlink websites.[32]

Formal submissions from a number of parties were subsequently received, seven of which have been published on our websites[33] (the remainder have requested their submissions be kept confidential). While submissions covered a range of topics, there were six broad topics that were most commented on, namely:

- the potential for grid-connected battery systems to address the near-term need;
- potential non-network options;
- additional variants for near-term network options;

31 https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity

32 https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity/Documents/Expanding%20NSW%20-%20Queensland%20Transmission%20Transfer%20Capacity%20-%20Stakeholder%20Webinar%20QandA.pdf & https://www.powerlink.com.au/expanding-nsw-qld-transmission-transfer-capacity

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

- additional options for increasing transfer capacity in the medium-term (i.e., in-line with the scope and timing of the 2018 ISP 'Group 2' recommended investment);
- alignment with the latest ISP and ESOO assumptions; and
- other modelling assumptions.

In addition, prior to, as well as after, receiving submissions, we held a number of bilateral meetings with interested parties in order for them to further understand the RIT-T assessment. Many of these discussions focussed on the potential for non-network solutions to assist in meeting the identified need in the near-term. In total, TransGrid and Powerlink have held more than 15 such meetings with stakeholders to-date, which have played a pivotal role in being able to define and include two new credible options for assessment in this PADR.

We have published the submissions received, excluding those that requested to be kept confidential, on both the TransGrid and Powerlink websites.[34]

The key matters raised in submissions relevant to the RIT-T assessment are summarised in the following subsections, as well as the TransGrid and Powerlink responses and how the matters raised have been reflected in the PADR assessment. Appendix C provides a summary of all points raised as part of consultation on the PSCR.

## 4.1 A ‘virtual transmission line’ comprised of grid-connected battery systems

Submissions from stakeholders and further engagement since the PSCR have identified a number of potential battery solutions with the potential to address the near-term need. This has enabled two BESS credible options to be assessed as part of the PADR, as outlined below.

The two BESS options have been assessed using material (including costs) provided by parties in response to the PSCR and in subsequent engagement with TransGrid and Powerlink. However, in order to maintain confidentiality of commercial-in-confidence information in submissions, the analysis presented in this PADR has used public, generic storage costs. The use of generic costs has not altered the outcomes of the assessment in terms of which option is preferred.

### 4.1.1 A new ‘modest’ BESS

Three parties suggested that a smaller BESS than that proposed in the PSCR may add incremental net benefits and could be coupled with a network investment. Two of these parties provided details on the suggested size of such a BESS, which was 40MW in both cases.

TransGrid and Powerlink have met with each of these parties to understand each of their proposals further, which has enabled a new credible option to be defined and assessed as part of this PADR (Option 5A).

Section 5.2.1 summarises this new option, while section 7 summarises its cost-benefit assessment.

### 4.1.2 Rescoped larger BESS

Three parties commented on the more substantial BESS option proposed in the PSCR, including that the:

- BESS can be staged to allow for greater increases in transfer capacity in the near-term;

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

- initial stage should involve 200MW capacity installations at either end and that this can be installed within 12 months; and
- costs in the PSCR could be reduced, particularly if the BESS provider participates in the energy and/or FCAS markets with the non-reserved capacity of the battery.

One of these parties, Gaia RE, who are currently developing a solar farm in Bonshaw New South Wales (that is proposed to connect to the Dumaresq substation), suggested that this development, along with battery storage, can provide SIPS, FCAS and load shifting services.[35] Consultation with other submitters also raised the prospect of the cost of these options being able to be reduced if an owner, or operator, is permitted to participate in the energy and/or FCAS markets with the non-reserved capacity of the battery.

We consider that the full power capacity of the BESS proposed needs to be firm and reserved for managing the QNI stability limits, and so we do not consider this to be commercially feasible at this stage. Specifically, to provide the modelled limit improvements, the full quoted MW and MWh needs not to be used pre-contingent and fully available for post-contingent use. In addition, we note some of the BESS proposals received involved third-party ownership and would be provided on an opex-basis, which could have implicitly included the netting off of these other revenue streams.

While the two BESS options presented in this PADR assume generic placeholder network-owned batteries, we have also modelled these options using the costs and ownership structures proposed by proponents (i.e., both network-owned and third-party-owned) and do not find these to change the overall finding of the assessment in terms of the preferred option. These assessments have not been presented in the PADR for confidentiality reasons.

Overall, consultation with these parties has enabled the initially proposed BESS option in the PSCR to be further refined. Section 5.2.2 summarises how this option now involves a smaller 2 x 200MW/100MWh BESS, while section 7 summarises the cost-benefit assessment of this option.

In discussions with one party, it was raised whether a braking resistor, instead of a second battery, could further reduce the costs but noted that this may come at the expense of lower market benefits since it would only extend southerly limits. The use of a braking resistor is not considered technically feasible since braking resistors of these size typically only operate for seconds and the action is required to be sustained for many minutes.

## 4.2 Non-network options

In addition to the two network support BESS offers outlined above, we also received a submission suggesting that a new renewable project could provide services that contribute to meeting the identified need. While TransGrid and Powerlink have discussed this option with the submitter, they made a decision in early August 2019 to withdraw their offer.

The question of how any non-network solution would be paid for was raised as part of the February 2019 webinar.[36]

Where a non-network solution emerges as the preferred option (or part of it), and is provided by a third-party, it would be paid for directly by TransGrid and/or Powerlink (depending on its location), with those costs then forming part of the regulated network operating costs paid for by consumers as part of their transmission charges. More specifically, TransGrid and/or Powerlink would recover the cost of non-network solutions in its transmission charges through the grid support pass through mechanism in the NER.

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35 GAIA submission, p 1.

36 Stakeholder webinar summary, pp 3-4.

## 4.3 Variants of the network options proposed in the PSCR

Walcha Energy suggested that Option 1A should include uprating of 330kV lines between Tamworth and Armidale.[37] TransGrid and Powerlink do not consider there is a current driver to address any congestion on these lines, primarily due to a lack of committed generation developments at this point in time (but have allowed for this congestion to occur in the market modelling). Further, we note that neither the costs nor benefits of relieving any congestion on this transmission route (i.e., deeper in the New South Wales network) have been included in the assessment and would be subject to a separate RIT-T process.

Walcha Energy also stated that:

- Option 1B and Option 1C in the PSCR do not adequately meet the identified need, even as an interim step – it was suggested that the works are necessary but only part of an equally essential larger package, and thus this option underestimates scope and costs;[38] and
- a cut in of Sapphire to circuit 8C is essential for Option 1D in the PSCR and thus may be able to be pursued separately – it added that, in the case that it is a low-cost item, the cut in may be done without necessitating a RIT-T.[39]

While Option 1B and Option 1C involve lower costs and smaller increases in transfer capacity than Option 1A, they have been developed based on additional studies and consultation undertaken since the 2018 ISP (which recommended Option 1A in the immediate term). Specifically, they reflect alternate lower cost options which target different types of power transfer limitations between the states in the near-term and have been included to investigate whether these options are able to provide similar levels of estimated *net* benefit to Option 1A.

While the cut-in of Sapphire to circuit 8C is one component of Option 1D, it cannot be separated and undertaken without a RIT-T. Specifically, these costs are unique to Option 1D and are required to be assessed, along with the other components of this option, against the other credible options to meet the identified need for this RIT-T. Moreover, we note that the capital cost of these cut-in works is approximately $20-25 million, which is in excess of the current $6 million RIT-T threshold.

### 4.3.1 The use of series compensation

Smart Wires, a provider of modular power flow control solutions (including modular static synchronous series compensation), highlighted the omission of series compensation in any of the options. This point was further discussed in the QNI PSCR webinar in early February 2019.[40] Smart Wires suggested an alternative option employing modular series compensation devices to increase the transfer limits on QNI.[41]

Series capacitors were considered in the 2012-2014 RIT-T undertaken for QNI expansion but were not progressed beyond the PADR due to their potential sub-synchronous resonance interactions with nearby generators. For this reason, options involving series compensation were considered not to be technically feasible options for this RIT-T assessment at the PSCR stage. However, as raised in consultation, we are aware of technologies that can now provide series compensation without causing sub-synchronous resonance, which has the potential to alleviate these technical issues.

In order to further understand the credibility of a series compensation option, TransGrid and Powerlink have:

- met with Smart Wires to further understand the technical parameters of a series compensation option, lead times and costs;
- undertaken additional technical analysis to scope a potential option; and

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[37] WalchaEnergy submission, p 12.

[38] WalchaEnergy submission, p 12.

[39] WalchaEnergy submission, p 12.

[40] Stakeholder webinar summary, p 2.

[41] Smart Wires submission, pp 1-4.

- commissioned an independent consultant (Manitoba Hydro International) to technically assess this option.

These activities together have led TransGrid and Powerlink to consider the use of series compensation to not be a suitable option at this time. Although the technology has been used to control the impedance of transmission lines, which improves sharing over parallel lines, they have not yet been deployed for applications that increase stability limits. The timeframes for this PADR necessitate the use of technologies that have already demonstrated this capability. Section 5.3 provides additional detail on why the use of series compensation has not been progressed as a credible option in this initial RIT-T which focuses on the near-term.

## 4.4 Comments on medium-term options for increasing transfer capacity

A number of parties commented on the options for increasing transfer capacity in the longer-term between New South Wales and Queensland. Points raised captured a range of topics, including:

- acquisition of easements for these options;
- their respective interactions with the development of large renewables (i.e., REZ developments);
- any benefits of 'controllability' and the management of system stability;
- the interaction with the existing HVDC interconnector between New South Wales and Queensland (Directlink); and
- the capability of a BESS option over the medium-term.

As outlined in section 2, this PADR has been progressed to focus on the immediate options for expanding transfer capacity between New South Wales and Queensland, i.e., those that can be commissioned prior to Liddell's expected retirement date. Medium-term options for expanding transfer capacity will be subject to a separate RIT-T process. TransGrid and Powerlink will take into account the points made in submissions as part of this subsequent process.

## 4.5 Alignment with the latest ISP and ESOO assumptions

ERM Power stated concern that the modelling would rely on AEMO's forecasting in the ESOO 2018, which it considers may overstate demand.[42] EnergyAustralia shared this view, highlighting that the underpinning modelling assumptions of the 2018 ISP are now dated and that the latest ISP/ESOO assumptions should be used.[43]

The assumptions and approaches used in this PADR assessment of net benefits are based on the planning and forecasting assumptions that have been consulted on by AEMO in the context of the 2020 ISP. Where updated assumptions were not available from AEMO by the latest time modelling 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. Where additional information is now available (or becomes available) and has not been reflected in this PADR (e.g., the 2019 ESOO demand forecasts), we will consider the materiality of the change in assumptions as part of the PACR assessment.

## 4.6 Comments on other modelling assumptions and approaches

UPC Renewables submitted that overinvestment may result from failure to properly account for future requirements for firming generation in both New South Wales and Queensland.[44]

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42 ERM Power Limited submission, p 2.

43 EnergyAustralia submission, p 2.

44 UPC Renewables submission, pp 1-2.

The market modelling undertaken for this PADR adopts the same approach to firming and system strength as AEMO took in the 2018 ISP and is proposing to take in the 2020 ISP. While the system strength requirements have been taken into account in characterising each option, we note that there is not expected to be a material difference across the options assessed in this PADR.

EnergyAustralia noted that the market modelling should consider the economic viability of all existing power stations.[45] While we have not explicitly modelled the economic viability of existing power plants, and have instead assumed existing generator retirement dates based on their standard technical lives,[46] we note that the four scenarios modelled have a range of assumed generator retirement dates (and, as set out in section 8, all find the same option is preferred). Explicitly modelling the economic viability of power stations would require a significant modelling and data gathering exercise that would not be considered proportionate, given the variability inherent within the current scenarios and revised focus of the PADR assessment.

EnergyAustralia suggested that TransGrid and Powerlink consider variations in whether other ISP transmission investments proceed, rather than just changes in timing.[47] We have included these coincident transmission developments in each of the scenarios consistent with the ESB's 'actionable ISP' proposal. The one exception to this is the slow-change scenario, which has been amended since the PSCR and now excludes both the Victoria to NSW interconnector upgrade and the Snowy developments to recognise their earlier stage in the development process, and to be an even more robust test of the net market benefits that might be expected from the various credible options considered.

EnergyAustralia submitted that the option analysis which is performed as part of the PADR should include market impacts of transmission outages that are required to complete the works.[48] Material transmission outages only apply to the line uprating options (Option 1A and Option 1B) as they require line outages for a number of weeks while the work is performed. We have considered the effects of these outages within the market modelling of these options by way of a sensitivity (see section 8.6).

EnergyAustralia submitted that the discount rate of 4.6 per cent should be increased to a higher rate, given the risk customers/consumers are being asked to bear.[49] The 4.6 per cent rate referenced in the PSCR is the lower bound sensitivity rate that was proposed to be investigated at that time based on the latest AER final decision on the regulated weighted average cost of capital (WACC).[50] As outlined in section 7.3, we have adopted a real, pre-tax discount rate of 5.90 per cent as the central assumption for the NPV analysis presented in this PADR, as reflecting a current 'commercial' discount rate consistent with the RIT-T requirements. The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated 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,[51] and an upper bound discount rate of 8.95 per cent (i.e., a symmetrical adjustment upwards).

EnergyAustralia commended the transparency provided in the PSCR and urged similar transparency around the modelling results presented in the PADR.[52] This PADR, and the accompanying information, builds on the level of information already provided as part of this RIT-T assessment and allows interested parties to review

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45 EnergyAustralia submission, p 2.

46 AEMO, *Scenarios, Inputs, Assumptions, Methodology, Timeline, and Consultation Process*, 2019 Planning and Forecasting Consultation Paper, February 2019, p 39.

47 EnergyAustralia submission, p 2.

48 EnergyAustralia submission, p 4.

49 EnergyAustralia submission, p 2.

50 This is consistent with the RIT-T. The 4.6 per cent rate in the PSCR came from the latest AER final decision for a TNSP at that point in time.

51 This is equal to the 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/tasnetworks-determination-2019-24

52 EnergyAustralia submission, p 3.

the net benefits estimated for, and factors driving, each option. All material is available to be downloaded from the TransGrid and Powerlink websites or by contacting regulatory.consultation@transgrid.com.au.

ERM Power stated that an independent verification of potential transfer capability and limit factors should be contained as an appendix to the PADR.[53] Minor queries regarding the transfer capabilities were also raised as part of both the December 2018 briefing of Powerlink's Customer Panel and the webinar in February 2019.[54]

The transmission transfer capacities for each of the options are not static, and fluctuate depending on the particular operating state of the network at the time. In the body of this PADR (i.e., Table 3), transfer capacities are presented using network operation aligned with daytime, medium demand conditions. Appendix D provides additional detail on the modelled transfer capacities of the options, across a wider range of operating states.

Changes in transfer capacities have been modelled by TransGrid and Powerlink in accordance with industry best practices and in line with our respective roles as jurisdictional transmission planners. An independent verification of the transmission transfer capacities is not considered to be required. The expected range of transfer capabilities for each option over a range of conditions has been provided alongside this PADR.

