TransGrid

Improving stability in south-western NSW

RIT-T – Project Assessment Draft Report

Region: South Western New South Wales

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Executive summary

TransGrid is applying the Regulatory Investment Test for Transmission (RIT-T) to options for improving stability in the south-western New South Wales (NSW) power system. Publication of this Project Assessment Draft Report (PADR) represents the second step in the RIT-T process and follows the Project Specification Consultation Report (PSCR) released in July 2020.

Benefits from the options considered in this PADR

The main power system in south-western NSW consists primarily of one 330 kV transmission line from Darlington Point to Wagga Wagga (Line 63) and 220 kV transmission lines west of Darlington Point (including Line X5). Smaller underlying 132 kV transmission lines supply regional towns.

This area has seen significant growth in renewable generation connections to the transmission network as part of the wider energy market transition. Approximately 594 MW of renewable generation has connected in the area since December 2015 and approximately 695 MW of renewable generation is currently being commissioned. This is having an impact on how this part of the power system operates. In particular, while power has historically primarily flowed west from Darlington Point to supply rural and mine loads, this is expected to reverse with the increase in renewable generation in the area, particularly during daytime when there is an abundance of solar generation.

These changes in power flows are expected to lead to an increasing risk of power system instability going forward. Currently the only way of managing this risk is to constrain generation in south-western NSW. In recognition of the risks to future power system stability, in May 2020 the Australian Energy Market Operator (AEMO) implemented an operational constraint in the NEM Dispatch Engine to limit power flows and prevent this occurring.

TransGrid has identified the opportunity to strengthen the transmission network to relieve this constraint and provide wider market benefits to the National Electricity Market (NEM). Specifically, the market modelling undertaken as part of this PADR finds that there are significant benefits expected from options that relieve the constraint in terms of avoided generator dispatch cost, avoided and deferred capital costs associated with new generation and storage capacity and lower transmission costs associated with connecting Renewable Energy Zones (REZ). This PADR compares these benefits to the costs of the various investment options.

TransGrid recognises that the need to introduce constraints in the transmission system in south-western NSW has had a material impact on the operation of renewable generation that has recently connected in that area. TransGrid is committed to completing this RIT-T process in a timely fashion, to enable investment to relieve this constraint, where that is found to be net beneficial to the market.

The PADR analysis has benefited from stakeholder consultation

The PSCR was released in July 2020 and TransGrid subsequently received submissions from seven parties, which can be grouped into the following two broad categories:

> existing or new renewable generators in south-western NSW – Sunraysia, Neoen, RWE, Reach Solar Energy;

> one solar generator– whom requested that their submission be kept confidential; and

> two providers of battery systems – both of whom have requested that their submissions be kept confidential.

While submissions covered a range of topics, there were five broad topics that were most commented on, namely:

> support for the identified need;

> whether the construction timetable of the new/rebuild line options is realistic;
> the ability of interim solutions to assist in the near term;
> a potential grid-connected battery option; and
> whether a stand-alone STATCOM is a technically feasible solution.

Each of the points raised in submissions have been summarised and responded to in this PADR.

In addition, prior to, as well as after, receiving submissions, TransGrid held a number of bilateral meetings with submitters in order for them to further understand the RIT-T assessment and the option requirements in south-western NSW, as well as how proposed solutions are expected to be able to assist with meeting the identified need. These discussions have played a pivotal role in being able to define and include the credible options assessed in this PADR and TransGrid thanks all parties for their time and effort to-date.

For more information on the RIT-T process including various opportunities for stakeholders to provide submissions and feedback please see Appendix E 'The RIT-T Process explained'.

Five types of credible options have been developed and assessed in this PADR

Stakeholder consultation on the PSCR has assisted with developing and refining the credible options put forward in the PSCR. Specifically, consultation with third parties since the PSCR has enabled this PADR to assess the following five types of credible options:

> Option 1 – a new or rebuilt 330 kV transmission line between Darlington Point and the new Dinawan substation being constructed for EnergyConnect:
  – Option 1A (new line);
  – Option 1B (rebuilt line);
> Option 2 – a new 330 kV transmission line between Darlington Point and the Wagga Wagga substation;
> Option 3 – a static synchronous compensator (STATCOM) solution at the Darlington Point substation;
> Option 4 – Option 1A plus an interim 3-year battery solution; and
> Option 5 – a standalone long-term battery solution.

Table E-1 below summarises each of the credible options.

Table E-1: Summary of the credible options

Option	Description	Estimated capital cost	Expected delivery time
1A	Establish a new Darlington Point to Dinawan 330 kV transmission line	$211 million	4-5 years
1B	Rebuild the existing 99T Darlington Point to Coleambally and 99L Coleambally to Deniliquin as 330 kV to Dinawan	$303 million	4-5 years
2	Establish a new Wagga Wagga to Darlington Point 330 kV transmission line	$393 million	4-5 years
3	STATCOM	$50 million for a 100 MVar STATCOM	3-4 years
4	Option 1A + 3-year interim network support solution utilising a battery (proposed by a confidential submitter)	$211 million (for the network component)	4-5 years for the network component

Option	Description	Estimated capital cost	Expected delivery time
		Confidential for network support	Network support from battery available from Q1 2022
5	A standalone long-term battery solution (proposed by a confidential submitter)	Confidential	2022/23 commissioning

Establishing a new Darlington Point to Dinawan 330 kV transmission line provides the greatest net benefits of all options considered

Uncertainty is captured under the RIT-T framework through the use of scenarios, which reflect different assumptions that are expected to affect the key drivers of the estimated net market benefits.

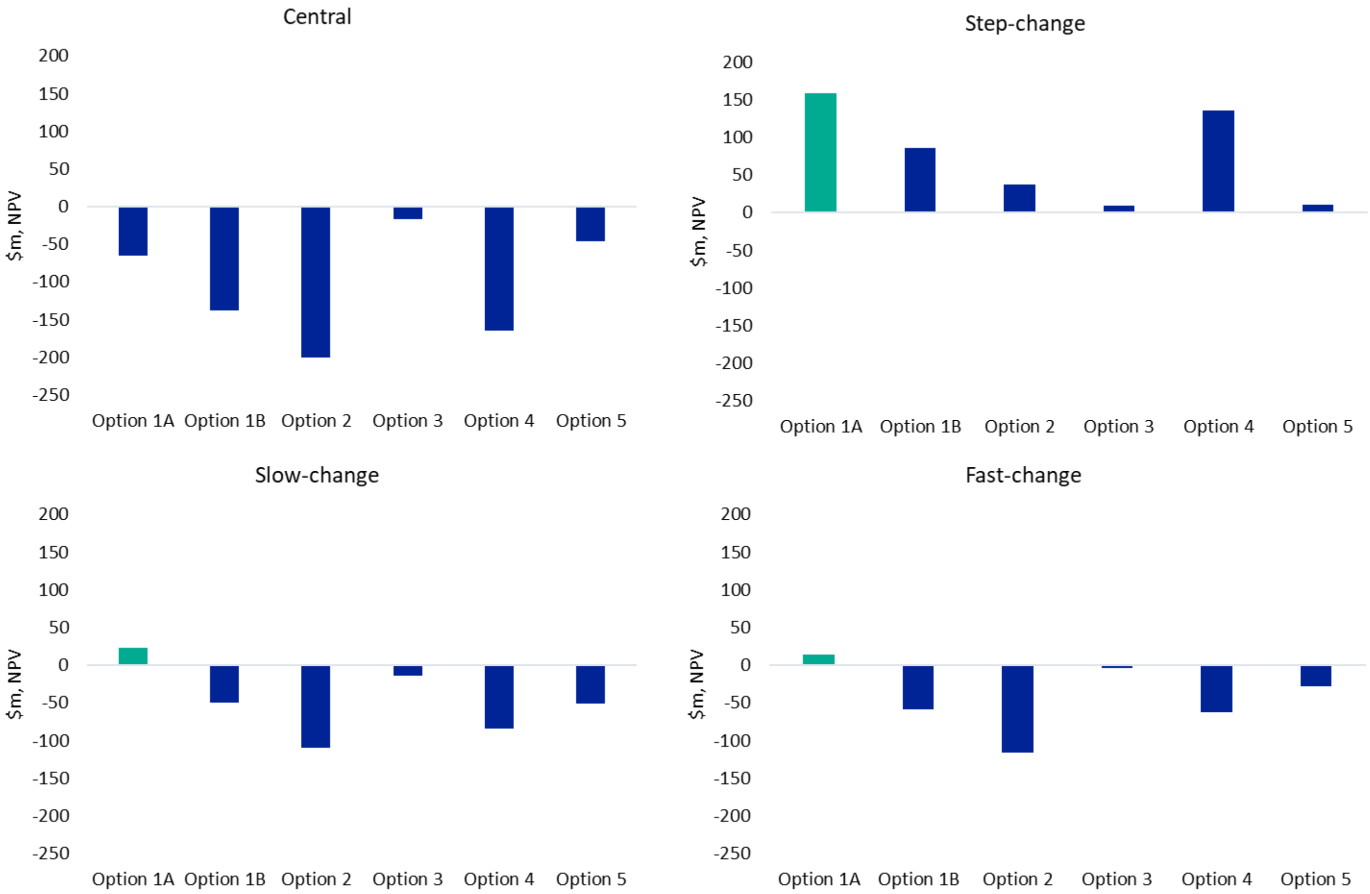
Four core scenarios have been considered as part of this PADR, which are intended to cover a wide range of possible futures and are generally aligned with the AEMO 2020 ISP 'central', 'slow-change', 'step-change' and 'fast-change' scenarios. The four scenarios differ in relation to key variables expected to affect the market benefits of the options considered, including demand outlook, the uptake of Distributed Energy Resources (DER), 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 (a new Darlington Point to Dinawan 330 kV transmission line) is the only option with positive expected net benefits on an weighted basis across all scenarios. Option 1A is expected to deliver net benefits of $33 million on a weighted basis, with the second ranked option, Option 3 (STATCOM), having an estimated net cost of approximately $7 million. Overall, the PADR analysis finds that Option 1A is the preferred option for this RIT-T.