Participants in the February 2019 webinar requested more information on how the market benefit analysis takes into account loss factors.[55] As outlined in section 7.2.1, the market modelling undertaken as part of this PADR assessment 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.[56]

## 4.7 Other points raised

UPC Renewables submitted concerns regarding potential political uncertainty and its influence on any analysis made.[57]

Investigating the robustness of the credible options to uncertainty regarding the future is a key feature of the RIT-T, and is captured through the use of a range of reasonable scenarios and sensitivity tests. The scenarios and sensitivities investigated as part of this PADR are discussed in sections 6.1 and 6.3, 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.

EnergyAustralia submitted that the PADR should discuss the impact of any increases in inter-state transfer capacity on hedging markets.[58] Expanded transfer capacity between New South Wales and Queensland is expected to improve the ability of parties to obtain hedging contracts in both states due to the increased interlinkage (and consequent increase in firm interconnection between the states). While the market modelling undertaken in this PADR does not take into account impacts on the contract market directly, since it would involve a substantial amount of modelling resources and time and is not expected to affect the overall outcome of the assessment, it does capture changes in the costs of dispatching generation in the NEM, which are ultimately passed on as savings to consumers.

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53 ERM Power Limited submission, p 1.

54 Powerlink Customer Panel briefing summary, p. 1; and stakeholder webinar summary, p 4.

55 Stakeholder webinar summary, pp 3-4.

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

57 UPC Renewables submission, pp 2-3.

58 EnergyAustralia submission, p 3.

It was raised at the February 2019 webinar whether costs and benefits would be estimated separately for New South Wales and Queensland.[59] Similarly, members of Powerlink's Customer Panel requested a breakdown of costs for each option showing what proportion is paid for by customers in each of the two states.[60]

In terms of benefits, we note that the RIT-T is required to look at market benefits across the NEM as a whole to find the optimal solution without assessing regional impacts. Notwithstanding, these regional impacts are discussed in section 8 as well as in the accompanying wholesale market modelling report.

The table below provides an estimate of how the costs of each option are expected to be split between New South Wales and Queensland.

**Table 2 Indicative proportion of option capital costs between NSW and Queensland**

| Option description | Estimated capex ($m) | NSW works | QLD works |
|---|---|---|---|
| *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 | 175 | 100% | - |
| Option 1B – Uprate Liddell to Tamworth lines only | 34 | 100% | - |
| Option 1C – Install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks | 142 | 100% | - |
| Option 1D – Sapphire substation cut into line 8C and a mid-point switching station between Dumaresq and Bulli Creek | 45 | 55% | 45% |
| *A 'virtual transmission line' comprised of grid-connected battery systems* | | | |
| Option 5A – Small BESS (2 x 40MW/20MWh) | 110* | 50% | 50% |
| Option 5B – Large BESS (2 x 200MW/100MWh) | 461* | 50% | 50% |

** These are the assumed upfront capital and reinvestment costs for these two options.*

Under the NER, where transmission assets in one region are used to supply customers in another region, part of the cost of those assets are charged to customers in the importing region through an 'inter-regional TUOS' or 'IR-TUOS' charge. The ultimate apportioning of costs between the two states is therefore not solely determined by the quantum of investment in each jurisdiction. Projecting future IR-TUOS amounts is highly uncertain and has not been undertaken as part of this PADR. We also note that the approach to IR-TUOS is being considered as part of the AEMC's current 2019 COGATI Review.[61]

59 Stakeholder webinar summary, pp 1-2.

60 Powerlink Customer Panel briefing summary, p. 1.

61 https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

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

**Summary of key points:**

- This PADR considers six credible options for increasing transfer capacity between New South Wales and Queensland in the near-term, reflecting a range of technologies, costs and capabilities.
- Stakeholder consultation on the PSCR has enabled two new credible options to be included in this PADR, both relating to battery storage options.
- The medium-term options identified in the PSCR for further increasing transfer capacity will be progressed through a separate RIT-T process at a later date.

As outlined in section 2, this PADR focusses on credible options for increasing transfer capacity between New South Wales 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.

Stakeholder consultation on the PSCR has enabled two new credible options to be defined and assessed as part of this PADR, i.e., in addition to the four incremental credible options to increase transfer capacity identified in the PSCR. These new options reflect:

- a 'modest' 2 x 40MW/20MWh BESS (Option 5A); and
- a refinement of the delivery, costs and capabilities of the original, larger, BESS option proposed in the PSCR (which is now assumed to be a 2 x 200MW/100MWh system) (Option 5B).

The table below updates and summarises the six credible options assessed.[62] All credible options are expected to be delivered and inter-network testing completed by June 2022.

**Table 3 Summary of credible options assessed as part of this PADR**

| Option description | Indicative total transfer capacity (MW)[63] | | 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 | 175 |
| Option 1B – Uprate Liddell to Tamworth lines only | 570 | 1,070 | 34 |
| Option 1C – Install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks | 480 | 1,120 | 142 |
| Option 1D – Sapphire substation cut into line 8C and a mid-point switching station between Dumaresq and Bulli Creek | 480 | 1,110 | 45 |
| *A 'virtual transmission line' comprised of grid-connected battery systems* | | | |

62 The same option naming/numbering convention has been applied as in the PSCR for consistency, i.e., 'Option 1' for the incremental upgrades to the existing network to increase transfer capacity and 'Option 5' for the grid-connected battery systems.

63 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 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 has resulted in refining the definition of the QNI transfer capacity.

| Option description | Indicative total transfer capacity (MW)[63] | | Estimated capex ($m) |
|---|---|---|---|
| | Northward | Southward | |
| Option 5A – Small BESS (2 x 40MW/20MWh) | 520 | 1,110 | 110* |
| Option 5B – Large BESS (2 x 200MW/100MWh) | 680 | 1,270 | 461* |

** These are the assumed upfront capital and reinvestment costs for these two options.*

All options are assumed to have annual operating costs equal to approximately 1 per cent of their capital costs.

The BESS options have been assessed using information (including costs) provided by parties in response to the PSCR and in subsequent engagement with TransGrid and Powerlink. However, in order to maintain confidentiality of commercial-in-confidence information in submissions, the analysis presented in this PADR has used public generic storage costs. The use of generic costs does not alter the outcomes of the assessment in terms of which option is preferred overall.

On 12 November 2018, the New South Wales Government released the NSW Transmission Infrastructure Strategy stating 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 are working with the New South Wales Government on this initiative.

The remainder of this section provides further detail on each of the six credible options assessed as part of this PADR. It also summarises all options that have been considered but not progressed to-date as part of this RIT-T (and the reasons why).

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).

## 5.1 Incremental upgrades to the existing network to increase transfer capacity

This PADR continues to assess the four incremental upgrades to the existing network to increase transfer capacity. Each of these is summarised in the sub-sections below.

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

Overall, this RIT-T reflects significant additional work to assess each of the potential credible options since the 2018 ISP was released. This has included quantifying capacity improvements based on detailed power system modelling to develop an updated assessment of the impact on transfer capacity,[64] and refining the cost estimates for each of the options.

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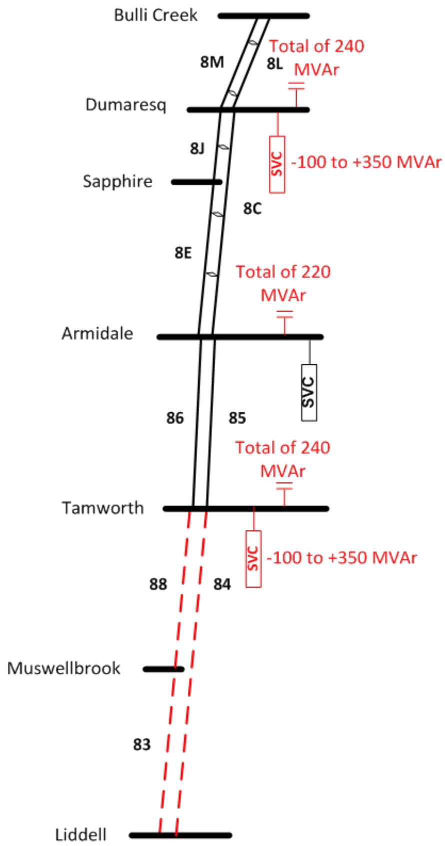
64 Specifically, six operating conditions have been investigated (under various changes to significant variables, e.g. Sapphire generation level) for each option representing boundary and typical conditions made up of the combinations of summer day and night time operation under high, medium and low load conditions.

### 5.1.1 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.

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 25. These lines would be uprated from the existing design operating temperature of 85°C to 120°C.

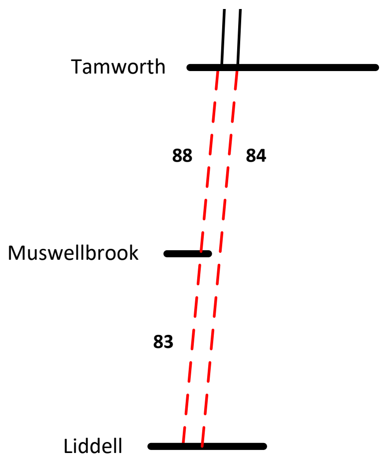
The second component targets both northerly and southerly QNI stability limits by installing dynamic reactive support at both the Tamworth and Dumaresq 330 kV substations, and installing additional 330 kV shunt connected capacitor banks at Tamworth, Armidale and Dumaresq 330 kV substations.

In the PSCR, we highlighted three alternate options for the provision of dynamic source of reactive support under Option 1A, i.e., static VAr Compensator (SVC), static synchronous compensator (STATCOM) and a synchronous condenser. We have now ruled out the use of a synchronous condenser due to the materially higher cost associated with it (and absence of commensurate benefits), but are continuing to assess which of the other two technologies is considered optimal and will report the outcome in the PACR. For the purposes of describing this option in this PADR, 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 $175 million (reflecting further option scoping and refinement since the PSCR). This option also has additional operating costs associated with refurbishing elements of the SVC in the future (these costs sum to approximately $8.5 million in total over the assessment period).

### 5.1.2 Option 1B – Uprate Liddell to Tamworth lines only

Option 1B involves only the first component of Option 1, 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.




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.

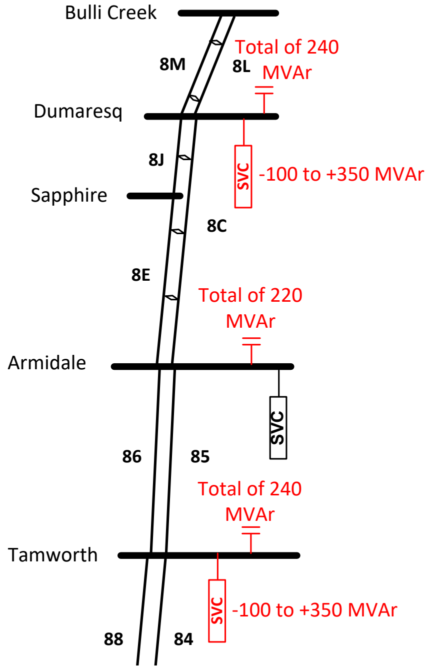
The estimated capital cost of Option 1B is $34 million (reflecting further option scoping and refinement since the PSCR).

### 5.1.3 Option 1C – Install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks

Option 1C involves only the second component of Option 1A, i.e., installing new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks, as described in section 5.1 above. It remains fundamentally the same as defined in the PSCR.

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 $142 million (reflecting further option scoping and refinement since the PSCR). As with Option 1A, this option also has additional operating costs associated with refurbishing elements of the SVC in the future (these costs sum to approximately $8.5 million in total over the assessment period).




### 5.1.4 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.

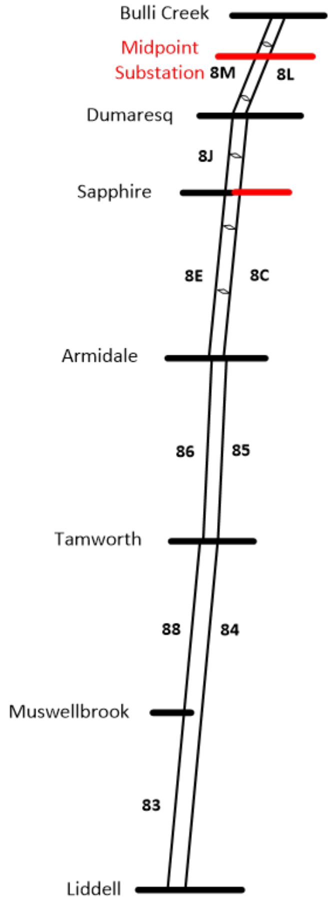
In particular, Option 1D involves:

- 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 $45 million (which remains unchanged from the PSCR).



## 5.2 A 'virtual transmission line' comprised of grid-connected battery systems

Consultation with a number of parties following the PSCR has enabled the initially proposed BESS option in the PSCR to be further refined. In addition, it has enabled a new credible option involving a smaller BESS to be defined and assessed.

These options target both northerly and southerly QNI stability and thermal limits by installing a BESS, controlled by a System Integrity Protection Scheme (SIPS) at two ends of the QNI corridor. The operation of each BESS would mimic a 'virtual transmission line' following a transmission line contingency.

Submitters to the PSCR requested that the costs proposed be kept confidential and so, for the economic assessment presented in this PADR, we have used generic cost inputs for BESS systems. Specifically, we have assumed:

- BESS capital costs sourced from a workshop Aurecon ran with AEMO in August 2019 to summarise work in progress on the generator and storage cost and technical parameters review;[65]
- a 15 year asset life (sourced from AEMO's 2020 ISP assumptions); and
- a 60 per cent fall in real costs by the time the BESS needs to be reinvested in (sourced from Bloomberg New Energy Finance).

The costs of these options also include the cost of the required network connection assets, which have been estimated by TransGrid and Powerlink.

While the two BESS options presented in this PADR assume generic cost inputs for capital assets, we have also modelled these options using the costs and ownership structures proposed by proponents (i.e., both network-owned and third-party-owned) and do not find these to change the overall finding of the assessment in terms of the overall preferred option. These assessments have not been presented in the PADR for confidentiality reasons.

In addition, we consider that the treatment of these options in the PADR assessment is optimistic for a range of technical operational reasons. In particular, a range of likely operational realities have effectively been assumed away in the PADR assessment of the BESS options in order to determine whether they might deliver comparable net benefits to the incremental network options. In practice, these operational realities may not be as favourable and may reduce the benefits quantified in the PADR assessment. Of note, 30 minute capacity has been modelled, which may not be a sufficient duration to resecure the system under some conditions.[66]

### 5.2.1 Option 5A – Small-scale BESS (2 x 40MW/20MWh)

As outlined in section 4.1, parties suggested in their submissions that a smaller BESS than that proposed in the PSCR may add incremental net benefits. Further, two of these parties provided details on the suggested size of such a BESS, which was a 40MW battery in both cases.

TransGrid and Powerlink have met with each of these parties to understand each of their proposals further and developed Option 5A based on one submitter's proposal (the other submitter subsequently withdrew their offer to provide a small-scale battery).

Option 5A involves installing 2 x 40MW BESS connecting in both New South Wales and Queensland.

While the structure and level of costs proposed by the submitter have been requested to be kept confidential, we have used a generic upfront capital cost estimate for this option (as outlined above) of $59 million. The asset

[65] Aurecon, *2019 Cost and Technical Review – Workshop Discussion with AEMO*, 14 August 2019.