Option 1A is found to deliver positive net benefits in three of the four scenarios, with the step-change scenario expected to provide significant net benefits (in the order of $160 million). TransGrid notes that recent commentary from the Energy Security Board (ESB) suggests that the NEM is in fact tracking closest to the step-change currently[1] and that the net benefits of Option 1A increase to nearly $60 million if the step-change scenario is given a weighting of 40 per cent (with the other three scenarios weighted equally) in the analysis.

[1] See Argus Media, Australia tops step-change energy transition scenario, Morrison, K., 7 May 2021 (accessed via https://www.argusmedia.com/en/news/2212777-australia-tops-stepchange-energy-transition-scenario on 7 July 2021) , Renew Economy, *"We are headed for step change:" ESB's Kerry Schott on new market design,* Parkinson, G., 30 September 2020 (accessed via https://reneweconomy.com.au/we-are-headed-for-step-change-esbs-kerry-schott-on-new-market-design-89487/ on 7 July 2021) & ESB, *The Health of the National Electricity Market 2020*, Volume 1: The ESB Health of the NEM Report, 5 January 2020, p. 8.

Figure E-1: Summary of the estimated net benefits



The market benefits of all options are primarily derived from avoided generator dispatch cost, avoided and deferred capital costs associated with new generation and storage capacity and lower transmission costs associated with connecting REZ (under the step-change scenario). On a weighted basis, these three categories of market benefit make up nearly all of the total market benefits estimated for Option 1A.

The market modelling undertaken finds that the assumed timing of VNI West and the assumptions regarding the carbon budget have the strongest impact on the estimated benefits for the options. Specifically:

> with VNI West in-place, the transfer limit between south-western NSW and Wagga Wagga (Canberra zone) is 3,000 MW under both the base case and option cases (meaning that benefits are limited to the years prior to VNI West being commissioned); and

> with the carbon budget, there is a requirement for lower coal generation and higher renewable build, which results in a greater estimated benefits for any options that unlock cheaper renewable resources.

The modelling therefore finds that the step-change scenario has significantly greater market benefits than the other scenarios since VNI West is assumed to be commissioned in 2035 under this scenario, along with a very restrictive carbon budget. Moreover:

> the central scenario is found to have the lowest net benefits of all scenarios since there are only a few years that the options provide benefits before VNI West is commissioned (in 2028/29 for this scenario);[2]

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2 We have assumed an earlier commissioning date for VNI West under the central scenario than in the core 2020 ISP assumptions, consistent with AEMO's accelerated delivery date in the 2020 ISP (and the draft 2021 IASR timing). Specifically, we have assumed a timing of 2028/29 for VNI West under the central scenario. While AEMO has an accelerated delivery date of 2027/28 for VNI West in the 2020 ISP (and draft 2021 IASR), we have assumed a commissioning of 1 July 2028 as this is our current view of the earliest practical delivery date.

> the fast-change scenario has a VNI West timing of 2035/36 and a restricted carbon budget that results in higher benefits for this scenario compared to the central scenario; and

> while VNI West is excluded in the slow change scenario, the other key assumptions in this scenario (such as a significantly lower demand forecasts and coal life extension) are expected to result in lower new capacity requirements that, on balance, lead to similar net benefits for the options compared to the fast-change scenario.

TransGrid notes that it is intended that the analysis in the PACR will be updated to reflect the final 2021 Inputs, Assumptions and Scenarios Report (IASR) that was recently published by AEMO, as well as any other recent relevant market developments not captured in these assumptions.

Next steps

TransGrid welcomes written submissions on this PADR. Submissions are due on 5 November 2021[3].

Submissions should be emailed to TransGrid's Regulation team via regulatory.consultation@transgrid.com.au.[4] In the subject field, please reference 'PADR Improving stability in south-western NSW project.'

At the conclusion of the consultation process, all submissions received will be published on TransGrid's website. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement.

The next formal stage of this RIT-T is the publication of a PACR. The PACR is expected to be published by early 2022.

[3] Additional days have been added to cover public holidays.

[4] TransGrid is bound by the Privacy Act 1988 (Cth). In making submissions in response to this consultation process, TransGrid will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement.

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1. Introduction

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The main power system in south-western NSW consists primarily of one 330 kV transmission line from Darlington Point to Wagga Wagga (Line 63) and 220 kV transmission lines west of Darlington Point (including Line X5). Smaller underlying 132 kV transmission lines supply regional towns.

This area has seen significant growth in renewable connections to the transmission network as part of the wider energy market transition. Approximately 594 MW of renewable generation has connected in the area since December 2015 and approximately 695 MW of renewable generation is currently being commissioned. This is having an impact on how this part of the power system operates. In particular, while power has historically primarily flowed west from Darlington Point to supply rural and mine loads, this is expected to reverse with the increase in renewable generation in the area, particularly during daytime when there is an abundance of solar generation.

These changes in power flows are expected to lead to an increasing risk of power system instability going forward. Currently the only way of managing this risk is to constrain generation in south-western NSW. In recognition of the risks to future power system stability, in May 2020 the Australian Energy Market Operator (AEMO) implemented an operational constraint in the NEM Dispatch Engine (NEMDE) to limit power flows and prevent this occurring.[5]

TransGrid has identified the opportunity to strengthen the transmission network to relieve this constraint and provide market benefits to the National Electricity Market (NEM). This RIT-T has therefore been initiated to progress and consult on the assessment of investment options and whether the market benefits outweigh the costs of the investments. The investments considered in this RIT-T did not form part of AEMO's final 2020 Integrated System Plan (ISP), and so are being progressed outside of the ISP framework.

TransGrid's revenue determination for the 2018-2023 regulatory control period includes a contingent project for providing stability in south-west NSW ('the Support South Western NSW for Renewables' contingent project). This contingent project is to reinforce the transmission network in the area to enable additional renewable generation and provide net market benefits to NSW as well as the wider NEM. One of the trigger events for the contingent project is successful completion of a RIT-T.[6]

The findings of this PADR align with the NSW Electricity Infrastructure Roadmap,[7] which was legislated in December 2020, and will allow for more renewable energy to be dispatched into the NEM from the proposed South West NSW REZ.