[66] While the NER requires AEMO to resecure the power system within no more than 30 minutes following a contingency, the BESS have been modelled assuming that the battery is normally operated at half charge to extend both southerly and northerly limits. This would mean that AEMO would have only around 15 minutes (depending on the speed of actions and the sophistication of the scheme) to resecure the system. This is considered the minimum time for NEMDE to resecure the system but has not been tested or confirmed at this stage.

life of the BESS is assumed to be 15 years, and reinvestment is required within the assessment period (the cost of which is assumed to be 40 per cent of the upfront capital cost due to expected future cost reductions).

This option also involves $27 million in additional capital cost associated with connecting to the transmission networks.

### 5.2.2 Option 5B – Larger-scale BESS (2 x 200MW/100MWh)

Consultation on the PSCR has enabled this option to be refined in the PADR analysis. Specifically, submissions from, and subsequent bilateral discussions with, parties who have requested to remain confidential has resulted in this option:

- involving a 200MW BESS in the near-term; and
- assumed connection to the Calvale substation in Queensland (as opposed to Halys substation) due to an increased ability to relieve intra-regional constraints.

The BESS is still assumed to connect at the Liddell 330 kV substation in New South Wales and be controlled by a SIPS to control power targets depending on critical contingencies on the QNI and CQ-SQ corridors.

As outlined in section 4.1, two parties offered a BESS as network support and one party offered a BESS as a network-owned asset.

While the structure and level of costs proposed in submissions have been requested to be kept confidential, we have used a generic upfront capital cost estimate for this option (as outlined above) of $300 million. The asset life of the BESS is assumed to be 15 years, and so reinvestment is required within the assessment period (the cost of which is assumed to be 40 per cent of the upfront capital cost).

This option also involves $41 million in additional capital cost associated with connecting to the transmission networks.

## 5.3 Options considered but not progressed

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

### 5.3.1 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. This is primarily due to the timeframes in which the identified need needs to be met.

### 5.3.2 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 4.

**Table 4 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.<br>This option is therefore not considered technically feasible. |
| 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.<br>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.[67] 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.

[67] 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

# 6. 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.

## 6.1 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.[68] 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 PADR 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 PADR).

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 this PADR.

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[68] 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 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 KerangLink). 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 5 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.<br>'4 degree' scenario for Pumped Hydro. | AEMO Feb 2019 '4 degree' scenario. | | |
| Retirements of coal fired power stations[69] | Half of station's capacity retired 5 years earlier than Neutral.<br>Liddell 2022 fixed | Retired by AEMO Feb 2019 announced retirement date or end-of-technical-lives, except Eraring 2031.<br>Liddell 2022 fixed | Half of station's capacity retired 2 years earlier than Neutral.<br>Liddell 2022 fixed | Half of station's capacity retired 5 years later than Neutral.<br>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 |
| VRET | 25% renewable energy by 2020[70], 40% renewable energy by 2025 and 50% renewable energy by 2030 | | | |
| QRET | 50% by 2030 | | | |

69 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.

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

| Key drivers input parameter | Fast change scenario | Neutral scenario | Neutral + low emissions scenario | Slow change scenario |
|---|---|---|---|---|
| South Australia Energy Transformation RIT-T | The proposed SA to NSW interconnector is assumed commissioned by July 2023[71]<br>Project EnergyConnect 800 MW bi-directional<br>VIC-SA 750 MW bi-directional<br>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<br>600 MW bi-directional | Excluded | | |
| Victoria to NSW Interconnector Upgrade | The preferred option is assumed commissioned by July 2020<br>North 870 MW, South 400 MW | | | Excluded |
| Snowy 2.0 generation, HumeLink and KerangLink | Snowy 2.0 generation and HumeLink will be included by 2025<br>The preferred KerangLink ISP option is assumed commissioned by July 2026[72]<br>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.[73]

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).[74] While this deferred retirement for these three units has not been able to be reflected fully in the PADR analysis (due to the recent timing of the announcement), we have included a sensitivity that investigates the effects of this retirement schedule (see section 8.6).

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 have carried out a sensitivity to investigate the impact to Wood Mackenzie's 'fast' coal price scenario, which is discussed in section 8.6.

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 will consider the impact of any material changes in assumptions since that time in the PACR. In addition, should the timing of any coincident developments change (e.g., the proposed new interconnector between New South Wales and

71 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.

72 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.

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

74 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

South Australia[75]) prior to the PACR, the materiality of this change for the assessment in this RIT-T will also be assessed in the PACR.

## 6.2 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 8), we have also carefully considered the results in each scenario in section 8.

As outlined in section 8.5, the assessment in this PADR finds that the preferred option is invariant to the scenarios investigated and so independent of the weightings applied.

## 6.3 Sensitivity analysis

In addition to the scenario analysis, we have also 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 this PADR are:

- 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 the sensitivity tests are discussion in section 8.6. As part of this, we have also 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 above list of sensitivities represents a focus on the key variables that could impact the identified preferred option.

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[75] 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

# 7. 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 PADR.
- Wholesale market dispatch modelling has been used to estimate these categories of market benefits.
- The market modelling assumptions and inputs have been updated since the PSCR to more closely align with those to be used for the 2020 ISP, which were consulted on by AEMO during early 2019.
- A separate modelling report will be released alongside this PADR that provides greater detail on the modelling approaches and assumptions, including details on the technical constraints adopted.

As outlined in section 3, 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.[76]

A proportionate approach has been taken to modelling the market benefits associated with Option 5A given its similarity to Option 5B and the computational requirements to undertake market modelling. Specifically, instead of undertaking comprehensive market modelling of this option directly, it has instead been modelled by the pro-rata of modelled gross market benefits for Option 5B. This is considered a proportionate approach to estimating the net benefits associated with this option and has been coupled with a threshold analysis, which finds that Option 5A would need to deliver approximately 61 per cent of Option 5B's estimated benefits to be ranked equally with the preferred option, Option 1A (as set-out in section 8.1).

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

## 7.1 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 PADR 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;

[76] 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 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.

### 7.1.1 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 7.1 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.

### 7.1.2 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 this PADR, 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.

### 7.1.3 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.

### 7.1.4 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.

### 7.1.5 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 in this PADR. 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.

## 7.2 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 have 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 have 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.

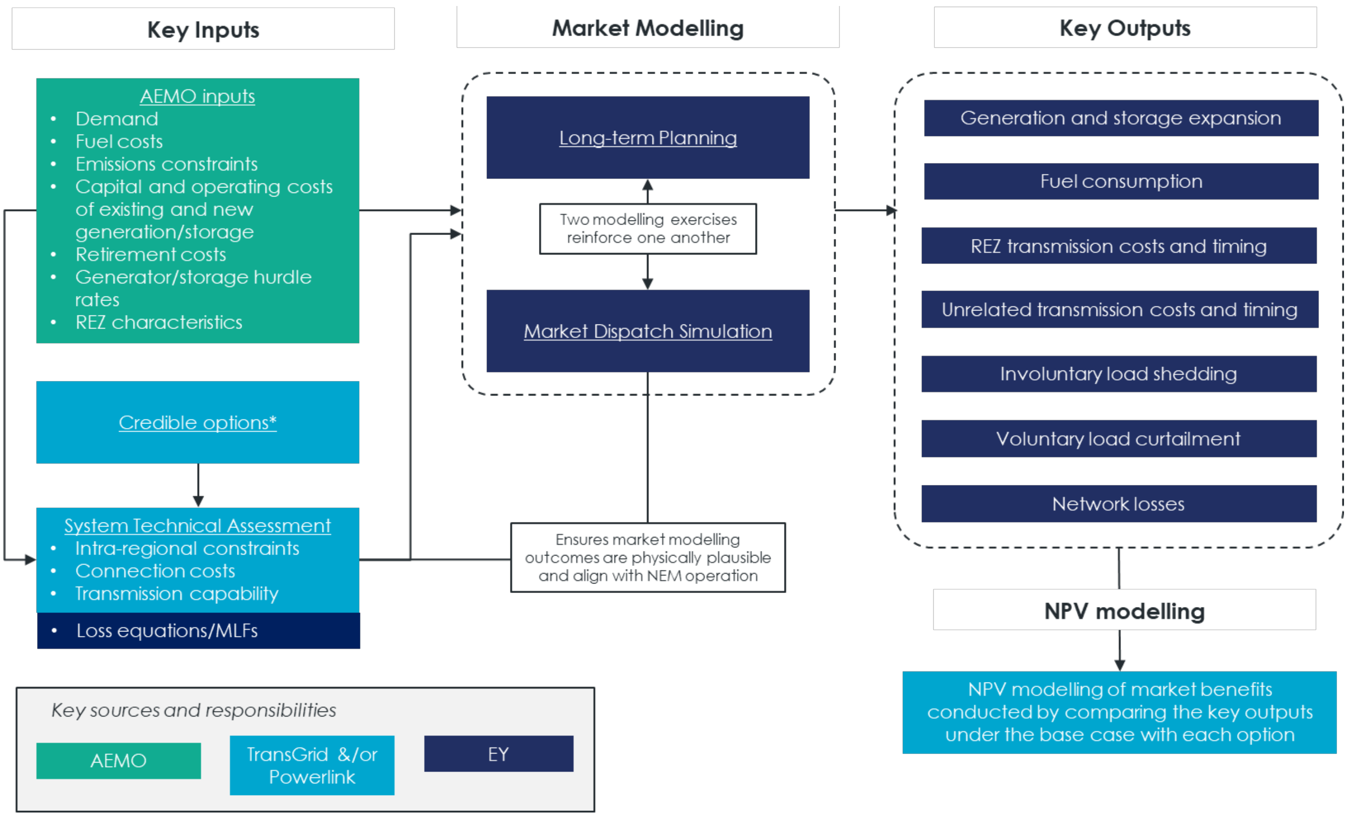
The first solves for the least-cost generation and transmission infrastructure development across the assessment period while meeting energy policies, whereas the second investigates the resulting generation and transmission infrastructure development from a deeper operational perspective. In short, 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 5 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 5 – Overview of the market modelling process and methodologies**




** Note that options 5A and 5B have been developed jointly with submitters to the PSCR, as outlined in sections 4 and 5 above.*

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 have undertaken as part of this PADR assessment. 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.

### 7.2.1 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).[77]

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.[78] EY have 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.[79]

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

78 Stakeholder webinar summary, pp 3-4.

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

The market modelling report accompanying this PADR 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.

### 7.2.2 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.

### 7.2.3 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 PADR.

### 7.2.4 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.

## 7.3 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 this PADR. 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,[80] 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).[81] This consistency with the 2020 ISP is also in accordance with the anticipated actionable ISP rule changes.

## 7.4 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.[82]

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 this PADR since they do not exhibit flexibility. 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.[83] In addition, we have tested as part of this PADR only performing discrete components of the preferred option (i.e, Option 1B and Option 1C are the two components making up Option 1A) and these were not found to be as economic.

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80 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

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

82 NER clause 5.16.1(c)(6).

83 For example, a new line may be able to 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).

# 8. Net present value results

**Summary of key points:**

- Option 1A is found to deliver the greatest net benefits of all credible options across all four scenarios investigated – net benefits range from around $80 million to $290 million.
- On a weighted-basis, Option 1A is estimated to provide around 25 per cent greater net benefits than the second-ranked option (Option 1B).
- 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 and Queensland under each option allows existing and new Queensland generation to export to New South Wales, reducing the need for new investment in New South Wales.
- While Option 5B is the top-ranked grid-connected BESS option, and has the greatest estimated gross benefit of all options, it is only expected to deliver around 60 per cent of the expected net benefits of Option 1A on a weighted-basis (which is driven by the relatively high costs associated with Option 5B).
- These conclusions are robust to a range of sensitivity tests and more robust 'threshold tests'.

## 8.1 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.

The PADR assessment finds that Option 1A provides the greatest expected net benefit under these assumptions. Option 1A is estimated to deliver approximately $220 million in net benefits, which is around 46 per cent greater net benefits than those estimated for the second-ranked options (options 1B and 5B).

Figure 6 shows the overall estimated net benefit for each option under the neutral scenario.

**Figure 6 – Summary of the estimated net benefits under the neutral scenario**

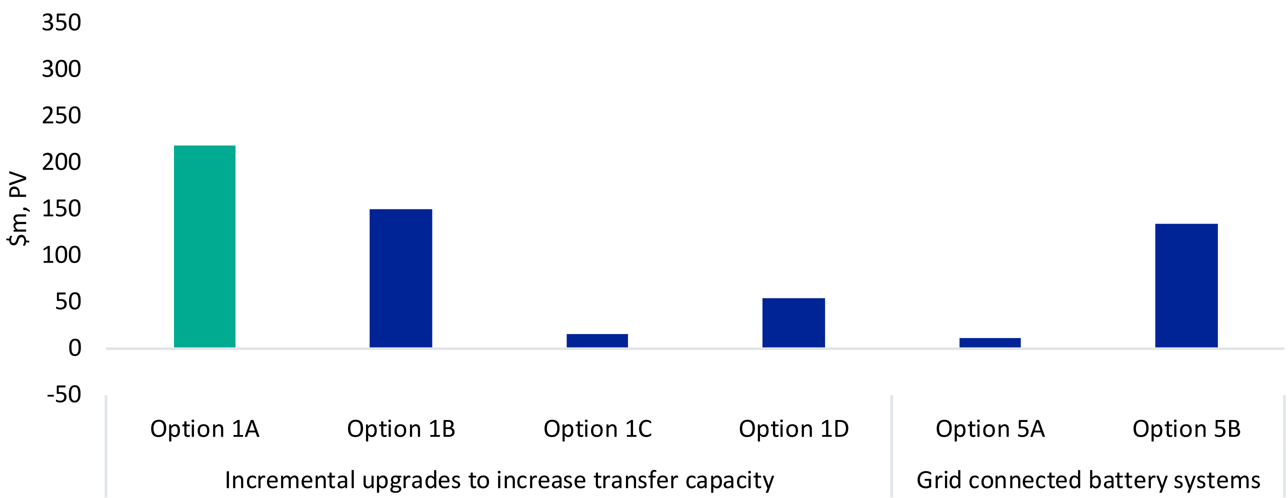
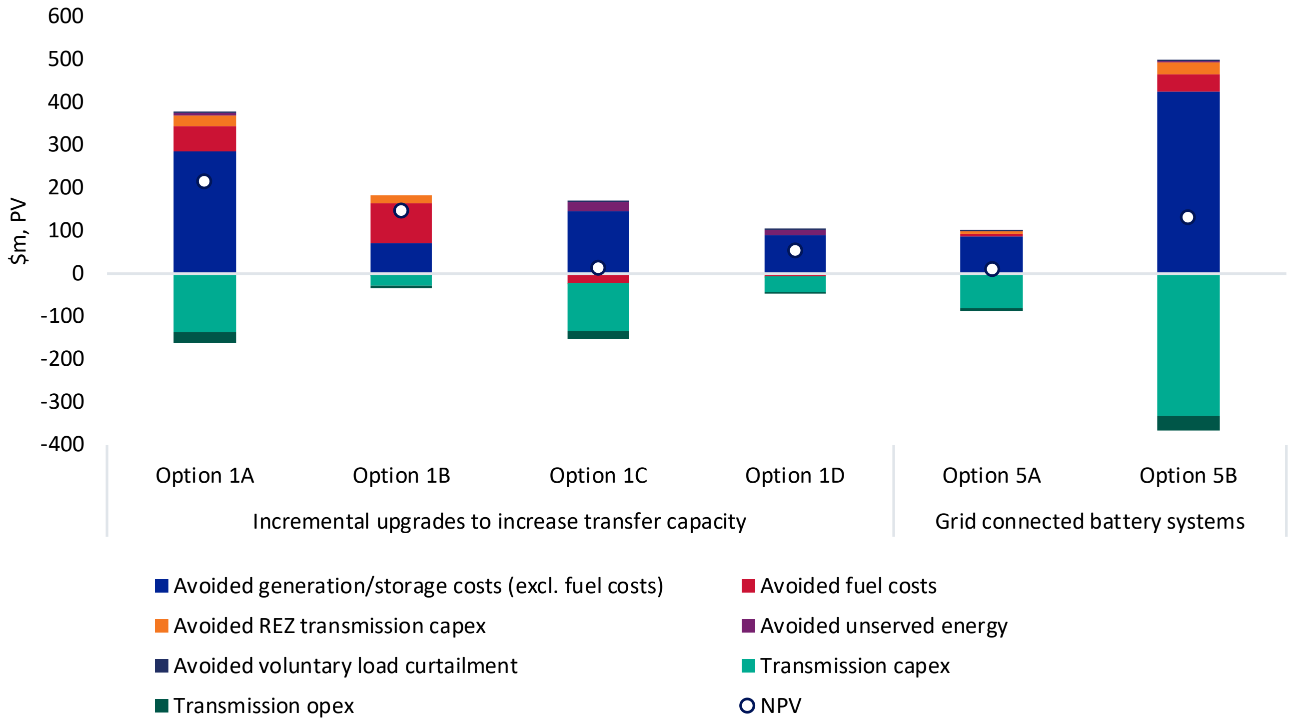



Figure 7 shows the composition of estimated net benefits for each option under the neutral scenario.