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5 TransGrid notes that while AEMO implemented a further system normal constraint regarding voltage collapse in south-western NSW on 20 November 2020, this constraint is not relevant to the identified need for this RIT-T. Specifically, the new voltage limit announced will impose a flow limitation from Balranald to Darlington Point of 150 MW and is expected to be significantly alleviated following commissioning of EnergyConnect in 2024-25. See: https://www.aemo.com.au/market-notices?marketNoticeQuery=&marketNoticeFacets=RECALL+GEN+CAPACITY%2CCONSTRAINTS

6 AER, *FINAL DECISION TransGrid transmission determination 2018 to 2023*, Attachment 6 – Capital expenditure, May 2018, pp. 138-139 – available at: https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20TransGrid%20transmission%20determination%20-%20Attachment%206%20-%20Capital%20expenditure%20-%20May%202018_0.pdf

7 https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap

1.1 Purpose

The purpose of this PADR is to:

> identify and confirm the market benefits expected from the various options for improving the stability of the south-western NSW power system;
> summarise points raised in submissions to the PSCR and highlight how these have been addressed in the RIT-T analysis;
> describe the options being assessed under this RIT-T, including how these have been shaped as part of the PSCR consultation and the additional options proposed in submissions;
> present the results of the NPV analysis for each of the credible options assessed;
> describe the key drivers of these results, and the assessment that has been undertaken to ensure the robustness of the conclusion; and
> identify the preferred option at this stage of the RIT-T, i.e., the option that is expected to maximise net market benefits.

Overall, this report provides transparency into the planning considerations for investment options to stabilise the south-western NSW power system, and the associated market benefits. 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.

1.2 How to make a submission and next steps

TransGrid welcomes written submissions on this PADR. Submissions are due on 5 November 2021[8].

Submissions should be emailed to TransGrid's Regulation team via regulatory.consultation@transgrid.com.au.[9] In the subject field, please reference 'PADR Improving stability in south-western NSW project.'

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TransGrid recognises that the need to introduce constraints in the transmission system in south-western NSW has had a material impact on the operation of renewable generation that has recently connected in that area and are committed to completing this RIT-T process in a timely fashion.

8 Additional days have been added to cover public holidays.

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2. Benefits from improving the stability of the south-western NSW power system

This section outlines the key benefits expected from the various options assessed in this PADR for improving the stability of the south-western NSW power system. It first re-summarises the 'identified need' for this RIT-T from the PSCR and how AEMO has needed to impose a new system normal constraint to limit flows in the area.

More information on the current network and forecast generation connections in the area is provided in Appendix B.

2.1 Summary of the 'identified need'

The power system in the NEM must be planned and operated to remain stable during an outage of any single transmission line. Schedule 5.1 of the National Electricity Rules (NER) sets out the default planning, design and operating criteria that must be applied by all TNSPs in operating their networks and includes minimum standards for network stability.

Our system studies have highlighted that the 132 kV system in south-western NSW can experience significant stability issues during an outage of Line 63, including thermal overloads and under-voltage. These are particularly likely during high power flows west to Wagga Wagga and are currently managed operationally through measures such as:

> power flow constraints;
> transfer tripping Line X5 for a trip of Line 63; and
> splitting 132kV parallels to Line 63 pre-contingency.

Approximately 594 MW of renewable generation has connected in the area since December 2015 and approximately 695 MW of renewable generation is currently being commissioned.[10] The commissioning of new generation west of Darlington Point resulted in high power flows east towards Wagga Wagga from mid-2020. Under these conditions, the 132 kV system would experience even more significant stability issues during an outage of Line 63, including fast voltage collapse, thermal overloads and under-voltage. There is a particular risk of fast voltage collapse that would result in power electronics based renewable generation becoming unstable and result in further cascading generator outages and further stability issues.

New measures are therefore required to maintain power system stability during high easterly power flows. Considering the very fast timeframe of voltage collapse, the only feasible operational solution identified in the short term is a pre-contingent constraint to limit power flows east from Darlington Point to Wagga Wagga.

Based on our advice, on 8 May 2020, AEMO implemented a new system normal constraint in the NEM dispatch engine (NEMDE) to limit power flows on Line 63. This constraint has been developed to minimise the risk of voltage collapse at Darlington Point and the constraint equation includes generators in south-west NSW and north-west Victoria as well as Murraylink.[11] The existing operational measures outlined above for when there are high power flows west are not able to be expanded to resolve the voltage collapse issues when there are high easterly flows.

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[10] Appendix B summarises the recent and anticipated renewable generation connections in south-western NSW.

[11] https://aemo.com.au/market-notices/?marketNoticeQuery=&marketNoticeFacets=SYSTEM+RECONFIGURATION%2cCONSTRAINTS%2cINTER-REGIONAL+TRANSFER%2cPROTECTED+EVENT%2cLOR2+ACTUAL&MarketNoticeList=5

The limit for power flows east is approximately 300 MW, although it will vary slightly with power system conditions. With new renewable generators continuing to be commissioned in south-western NSW, the power flow is now reaching this limit regularly during daytime. The generation west of Darlington Point peaks at approximately 594 MW a further 695 MW of generation is due to be commissioned in south-western NSW by the end of 2021. This has resulted in material constraints to some generators in the region.

Many of the submitters to the PSCR highlighted the impact of the constraint and the impact it will have on generation in the NEM (more detail is provided in section 3 below).

The identified need for this RIT-T is to increase overall net market benefits in the NEM through relieving existing and forecast constraints on generation connecting to the transmission network in south-western NSW. The sections below summarise the key specific sources of market benefit from the options assessed.

TransGrid notes that while AEMO implemented a further system normal constraint regarding voltage collapse in south-western NSW on 20 November 2020,[12] this constraint is not considered material for this RIT-T. Specifically, the new voltage limit announced will impose a flow limitation from Balranald to Darlington Point of 150 MW and is expected to be significantly alleviated following commissioning of EnergyConnect. While its imposition may provide additional market benefits for Option 4 and Option 5 in this RIT-T, since they can be commissioned before EnergyConnect, these benefits are not expected to be material to the assessment given that they would only accrue for a limited time and the substantially lower ranking of these two options relative to the preferred option in the NPV analysis.

2.2 Avoided and deferred capital costs of new generation and storage

Relieving the existing constraint on generation in south-western NSW and enabling existing and new renewable generation in the area to dispatch more is expected to affect the pattern of new generation and storage build in the NEM going forward. The avoided and deferred capital costs of new capacity in the NEM is a key modelled benefit of the options considered in this PADR.

Each of the credible options assessed as part of this PADR allows the constraint to be alleviated, which allows the supply-demand balance in the NEM to be met at a lower cost than if new generation and/or storage capacity in south-western NSW was to continue to be constrained in the NEM going forward.

The market modelling finds that these benefits are the largest source of market benefits and are expected from the early years of the modelling, with significant benefits accruing from the early to mid-2020s. Section 7 summarises the specific types of investment that are deferred or avoided under each of the four scenarios modelled, compared to the base case.

The central scenario is expected to have a smaller amount of investment affected in the early years, compared to the other scenarios, particularly the step-change and fast-change scenarios. A number of factors drive this result, such as significantly higher build in the base case in the step-change and fast-change scenarios and no development of VNI West under the slow-change scenario.

2.3 Avoided generator dispatch costs

The NEMDE constraint imposed by AEMO in May 2020 has had a material impact on the operation of renewable generators that have recently connected in that area. A consequence of this going forward is that more expensive generation will need to be dispatched to meet NEM demand than would occur if the constraint were not imposed. Specifically, generators with higher fuel costs than the existing and expected renewable generators adversely affected by the constraint in south-western NSW would need to be dispatched elsewhere in the NEM.

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[12] https://www.aemo.com.au/market-notices?marketNoticeQuery=&marketNoticeFacets=RECALL+GEN+CAPACITY%2CCONSTRAINTS

The wholesale market modelling undertaken in this PADR finds that the avoided dispatch costs of these higher cost generators is a significant market benefit category for the preferred option in this PADR, particularly for the central and slow-change scenarios. These cost savings are expected to accumulate as soon as the constraint can be relieved and increase until the late-2030s.