**Figure 7 – 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 7).
  - This benefit arises since the expanded transfer capacity between New South Wales and Queensland under each option allows existing and new Queensland generation to export to New South Wales, reducing the need for new investment in New South Wales.
  - 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 the preferred option enables significant investment in new OCGT in New South Wales 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 is 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 New South Wales coal generation and gas plant (both existing and new).
- Option 1B is estimated to deliver the smallest amount benefit from avoided, or deferred, costs associated with generation and storage of all the options.
  - Option 1B offers limited benefit in serving central New South Wales 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 New South Wales). As a result, in the early years more capacity must be built locally in central New South Wales to meet peak demand, plus the reserve requirement, with Option 1B compared to Option 1A (which does provide reactive support).

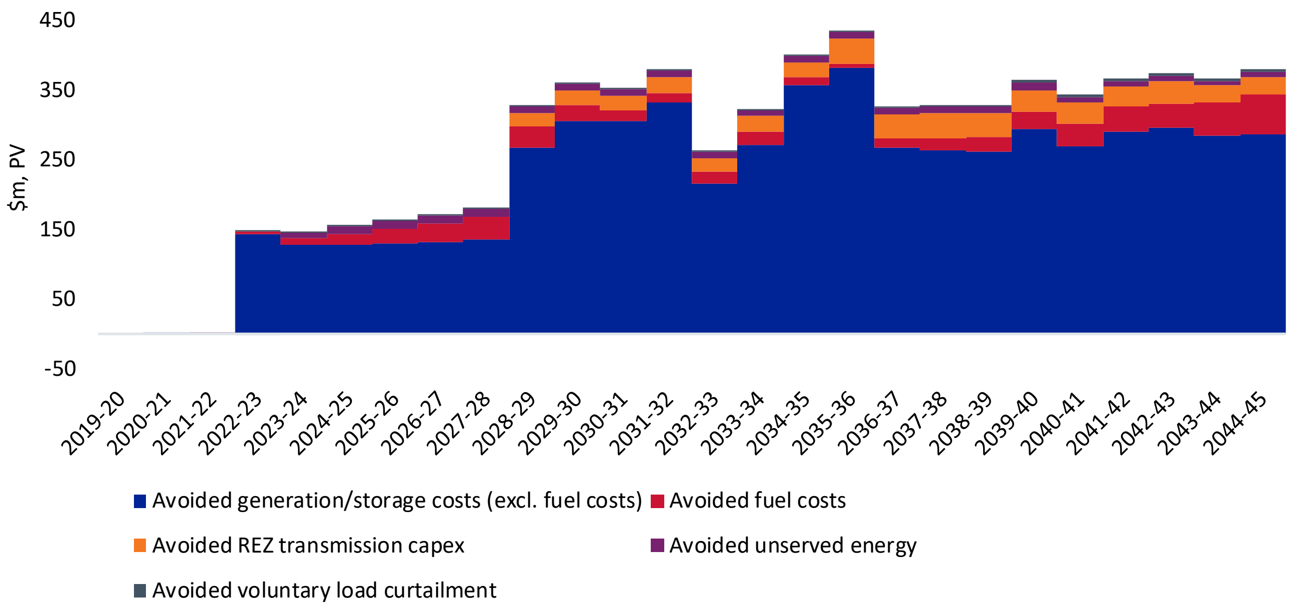
- Option 1C and 1D have the lowest estimated net benefits of the incremental upgrade options.
  - This is because these two options do not increase the limit between central and northern New South Wales, meaning they have limited benefit in serving central New South Wales peak demand in the near term (and so new capacity must be built locally).
- While Option 5B provides the greatest gross benefits, driven by the fact that it delivers the largest increase in transfer capacity of all options, it is only expected to deliver around 61 per cent of the expected net benefits of Option 1A under this scenario.
  - This is because this option has relatively high upfront capital costs, as well as the BESS assets having comparatively shorter asset lives (and so needing reinvestment during the assessment period).

The small BESS provides negligible net benefits (in the order of those estimated for Option 1C), which is driven by the fact that the 40MW system does not materially increase the transfer capacity between the states and so is not forecast to provide a significantly different set of market outcomes to the base case. As outlined at the start of section 7, a proportionate approach has been taken to modelling the market benefits associated with Option 5A whereby it has been modelled by the pro-rata of the modelled benefits of Option 5B.

We have stress tested this pro-rata assumption and find that Option 5A would need to deliver approximately 61 per cent of Option 5B's estimated benefits to be ranked equally with Option 1A under the neutral scenario, which is not considered feasible given it represents only 20 per cent of Option 5B's limit improvement. Specifically, as illustrated above, the majority of benefits arise from avoided, or deferred, costs associated with generation and storage, which is highly dependent on limit improvements.

Figure 8 below presents the estimated cumulative expected gross benefits for Option 1A for each year of the assessment period under the neutral scenario.[84]

**Figure 8 – Breakdown of cumulative gross benefits for Option 1A under the neutral scenario[85]**




84 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 7 above.

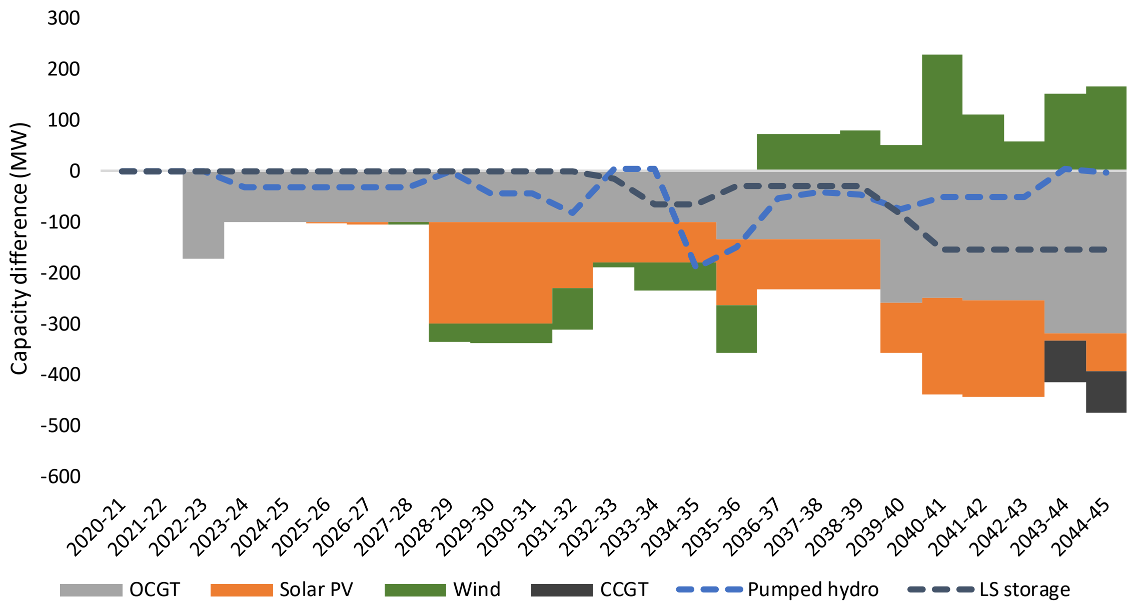
85 While all generator and storage capital costs have been included in the market modelling on an annualised basis, this chart, and all charts of this nature in the PADR, present the entire capital costs of these plant in the year avoided in order to highlight the timing of the expected market benefits. 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.

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 8 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 Option 1A 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 9 summarises the difference in generation and storage capacity modelled for Option 1A (in GW), compared to the base case.

**Figure 9 – Difference in capacity built with Option 1A, compared to the base case, under the neutral scenario**




## 8.2 'Neutral + low emissions' scenario

The 'neutral + low emissions' scenario assumes 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.

Option 1A is found to provide the greatest expected net benefit under this state of the world. Option 1A is estimated to deliver approximately $220 million in net benefits, which is around 10 per cent more than the second-ranked option (Option 1B).

Figure 10 shows the overall estimated net benefit for each option under the 'neutral + low emissions' scenario.

**Figure 10 – Summary of the estimated net benefits under the 'neutral + low emissions' scenario**

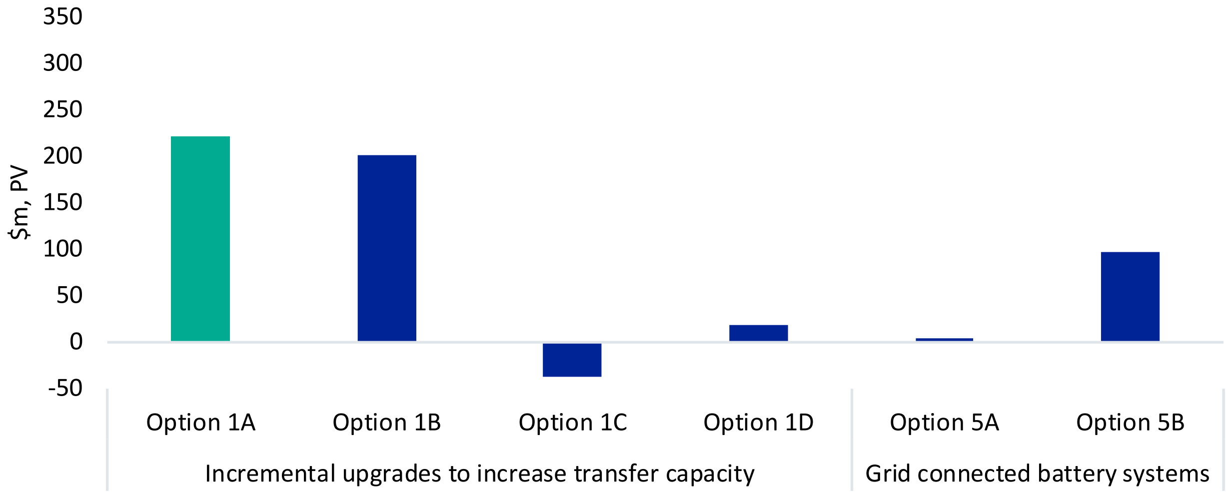
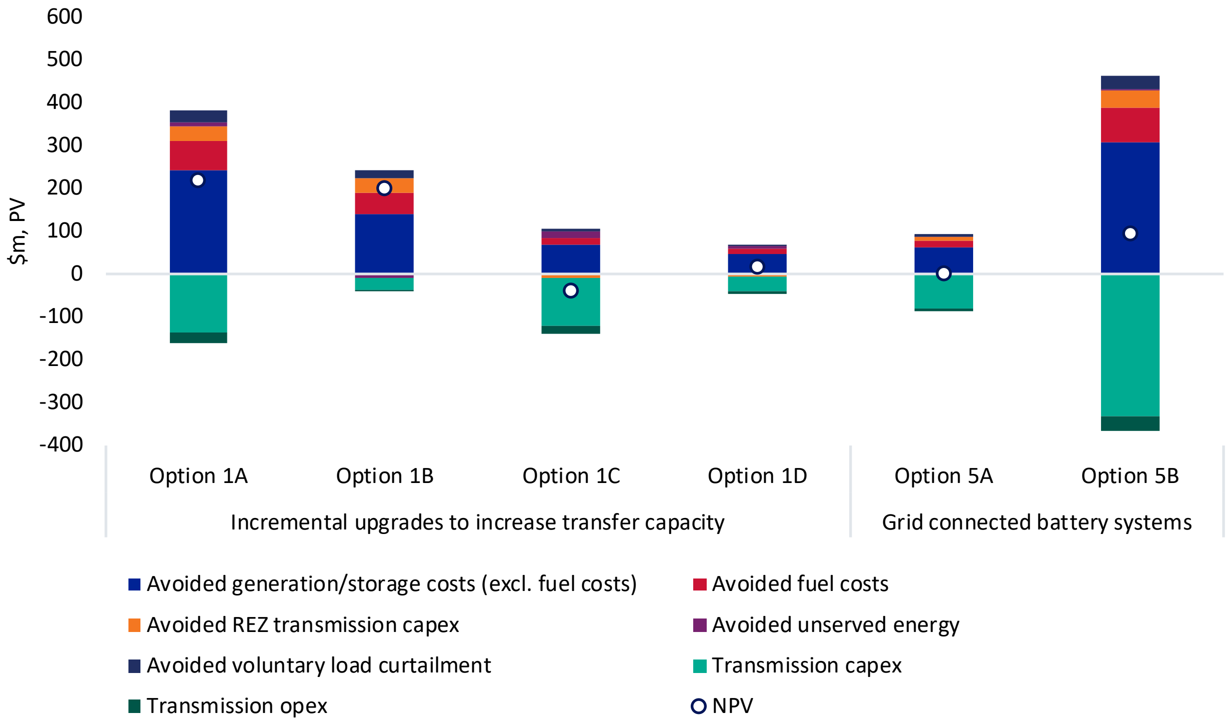



Figure 11 shows the composition of estimated net benefits for each option under the 'neutral + low emissions' scenario.

**Figure 11 – 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:

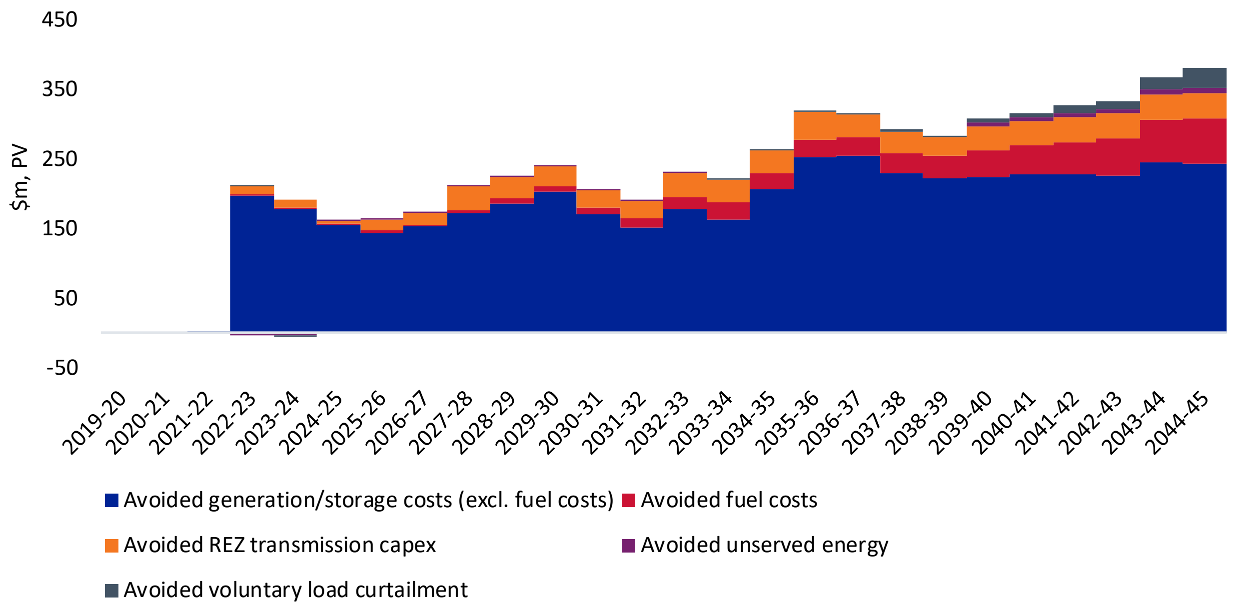
- The drivers of estimated net benefit remain the same as under the neutral scenario, i.e., the market benefits of all options are primarily derived from the avoided, or deferred, costs associated with generation and storage.
  - > However, the relativities between the specific avoided/deferred investment 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, the preferred option still enables significant investment in new OCGT in New South Wales 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 remain the same.
  > However, 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).

Figure 12 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 12 – Breakdown of cumulative gross benefits for Option 1A under the 'neutral + low emissions' scenario**




## 8.3 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 KerangLink 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 $80 million in net benefits. This represents approximately 7 per cent greater net benefits than the second-ranked option (Option 1D) and 11 per cent greater net benefits than the third-ranked option (Option 5B).

Figure 13 shows the overall estimated net benefit for each option under the slow-change scenario.

Figure 13 – Summary of the estimated net benefits under the slow-change scenario

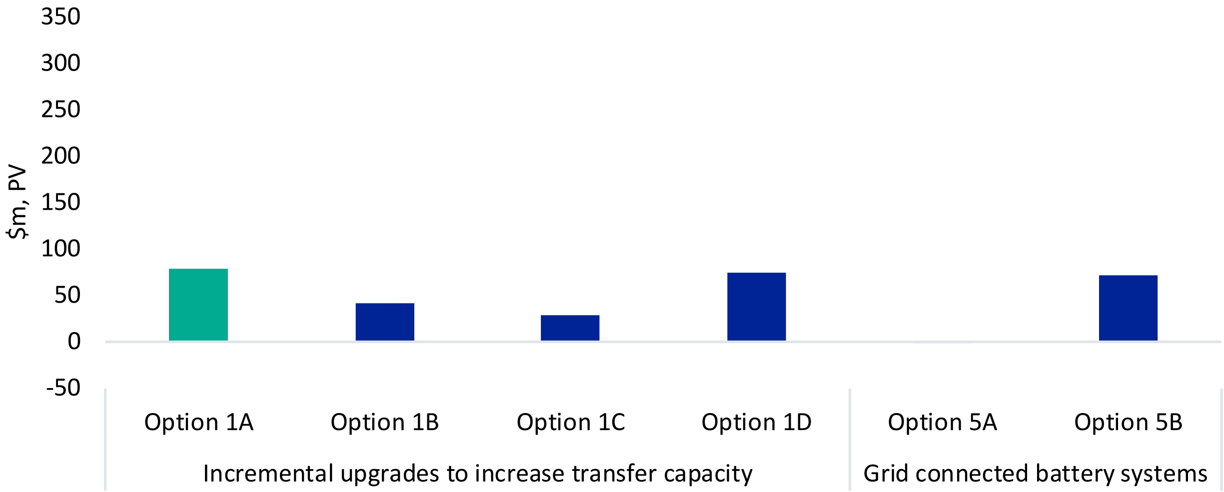
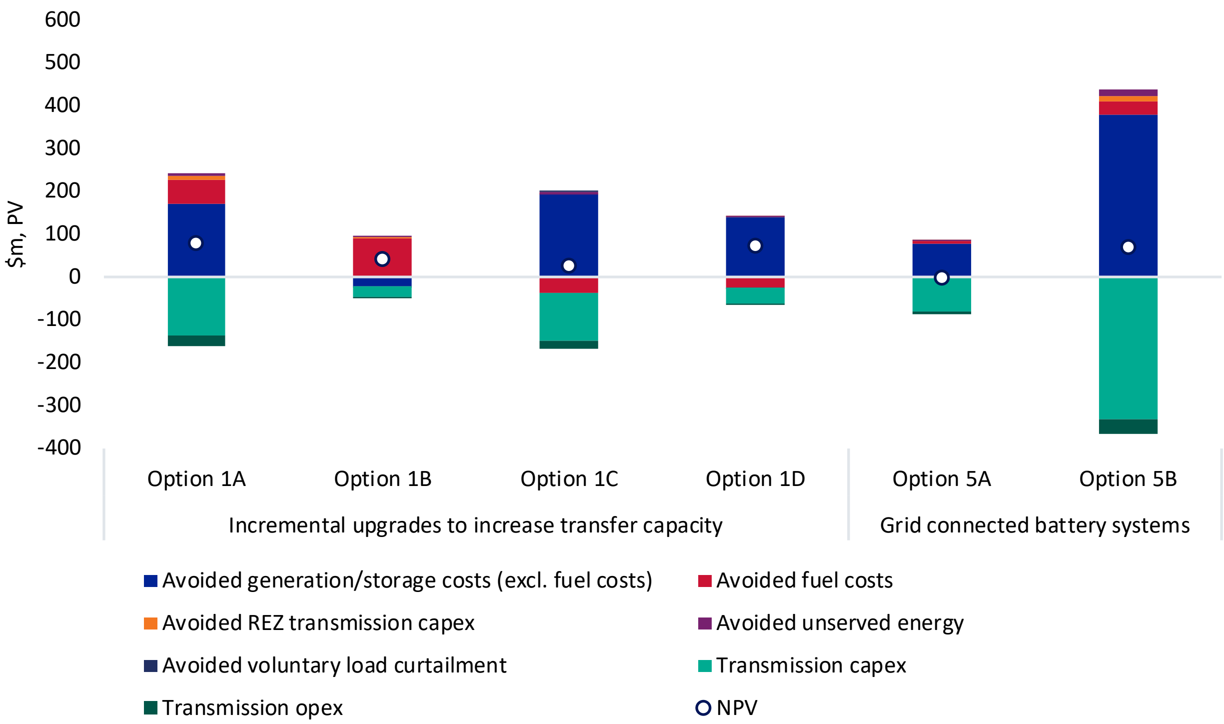



Figure 11 shows the composition of estimated net economic benefits for each option under the slow-change scenario.

Figure 14 – Breakdown of estimated net benefits under the slow-change scenario



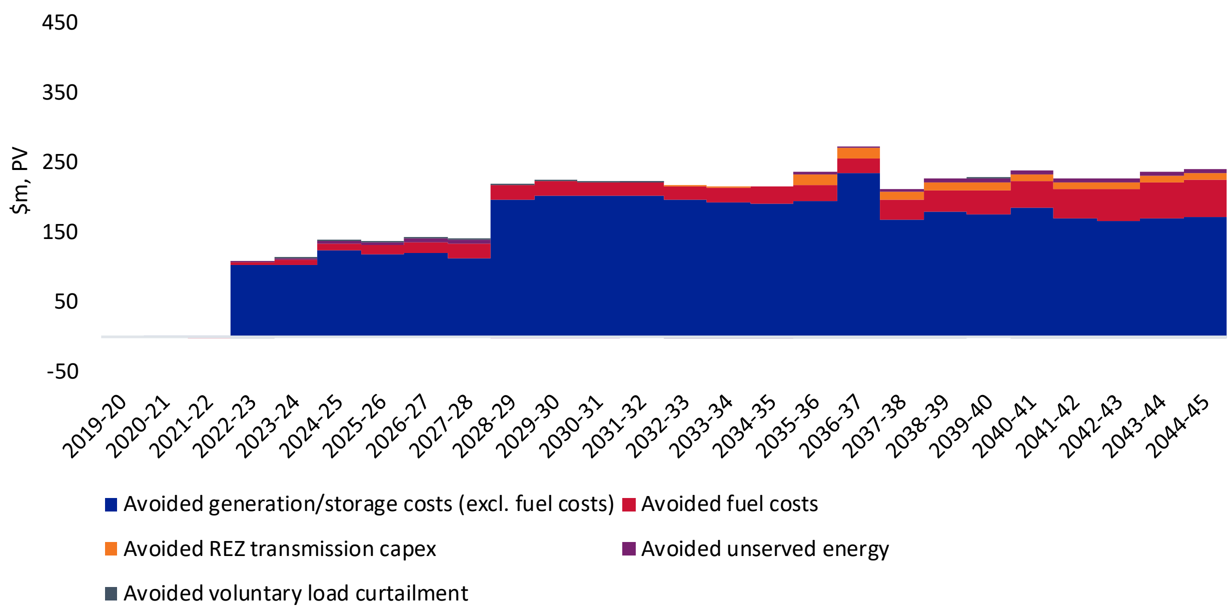

The key findings from the assessment of each option under the slow-change scenario are that:

- 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, which, as outlined in section 8.1 above, both do not increase the limit between central and northern New South Wales. Under this scenario,

both of these options avoided more solar generation build in central New South Wales from the mid-2030s (and their benefits increase slightly relative to the neutral scenario).

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




## 8.4 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.

Option 1A is found to deliver the greatest expected net benefits under these assumptions. Option 1A is estimated to deliver approximately $290 million in net benefits, which is around 14 per cent more than the second-ranked option (Option 1B).

Figure 16 shows the overall estimated net benefit for each option under the fast-change scenario.

**Figure 16 – Summary of the estimated net benefits under the fast-change scenario**

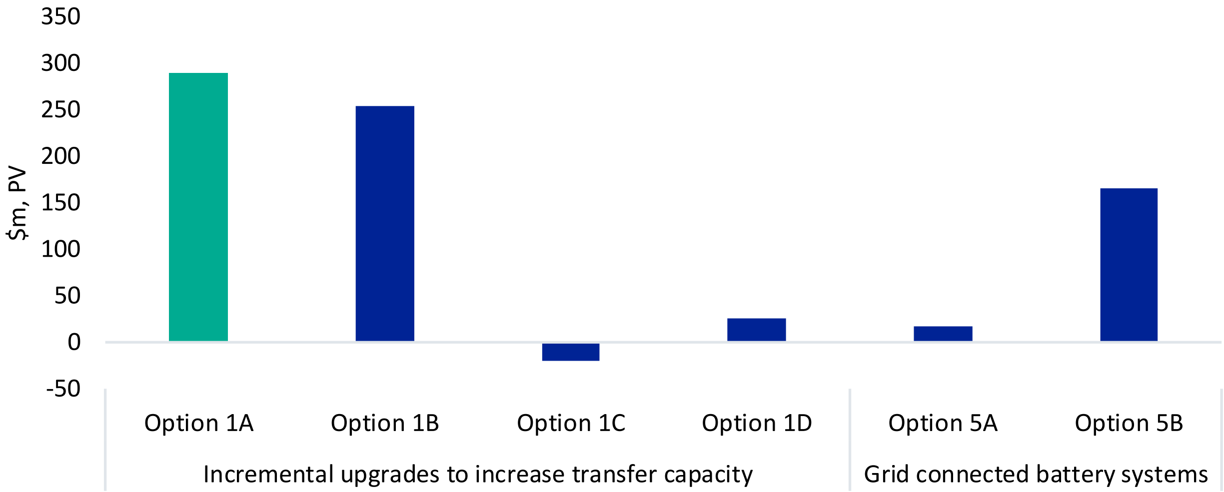
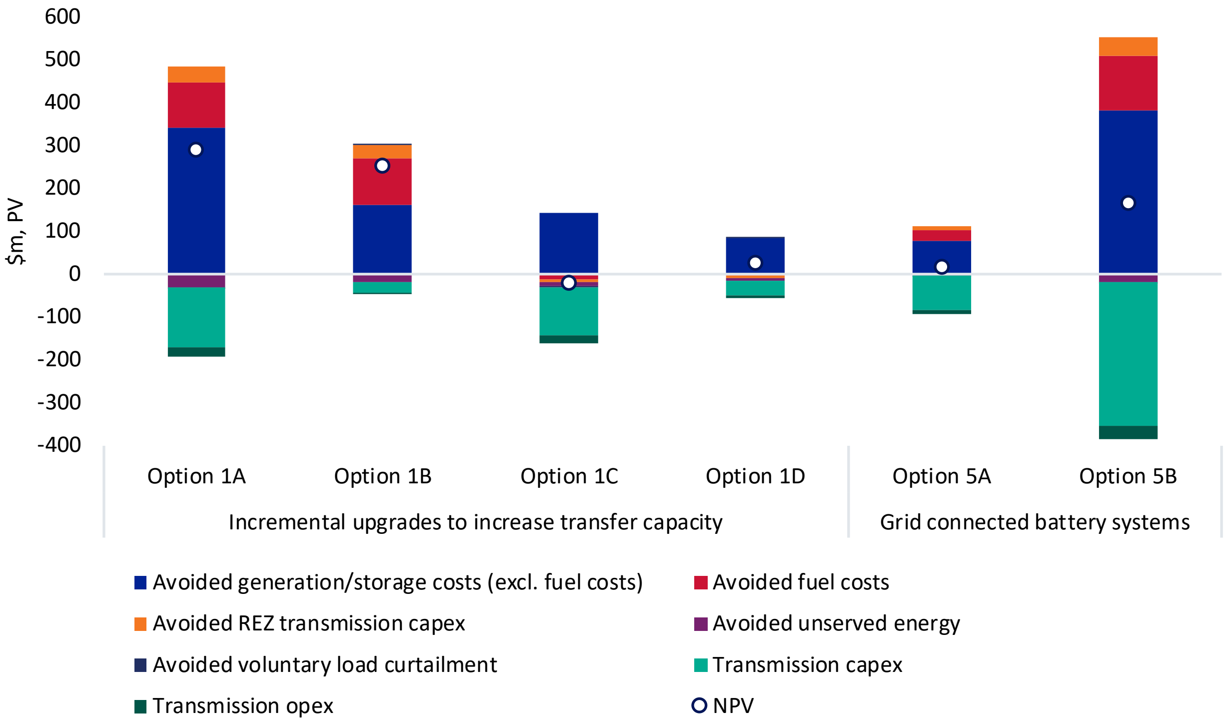



Figure 17 shows the composition of estimated net benefits for each option under the fast-change scenario.