The reduced dispatch cost modelled is mainly due to reduced black coal generation in the early years, although more brown coal generation is also expected due to opening of the transfer limit from Victoria and south-western NSW to NSW load centres such as Sydney, Newcastle and Wollongong. Dispatch cost savings are expected to diminish in the mid-2030s when major black coal power plants in NSW and Queensland are assumed to retire. Section 7 summarises the specific types (and broad locations) of generation dispatch that is avoided under each of the four scenarios modelled, compared to the base case where the constraint remains in-place going forward.

Under the step-change and fast-change scenarios, avoided generator dispatch costs make up a smaller proportion of total estimated benefits (and only accrue from the early 2030s). The reduced avoided generator dispatch costs under these scenarios is driven by the imposed carbon budget in this scenario, which sees reduced generation from coal generators in the base case, reducing the opportunity for the options to accrue benefits. Coal generators are also assumed to retire half of their capacity five years earlier than in the central scenario under the step-change scenario, and two years earlier under the fast-change scenario, which reduces the opportunity for avoided generator dispatch costs for the options compared to the other scenarios.

2.4 Lower transmission costs associated with connecting REZ

The market modelling finds that there are avoided transmission costs associated with connecting REZ to the NEM for the preferred option under all scenarios, especially the step-change and fast-change scenarios.

The step-change scenario, in particular, requires significantly higher wind and solar capacity build compared to the central scenario to meet demand, due to the higher assumed carbon budget and earlier coal plant retirements. The options assessed facilitate the more efficient use of existing generation and a more even distribution of new entrant capacity, compared to the base case. The modelling finds that the preferred option avoids and defers REZ transmission expansion costs in Wagga Wagga, Darling Downs, Broken Hill and Central West Orana due to avoided/deferred solar build in those REZs, resulting in avoided transmission cost being a main contributor to benefits under this scenario.

3. Consultation on the PSCR

The PSCR was released in July 2020 and TransGrid subsequently received submissions from seven parties.

These seven submitters can be grouped into two broad categories, namely:

> existing or new renewable generators in south-western NSW – Sunraysia, Neoen, RWE, Reach Solar Energy;
> one solar generator – whom requested that their submissions be kept confidential; and
> two providers of battery systems – both of whom have requested that their submissions be kept confidential.

The two confidential submissions have not been summarised in this PADR and nor have they been published on our website.[13]

While submissions covered a range of topics, there were five broad topics that were most commented on:

> support for the identified need;
> whether the construction timetable of the new/rebuild line options is realistic;
> the ability of interim solutions to assist in the near term;
> a potential grid-connected battery option; and
> whether a stand-alone STATCOM is a technically feasible solution.

In addition, TransGrid held a number of bilateral meetings with submitters in order for them to further understand the RIT-T assessment and the option requirements in south-western NSW, as well as how proposed solutions are expected to be able to assist with meeting the identified need. These discussions have played a pivotal role in being able to define and include the two additional credible options assessed in this PADR and TransGrid thanks all parties for their time and effort to-date.

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

3.1 Support for the identified need

All of the existing or new renewable generators in south-western NSW confirmed the identified need outlined in the PSCR. They stated that the stability issues caused by outages of the existing 330 kV Wagga to Darlington Point line are causing an abundance of renewable energy (primarily solar energy) to be constrained off the market, and stated that this leads to higher prices for consumers, and severely impacts the financial viability of these generators going forward.[14]

Both Sunraysia and the solar generator stated that by the end of 2020, there is expected to be over 900 MW of generation connected in south-west NSW, with the Line 63 constraint limiting exports to approximately 300

[13] The other submissions can be accessed at: https://www.transgrid.com.au/what-we-do/projects/current-projects/Improving%20stability%20in%20south-western%20NSW

[14] Neoen submission, p. 1, RWE submission, p. 1, Sunraysia submission, p. 1, Reach Solar Energy submission, p. 2. and solar generator submission (confidentiality requested), p. 1.

MW, leaving two thirds of maximum output unable to reach consumers. They also stated that there is the potential for further constraints to limit exports even further going forward.[15]

Reach Solar Energy stated that if Option 1A, Option 1B or Option 2 are not put in place then there is a real prospect of potentially leaving NSW short of energy.[16]

This summary of current and expected constraints accords with TransGrid's views regarding constraints on generation output in south-western NSW if action is not taken. Moreover, there is now more than 900 MW of generation connected, or committed to be connected by the end of 2021, in south-west NSW.