**Figure 17 – 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.

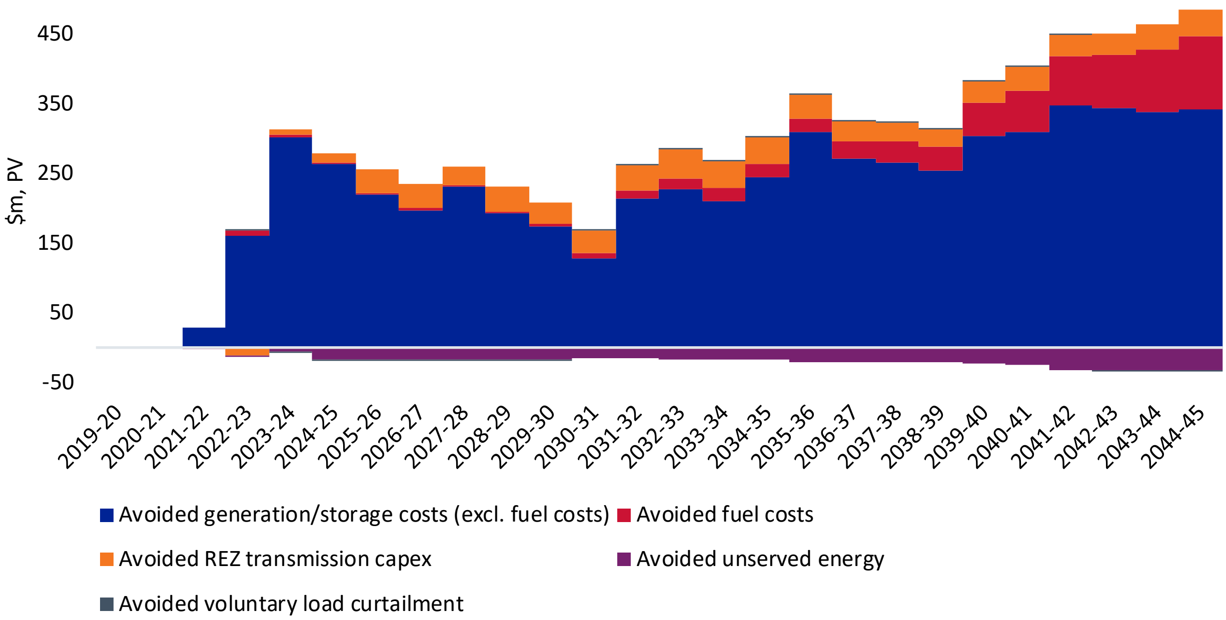
> The two exceptions to this are Option 1C and Option 1D, which, as outlined in section 8.1 above, both do not increase the limit between central and northern New South Wales. In the fast-change scenario, there is more solar built in central New South Wales than in the neutral scenario due to the higher 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 17 and Figure 18).

> 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 18 presents the estimated cumulative expected gross benefits for Option 1A for each year of the assessment period under the fast-change scenario.

**Figure 18 – Breakdown of cumulative gross benefits for Option 1A under the fast-change scenario**



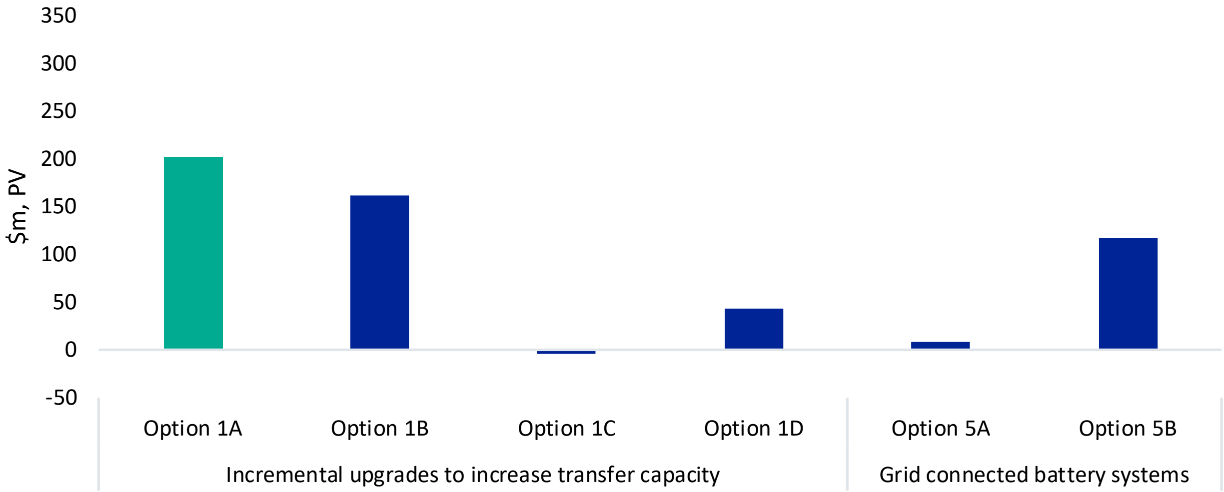

## 8.5 Weighted net benefits

Figure 19 shows the estimated net benefits for each of the credible options weighted across the four scenarios investigated (and discussed above).

Under the weighted outcome, Option 1A is expected to deliver approximately $200 million of net benefits, which is around 25 per cent greater net benefits than the second-ranked option (Option 1B).

The finding that Option 1A is the preferred option is independent of the weightings applied to the scenarios, since it is the preferred option across all scenarios investigated. We therefore consider that Option 1A is a ‘no regrets’ decision.

**Figure 19 – Summary of the estimated net benefits, weighted across the four scenarios**




The cumulative market benefits realised from the investment are expected to exceed the investment cost (in NPV terms) two years after the project is energised (on a weighted-basis). This effectively means that the economic benefits from avoiding the costs of what would have been built in Liddell's place under the base case are sufficiently high to recover the cost of Option 1A without taking into account other classes of market benefits over the assessment period.

## 8.6 Sensitivity analysis

A range of sensitivity analyses to test the robustness of the PADR modelling outcomes have been undertaken.

Specifically, we have assessed a number of sensitivities that involve additional market modelling, namely:

- deferring the 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; and
- the impact of outages during the line uprating work (as raised in submissions to the PSCR).

Each of these sensitivity tests has been designed to test the robustness of the finding that the preferred option (Option 1A) delivers positive net benefits.

The market modelling for each of the above sensitivities has not been undertaken for all credible options and scenarios. This is due to the computational time required to complete such an exercise and the fact that the four core scenarios outlined in the sections above already include significant variability in the underlying assumptions and find that Option 1A is preferred.

A range of other sensitivities that do not require market modelling have also been investigated – namely:

- higher and lower network capital costs of the credible options; and
- alternate commercial discount rate assumptions.

Each of the sensitivity tests are discussed in the sections below.

### 8.6.1 Deferred retirement of three of Liddell Power Station's units

While the four core scenarios assume that Liddell Power Station retires completely in April 2022, consistent with expectations at the time the PADR modelling assumptions were finalised, AGL announced on 2 August

2019 that the retirement of three of Liddell's four units will be deferred by one year (the one other unit will still retire in April 2022).[86]

Figure 20 shows the impact on the overall estimated net benefit for each option under the neutral scenario when it is assumed that three of Liddell's four units retire in April 2023. It shows that there are small decreases of between $1 million and $6 million in the estimated net benefits of all options, compared to the neutral scenario discussed above. Option 1A still remains the top-ranked option.

**Figure 20 – Impact of deferring the retirement of three of Liddell Power Station's units**

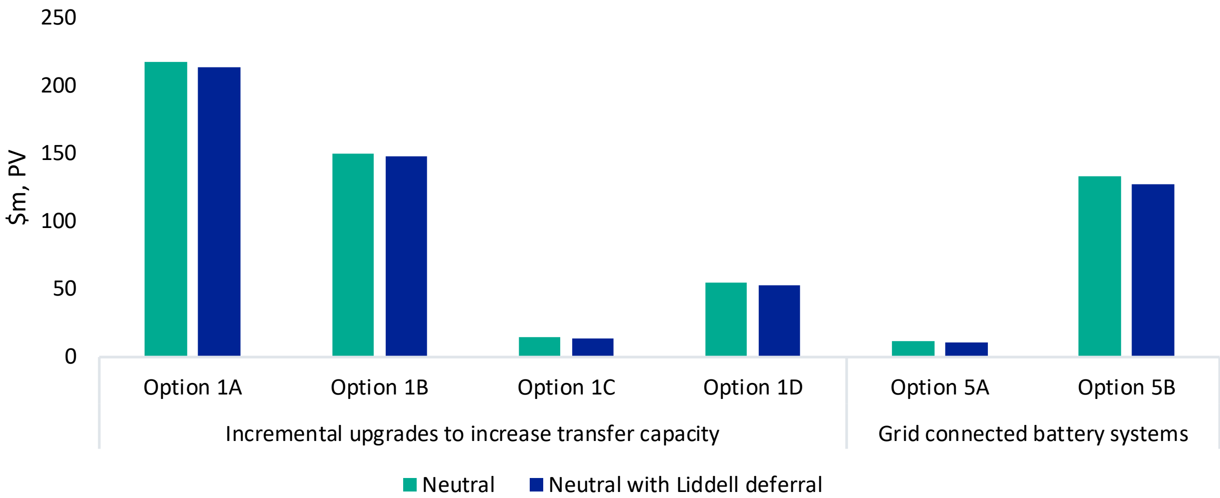
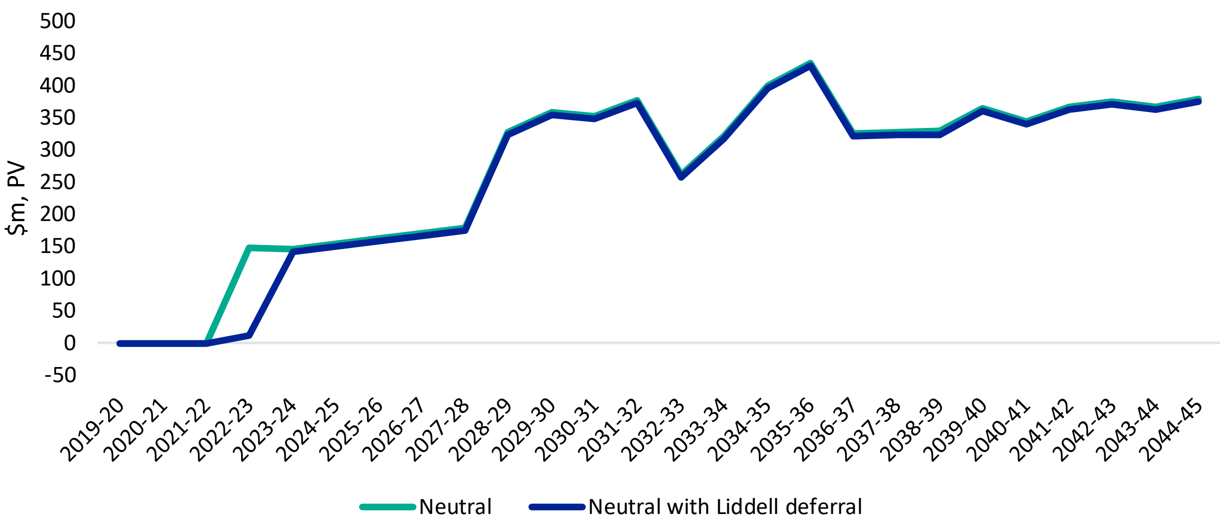



Figure 21 presents the estimated cumulative expected gross benefits for Option 1A for each year of the assessment period with the retirement of three of Liddell's four units deferred under the neutral scenario, compared to the neutral scenario modelled in section 8.1. It shows that the date benefits start to accrue is deferred by approximately a year, which is consistent with the factors driving the overall estimated net benefits presented above.

**Figure 21 – Breakdown of cumulative gross benefits for Option 1A with Liddell's retirement deferred, neutral scenario**




We have also investigated the impact on the overall estimated net benefit for each option under the 'neutral + low emissions' scenario, the slow-change scenario and the fast-change scenario when it is assumed that three of Liddell's four units retire in April 2023. These investigations find that the net benefits of Option 1A fall

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[86] 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

by approximately five per cent under the 'neutral + low emissions' scenario, 15 per cent under the slow-change scenario and three per cent under the fast-change scenario. In all scenarios, Option 1A continues to have strongly positive market benefits.

Overall, we consider that, while the estimated market benefits of the options fall marginally due to the deferred retirement, the change does not alter the outcomes of the analysis undertaken or conclusions regarding identification of the preferred option. Moreover, we consider that this deferred retirement assists with the deliverability of the preferred option and provides assurance that it will be commissioned in advance of Liddell Power Station being completely retired.

### 8.6.2 Impact of assuming Wood Mackenzie's 'fast' coal price scenario

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. 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).

This sensitivity tests the impact on the estimated net benefits of Option 1A under the ISP fast-change scenario (since this scenario reflects the set of 'fast' economic conditions).

We find that this scenario has a negligible impact on the estimated net benefits. Specifically, it is found to increase Option 1A's estimated net benefit by approximately 0.5 per cent under the fast-change scenario.

### 8.6.3 The effect of including outages during line uprating

As outlined in section 4.7, EnergyAustralia submitted that the PADR assessment should include the market impacts of any outages that are required to complete the works. These outages only apply to the line uprating options (Option 1A and Option 1B) as they require line outages while the work is performed.

We have included the effects of outages into the wholesale market modelling as a sensitivity and find that the estimated net benefits of Option 1A are reduced by around $12 million under the neutral scenario, i.e., six per cent of Option 1A's estimated net benefits under the neutral scenario without including outages during the line uprating.

The outage costs associated with lines 88, 84 and 83 applicable to Option 1A (and Option 1B) are derived from the market modelling whereby constraints are applied on QNI and the intra-regional NCEN-NNS link for a period spanning 14 months. The reduction in estimated market benefits (i.e., the 'outage cost') represents an increase in fuel costs due to displacing access to cheaper Queensland generation, which is replaced by more expensive New South Wales generation during the period of the line works. While the reduction has been computed for Option 1A, it would be the same for Option 1B as the outage costs occur prior to the augmentation (and everything is equal between these two options pre-augmentation).

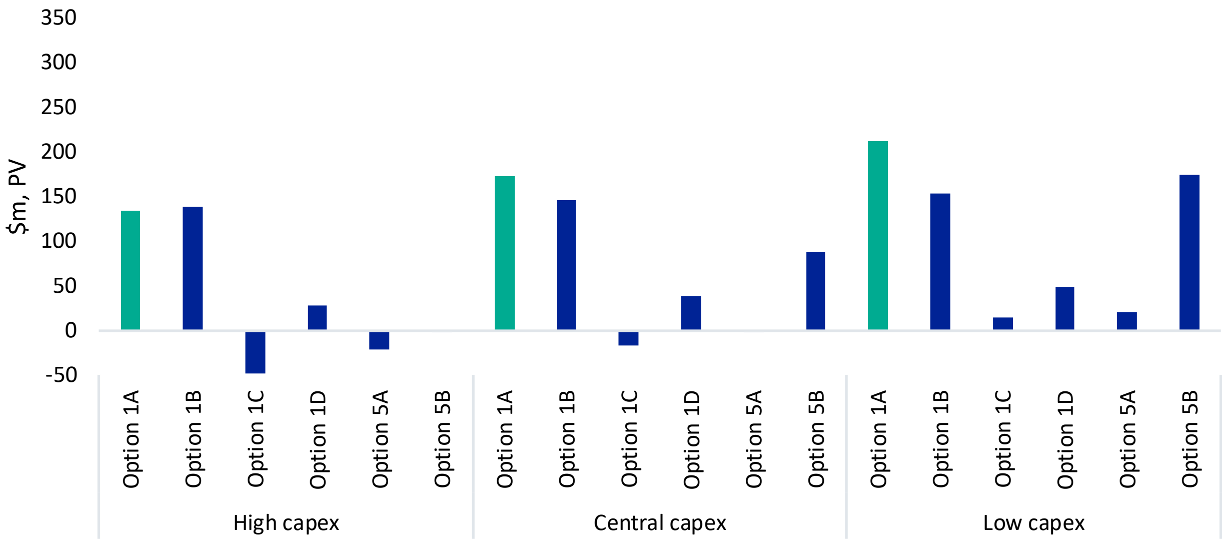
Given how strongly preferred Option 1A is under the neutral scenario, and on a weighted basis, we do not consider that including the effects of outages in all scenarios would change the identified preferred option.

### 8.6.4 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 (i.e., Options 1A-1D) and the connection costs assumed for the BESS options. 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). Hence only a threshold test between the network and BESS options was performed (detailed below).

Figure 22 shows that Option 1A remains the preferred option under 25 per cent lower and higher network capital cost assumptions (under the high capital cost sensitivity, Option 1A is effectively ranked equal-first with Option 1B).[87]

**Figure 22 – 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 61 per cent higher than the central estimates for it to be ranked equally with Option 5B (on a weighted-basis). In addition, Option 1A's capital costs would need to be at least 146 per cent higher than the central estimates for it to no longer have positive estimated net benefits (on a weighted-basis).

### 8.6.5 Alternate commercial discount rate assumptions

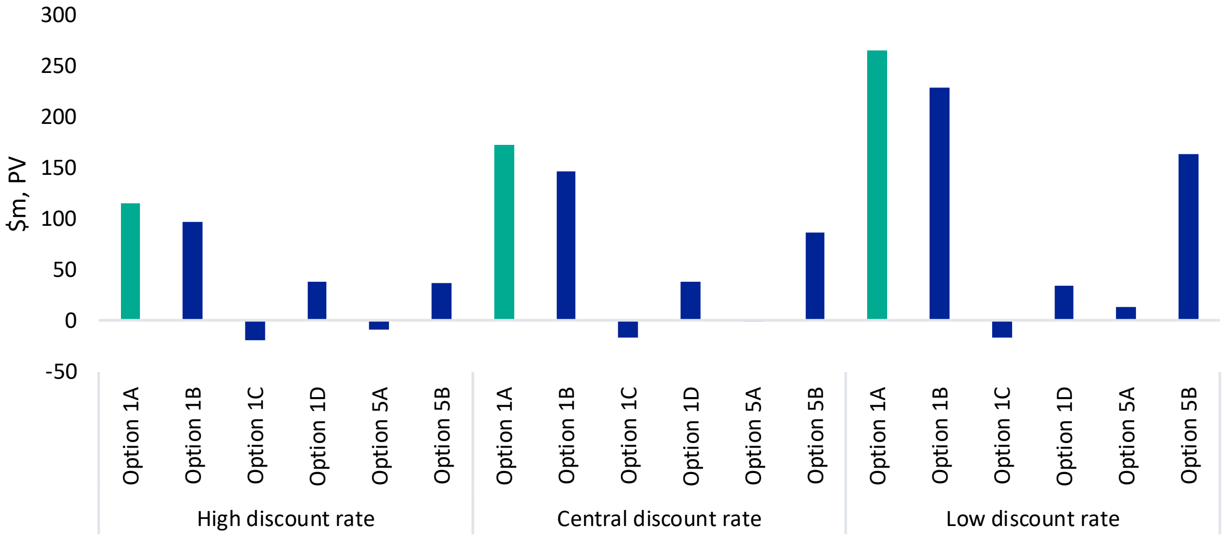
Figure 23 illustrates the sensitivity of the results to different discount rate assumptions in the NPV assessment. In particular, it illustrates three tranches of net benefits estimated for each credible option – namely:

- a high discount rate of 8.95 per cent;
- the central discount rate assumption of 5.90 per cent; and
- a low discount rate of 2.85 per cent.

Option 1A is preferred under all three different discount rate assumptions. We have extended this sensitivity and do not find a realistic discount rate that would result in Option 1A to have a negative estimated net benefit.

[87] While Option 1A has approximately four per cent lower estimated net benefits than Option 1B under the 25 per cent higher capital cost assumptions, we consider that these two options are effectively ranked equal-first under this sensitivity (due to how close the net benefits are). Moreover, since Option 1A has significantly greater estimated net market benefits than Option 1B on a weighted basis, Option 1B would not become the preferred option overall.

Figure 23 – Impact of different assumed discount rates, weighted NPVs



# 9. Conclusion

This PADR assessment shows that Option 1A is expected to deliver the greatest net benefit of all credible options considered, and across all scenarios and sensitivities investigated. This highlights Option 1A as a ‘no regrets’ decision for expanding transfer capacity between New South Wales and Queensland. Option 1A has therefore been found to satisfy the RIT-T as the preferred option.

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

The two key components of Option 1A are:

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

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 $200 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.

Capital costs for this option are estimated to be $175 million. The works are predominantly in New South Wales and so TransGrid is the proponent of Option 1A.

Delivery and completion of inter-network testing is expected by June 2022. TransGrid is working with the New South Wales Government, as part of its NSW Transmission Infrastructure Strategy, on a range of initiatives to support early development of the preferred near-term option by bringing forward early planning and feasibility work.

# Appendix A Checklist of compliance clauses

This section sets out a compliance checklist which demonstrates the compliance of this PADR with the requirements of clause 5.16.4(b) of the National Electricity Rules version 124.

| Rules clause | Summary of requirements | Relevant section(s) in the **PADR** |
|---|---|---|
| 5.16.4(k) | A RIT-T proponent must prepare a report (the assessment draft report), which must include: | - |
| | (1) a description of each credible option assessed; | 5 |
| | (2) a summary of, and commentary on, the submissions to the project specification consultation report; | 4 & Appendix C |
| | (3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option; | 8 |
| | (4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost; | 7 |
| | (5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material; | 7.4 |
| | (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); | 8 |
| | (7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results; | 8 |
| | (8) the identification of the proposed preferred option; | 8 & 9 |
| | (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. | 9 |

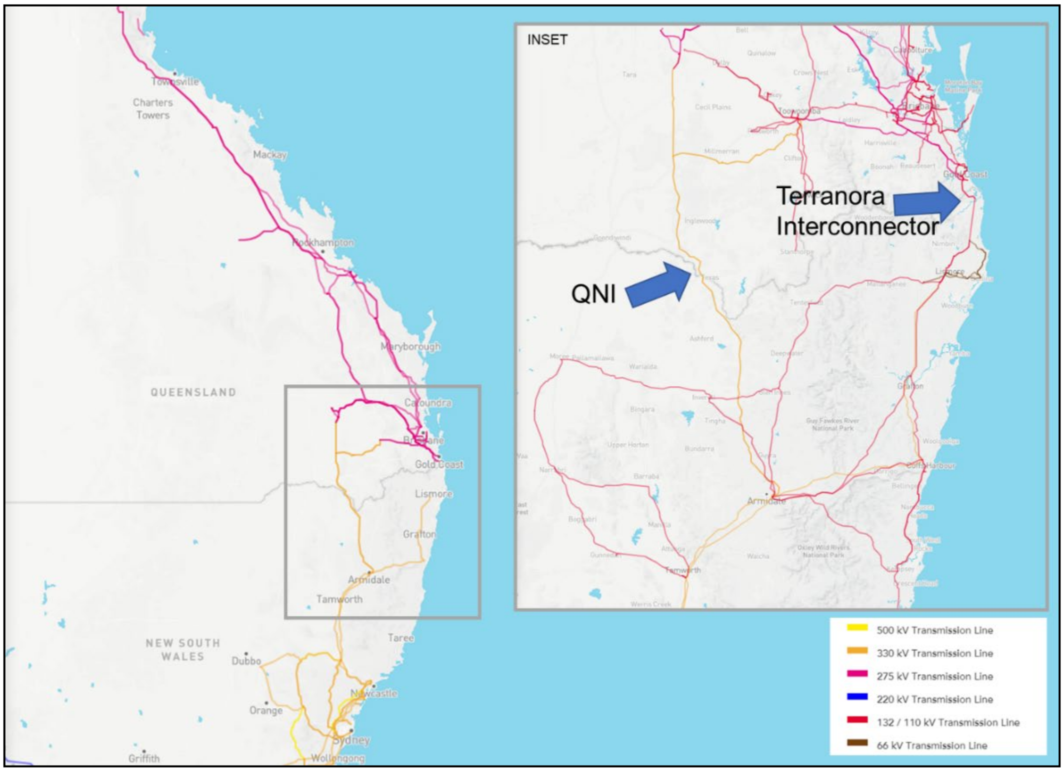
# Appendix B Current interconnection between New South Wales and Queensland

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

- Queensland to New South Wales Interconnector (QNI) – a high voltage alternating current (HVAC) 330kV transmission line connecting two power systems with a nominal transfer capacity of 310 MW from New South Wales to Queensland ('northwards') and 1,025 MW from Queensland to New South Wales ('southwards').[88] QNI is operated under a joint operating agreement between TransGrid and Powerlink.
- Terranora Interconnector – a high voltage alternating current (HVAC) 110kV double circuit between Mudgeeraba substation in Queensland and Terranora substation in NSW. Terranora is connected to the rest of the New South Wales network through high voltage direct current (HVDC) transmission lines referred to as Directlink. Directlink has three pairs of bipolar transmission cables with a capacity to deliver a maximum of 180 MW in either direction. Directlink is operated by the APA Group.

The existing transmission networks in northern New South Wales and southern Queensland are shown in Figure 24, with the two existing interconnectors between the states highlighted.

**Figure 24 – 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*](https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Interactive-maps-and-dashboards)

Figure 25 shows a one-line diagram of the relevant transmission network in northern New South Wales and southern Queensland. It includes line names that are referenced throughout this report.

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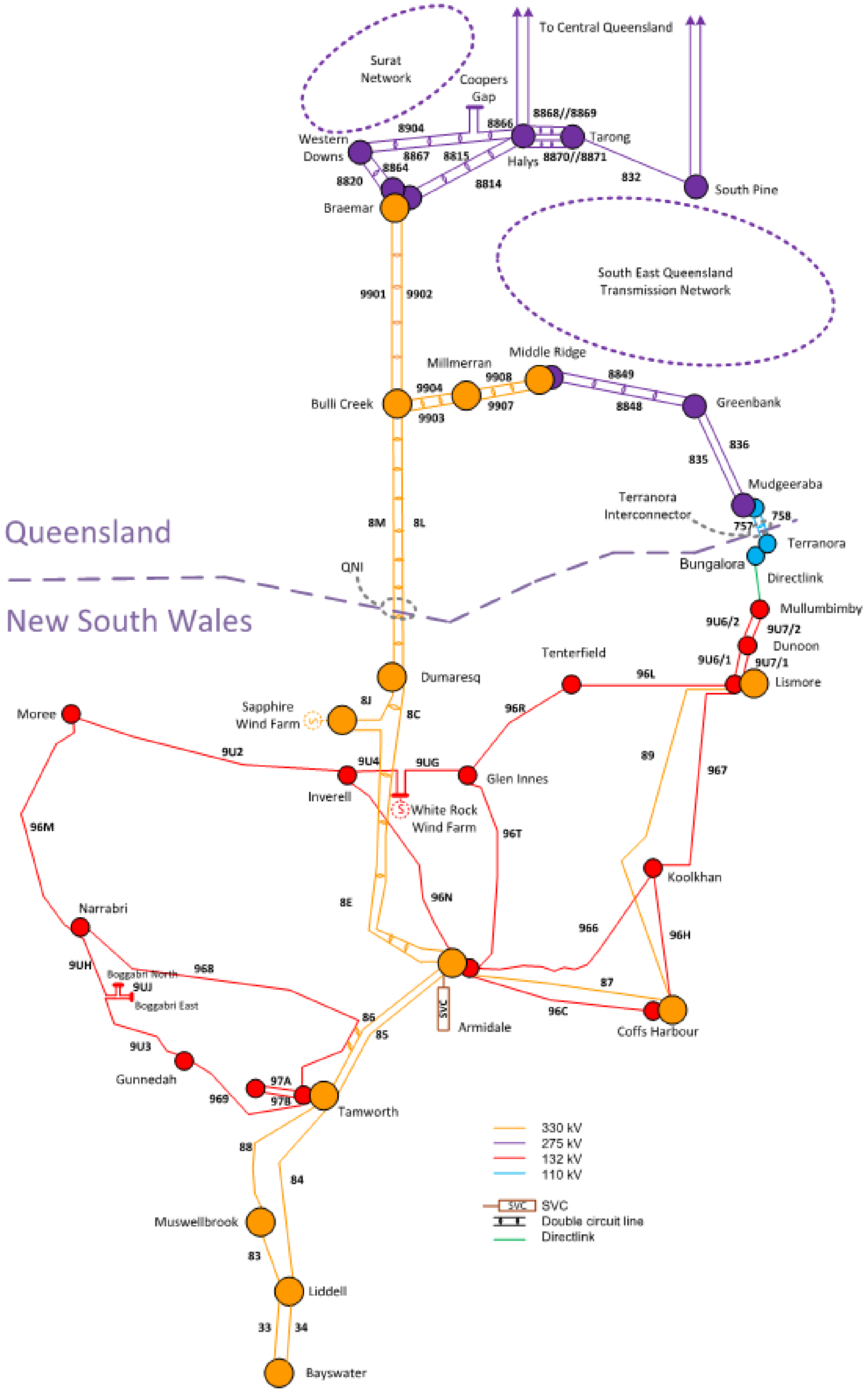
[88] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/2018-Integrated-System-Plan--Modelling-Assumptions.xlsx

Figure 25 – Specific transmission lines in northern New South Wales and southern Queensland



# Appendix C 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 this 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 6 – 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. | This 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 this PADR provide detailed descriptions of the key modelling assumption and approaches adopted, while section 8 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 this 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. |
| 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 eight and 30 as contained in the PSCR. | ERM Power, p 1. | Appendix D 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. |
| *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 this 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.<br>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. |
| The PSCR indicates that a discount rate of 4.6 per cent will be used and a higher rate seems more appropriate. | EnergyAustralia, p 2. | Addressed in section 4.6. |
| Modelling should not only test the timing of any new network investment but the size and whether it is constructed. | EnergyAustralia, p 2. | Addressed in section 4.6. |
| 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 this 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. |
| 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. | The anticipated rule changes are still pending. 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). |

| | | |
|---|---|---|
| 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. |
| 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 above) is consistent with staging the investment. That is, this 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. |
| 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. |
| 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 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). |

| | | |
|---|---|---|
| *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. |
| 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 this PADR are discussed in sections 6.1 and 6.3, 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.<br>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.<br>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 |

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| | | 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) 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.<br>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. |
| The RIT-T should consider the impact on the availability of hedging contracts in the NEM. | EnergyAustralia, p 3. | Addressed in section 4.7. |
| 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. |
| ***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. |
| 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. |
| *Near-term options for increasing transfer capacity* | | |

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| 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 this 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 can only publish the generic battery cost for both Option 5A and Option 5B. |
| Option 1B and Option 1C in the PSCR are not adequate, even as a first step. | WalchaEnergy, p 12. | Addressed in section 4.3. |
| 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. |
| 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. |
| *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. | |

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| 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. |

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| 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 D Technical analysis and expected limit improvements for each option

This appendix presents a summary of the results of detailed power system studies performed on each of the credible options since the PSCR was released and provides greater detail on the modelled changes to transfer capacities, across a range of representative operating conditions.

## D.1 Option 1A – Uprate Liddell to Tamworth lines and install dynamic and static reactive support

For northerly power transfers, thermal limitations may occur on the Liddell – Tamworth 330 kV line following the loss of the Liddell – Muswellbrook 330 kV line. Uprating of these lines increases the thermal capability by approximately 170MW. Although the uprating is initially beneficial for northerly transfers only, it becomes increasingly important for southerly transfers with generator expansion in the Northern New South Wales zone.

The addition of new SVCs at Tamworth and Dumaresq increases the level of dynamic reactive reserves and therefore improves the northward and southward stability limits. Combined with static capacitors, the improved stability limit would often exceed the thermal capability.

System normal transmission limits on QNI are sensitive to a number of variables, including:

- demand levels;
- time of day (predominantly affecting dispatch and thermal ratings);
- time of year (predominantly affecting thermal ratings);
- the generation level of the largest generating unit in Queensland;
- the generation level of Sapphire Wind Farm (WF); and
- Northern NSW generation including Directlink transfer.

There is a complex interplay between generation and load which can result in different modes of failure and critical contingencies for different operating conditions. Under Option 1A, critical contingencies setting northerly limits include the trip of Liddell – Muswellbrook 330kV (overloading Liddell – Tamworth 330kV) and the trip of a large generator in Queensland. Southerly transfers are limited by contingency on Bulli Creek – Dumaresq 330kV, Sapphire – Armidale 330kV or Armidale – Tamworth 330kV feeders or a Braemar 330/275kV transformer. Depending on the location and generation of new entrants, the Muswellbrook – Liddell 330kV and Tamworth – Liddell 330kV become critical contingencies for southerly transfers.

Table 7 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 7 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 8 lists corresponding notional planning level winter limits for Option 1A.

**Table 8 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 |

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|---|---|---|---|---|---|
| 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 |

## D.2 Option 1B – Uprate Liddell to Tamworth lines

This option examines the benefit of the line uprate component of Option 1A. Without addressing the stability limitations, transfers following the implementation of this option would initially be predominantly limited by stability. Although the uprating is initially beneficial for northerly transfers only, it becomes increasingly important for southerly transfers with generator expansion in the Northern New South Wales zone.

Under Option 1B, critical contingencies setting northerly limits include a trip of Liddell – Muswellbrook 330kV (overloading Liddell – Tamworth 330kV) and the trip of a large generator in Queensland. Southerly transfers are limited by contingency on Dumaresq – Sapphire 330kV, Sapphire – Armidale 330kV or Armidale – Tamworth 330kV feeders. Depending on the location and generation of new entrants, the Muswellbrook – Liddell 330kV and Tamworth – Liddell 330kV become critical contingencies for southerly transfers.

Table 9 lists notional planning level summer limits, mode of failure and limit improvements provided by Option 1B 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 9 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 |

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|---|---|---|---|---|---|
| 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 10 lists corresponding notional planning level winter limits for Option 1B.

**Table 10 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 |
| | Day Medium | 570 (Stability) | 1,070 (Stability) | 0 | 0 |
| | Day Low | 670 (Stability) | 1,030 (Thermal) | 0 | 0 |
| | Night High | 560 (Thermal) | 1,000 (Stability) | 195 | 0 |
| | Night Medium | 560 (Stability) | 990 (Stability) | 15 | 0 |
| | Night Low | 635 (Stability) | 985 (Stability) | 0 | 0 |
| Low Sapphire | Day High | 410 (Stability) | 1,215 (Stability) | 165 | 0 |
| | Day Medium | 375 (Stability) | 1,205 (Stability) | 0 | 0 |
| | Day Low | 525 (Stability) | 1,200 (Thermal) | 0 | 0 |
| | Night High | 305 (Stability) | 1,225 (Stability) | 195 | 0 |
| | Night Medium | 365 (Stability) | 1,215 (Stability) | 80 | 0 |
| | Night Low | 445 (Stability) | 1,210 (Stability) | 0 | 0 |

## D.3 Option 1C – Install dynamic and static reactive support

This option examines the benefit of the reactive support component of Option 1A. Without addressing the thermal limitations, transfers following the implementation of this option would predominantly be limited by thermal ratings.

Under Option 1C, critical contingencies setting northerly limits include a trip of Liddell – Muswellbrook 330kV (overloading Liddell – Tamworth 330kV) and the trip of a large generator in Queensland. Southerly transfers are limited by contingency on Bulli Creek – Dumaresq 330kV, Sapphire – Armidale 330kV or Armidale – Tamworth 330kV feeders or a Braemar 330/275kV transformer. Depending on the location and generation of new entrants, the Muswellbrook – Liddell 330kV and Tamworth – Liddell 330kV become critical contingencies for southerly transfers.

Table 11 lists notional planning level summer limits, mode of failure and limit improvements provided by Option 1C 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 11 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 12 lists corresponding notional planning level winter limits for Option 1C.

**Table 12 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 Sapphire | 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 |

## D.4 Option 1D – Cutting in the Sapphire substation to Line 8C and constructing a new switching station

This option examines an alternative method for increasing stability limits and is best compared with Option 1C. In Option 1D, stability limits are increased by targeting the southerly stability limit critical contingencies by cutting in Dumaresq – Armidale 330kV into the existing Sapphire 330kV substation and establishing a new mid-point substation between Bulli Creek and Dumaresq 330kV substations to switch the long Bulli Creek – Dumaresq 330kV lines. Without addressing the thermal limitations, transfers following the implementation of this option would predominantly be limited by thermal ratings.

Under Option 1D, critical contingencies setting northerly limits include a trip of Liddell – Muswellbrook 330kV (overloading Liddell – Tamworth 330kV) and the trip of a large generator in Queensland. Southerly transfers are limited by contingency Sapphire – Armidale 330kV or Armidale – Tamworth 330kV feeders or the loss of a large load in Queensland (the largest Boyne Island potline). Depending on the location and generation of new entrants, the Muswellbrook – Liddell 330kV and Tamworth – Liddell 330kV become critical contingencies for southerly transfers.

Table 13 lists notional planning level summer limits, mode of failure and limit improvements provided by Option 1D 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 13 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 14 lists corresponding notional planning level winter limits for Option 1D.

**Table 14 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 |

## D.5 Option 5A – Small-scale BESS (2 x 40MW/20MWh)

This option introduces a novel concept using a pair of batteries as a virtual transmission line. By combining with a System Integrity Protection Scheme (SIPS) that detects otherwise critical contingencies and quickly deploying appropriate control actions, the batteries will charge or discharge to dampen the effect of the disturbance. For example, to extend the southerly QNI limit immediately following the loss of a Sapphire – Armidale 330kV circuit, the battery to the north of Dumaresq would be sent a charge action and the pair to the south of Armidale a discharge action. The combination of actions results in unloading this southerly flow by the capacity of the battery (40MW). If this is performed quickly, stability and thermal limits set by post-contingent conditions can all be extended by approximately the size of the level of unloading.

Following a contingency event, clause 4.2.6 of the NER allows AEMO a maximum of 30 minutes to return the power system to a secure operating state. In order to preserve the 30 minutes, this option could involve:

- 2 x 40MW/40MWh batteries maintained at half charge. When called upon (post-contingency), they have the capacity for 30 minutes of 40MW support.
- 2 x 40MW/20MWh batteries
  - One battery kept at full charge, the other fully discharged to provide a limit improvement in the direction pointing to the fully charged battery.
  - Operationally cycling the charge state to improve both northerly and southerly limits as required

Once operated the limit extension/s will once again become available when the batteries are returned to their initial state. Details of how the battery operating charge state is achieved, which would impact power flows between the batteries, would need to be determined.

For the purposes of this PADR, we have assumed cycling operation to improve both northerly and southerly limits. Proponents informed that battery cycling reduces battery life and increases O&M costs. This option assumes a technical life of 15 years and an opex cost of 1% of the initial capital cost.

In increasing the limit from existing levels, new contingencies may become critical and would need to be incorporated into the SIPS to allow further increases in the limit.

An advantage of this option is that, unlike transmission lines, the cost of the installation of the batteries is not dependent on the distance between the batteries. The batteries and SIPS can therefore be configured to address multiple congestions by incorporating more triggering events into the SIPS. For the purposes of this RIT-T, the northern battery has been located at Calvale to extend the central Queensland to south Queensland (CQSQ) limit and provide additional market benefits.

Although services provided by batteries are typically stacked, this application relies on the pair of batteries not being operated before the contingency when the extended limit is required. This requirement therefore limits the functionality it can exercise in providing other services, e.g. in the energy market.

Table 15 lists notional planning level summer limits, mode of failure and limit improvements provided by Option 5A 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 15 Notional QNI limits and limit improvements following Option 5A – 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 | 405 (Thermal) | 1,110 (Stability) | 40 | 40 |
| | Day Medium | 520 (Thermal) | 1,110 (Stability) | 40 | 40 |
| | Day Low | 710 (Stability) | 990 (Thermal) | 40 | 40 |
| | Night High | 370 (Thermal) | 1,040 (Stability) | 40 | 40 |
| | Night Medium | 515 (Thermal) | 1,030 (Stability) | 40 | 40 |
| | Night Low | 675 (Stability) | 1,025 (Stability) | 40 | 40 |
| Low Sapphire | Day High | 230 (Thermal) | 1,255 (Stability) | 40 | 40 |
| | Day Medium | 340 (Thermal) | 1,245 (Stability) | 40 | 40 |
| | Day Low | 565 (Stability) | 1,170 (Thermal) | 40 | 40 |
| | Night High | 110 (Thermal) | 1,265 (Stability) | 40 | 40 |
| | Night Medium | 260 (Thermal) | 1,255 (Stability) | 40 | 40 |
| | Night Low | 485 (Stability) | 1,250 (Stability) | 40 | 40 |

Table 16 lists corresponding notional planning level winter limits for Option 5A.

**Table 16 Notional QNI limits and limit improvements following Option 5A – 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 | 465 (Thermal) | 1,110 (Stability) | 40 | 40 |
| | Day Medium | 610 (Thermal) | 1,110 (Stability) | 40 | 40 |
| | Day Low | 710 (Stability) | 1,070 (Thermal) | 40 | 40 |
| | Night High | 405 (Thermal) | 1,040 (Stability) | 40 | 40 |
| | Night Medium | 585 (Thermal) | 1,030 (Stability) | 40 | 40 |
| | Night Low | 675 (Stability) | 1,025 (Stability) | 40 | 40 |
| Low Sapphire | Day High | 285 (Thermal) | 1,255 (Stability) | 40 | 40 |
| | Day Medium | 415 (Stability) | 1,245 (Stability) | 40 | 40 |
| | Day Low | 565 (Stability) | 1,240 (Thermal) | 40 | 40 |
| | Night High | 150 (Thermal) | 1,265 (Stability) | 40 | 40 |
| | Night Medium | 325 (Thermal) | 1,255 (Stability) | 40 | 40 |
| | Night Low | 485 (Stability) | 1,250 (Stability) | 40 | 40 |

## D.6 Option 5B – Larger-scale BESS (2 x 200MW/100MWh)

This option introduces is a larger alternative to Option 5A. The discussion in D.5 regarding clause 4.2.6 of the NER and assumed cycling operation for the PADR modelling also apply to Option 5B.

Table 17 lists notional planning level summer limits, mode of failure and limit improvements provided by Option 5B 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 17 Notional QNI limits and limit improvements following Option 5B – 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 | 565 (Thermal) | 1,270 (Stability) | 200 | 200 |
| | Day Medium | 680 (Thermal) | 1,270 (Stability) | 200 | 200 |
| | Day Low | 870 (Stability) | 1,150 (Thermal) | 200 | 200 |
| | Night High | 530 (Thermal) | 1,200 (Stability) | 200 | 200 |
| | Night Medium | 675 (Thermal) | 1,190 (Stability) | 200 | 200 |
| | Night Low | 835 (Stability) | 1,185 (Stability) | 200 | 200 |
| Low Sapphire | Day High | 390 (Thermal) | 1,415 (Stability) | 200 | 200 |
| | Day Medium | 500 (Thermal) | 1,405 (Stability) | 200 | 200 |
| | Day Low | 725 (Stability) | 1,330 (Thermal) | 200 | 200 |
| | Night High | 270 (Thermal) | 1,425 (Stability) | 200 | 200 |
| | Night Medium | 420 (Thermal) | 1,415 (Stability) | 200 | 200 |
| | Night Low | 645 (Stability) | 1,410 (Stability) | 200 | 200 |

Table 18 lists corresponding notional planning level winter limits for Option 5B.

Table 18 Notional QNI limits and limit improvements following Option 5B – 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 | 625 (Thermal) | 1,270 (Stability) | 200 | 200 |
| | Day Medium | 770 (Stability) | 1,270 (Stability) | 200 | 200 |
| | Day Low | 870 (Stability) | 1,230 (Thermal) | 200 | 200 |
| | Night High | 565 (Thermal) | 1,200 (Stability) | 200 | 200 |
| | Night Medium | 745 (Thermal) | 1,190 (Stability) | 200 | 200 |
| | Night Low | 835 (Stability) | 1,185 (Stability) | 200 | 200 |
| Low Sapphire | Day High | 445 (Thermal) | 1,415 (Stability) | 200 | 200 |
| | Day Medium | 575 (Thermal) | 1,405 (Stability) | 200 | 200 |
| | Day Low | 725 (Stability) | 1,400 (Thermal) | 200 | 200 |
| | Night High | 310 (Thermal) | 1,425 (Stability) | 200 | 200 |
| | Night Medium | 485 (Thermal) | 1,415 (Stability) | 200 | 200 |
| | Night Low | 645 (Stability) | 1,410 (Stability) | 200 | 200 |