The market modelling does not however find that there is expected to be significant unserved energy (USE) in NSW, or elsewhere in the NEM, under the base case. Avoided USE is found to be a minor benefit for each option and under each scenario modelled. This is because the output of the constrained south-western generators is made up by increased dispatch from generators elsewhere in the NEM under the base case, including new solar generation build. The benefits of avoiding higher cost dispatch and new generation build by relieving the constraints on generators in south-west NSW have been modelled as part of this PADR assessment.

3.2 Construction timetable of the new/rebuild line options

A number of parties commented on the construction timetable put forward for the options in the PSCR. Specifically, while RWE and the solar generator expressed concern that the 4-5 year expected construction timetable for Option 1B and Option 2 is ambitious,[17] Reach Solar Energy considers the programme for Option 2 in the PSCR is very conservative and state that their discussions with technical advisors/contractors suggest 12 months to design, build and commission a 160km 330kV single circuit transmission line is more accurate.[18]

There are many stages involved in planning, designing and constructing network investments like the options outlined in this RIT-T. One key stage is undertaking community and stakeholder engagement, including where new easements are required, e.g., for Option 1A and Option 2. On balance, and based on the scheduling required for recent works, TransGrid considers that the construction timetables outlined in the PSCR (which are maintained in this PADR) are realistic estimates of the time required to undertake all necessary stages for the options (including this RIT-T process).

Reach Solar Energy stated concern that Option 1A and Option 1B would be delayed if EnergyConnect is delayed due to these options requiring a connection between Darlington Point and the new Dinawan sub-station being built as part of PEC. Reach Solar Energy also stated that the acquisition of the easements would need to go through high-value, irrigated land for these options which will take considerable time and come at a significant cost, compared to utilizing the existing corridor under Option 2.[19]

While Option 1A and Option 1B are linked to the new Dinawan substation being built as part of EnergyConnect, TransGrid notes that, at the end of May 2021, the AER approved TransGrid's contingent project application which allows cost recovery for EnergyConnect.[20] The timing of the options outlined in this PADR reflects our best estimate regarding when the new Dinawan substation will be commissioned. If there

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15 Sunraysia submission, p. 1 & solar generator submission, p. 1.

16 Reach Solar Energy submission, p. 2

17 RWE submission, p. 2 & solar generator submission, p. 1.

18 Reach Solar Energy submission, p. 3.

19 Reach Solar Energy submission, pp. 3-4.

20 This represented the AER's final regulatory approval for the new South Australia to New South Wales interconnector to be built by ElectraNet and TransGrid. The AER's decision approved the final and efficient costs for EnergyConnect following contingent project applications from ElectraNet and TransGrid. See: https://www.aer.gov.au/news-release/aer-approves-costs-for-project-energyconnect

are changes to the expected timing of this new substation following publication of the PADR, we will address them in the PACR.

The costs of acquiring the required easements for each option have been reflected in the updated cost estimates presented in this PADR. These costs reflect expectations regarding the land-use for each easement and its impact on the expected easement cost.

All of the existing or new renewable generators in south-western NSW wanted to explore the possibility of expediting the RIT-T process and/or having it undertaken in an urgent manner.[21] TransGrid notes that it is endeavouring to undertake this RIT-T in as timely a fashion as possible, while allowing adequate time to comprehensively liaise with stakeholders and assess all options available, including those proposed in submissions. The RIT-T process, and the post-RIT-T process, have well-codified timeframes for consultation set-out in the NER and we are not able to expedite these processes beyond the NER requirements.

3.3 The use of interim solutions

A number of the existing or new renewable generators in south-western NSW expressed interest in TransGrid exploring possible interim solutions that can provide relief in the short and medium term, while a longer term solution is worked out through the RIT-T.[22]

One of the confidential submitters has proposed a battery solution to be deployed to assist before a longer-term option can be commissioned. TransGrid has modelled this solution as an addition to the highest ranked credible network line option, as outlined in section 4 below. TransGrid does not consider that there are other interim solutions that can assist and nor have any proponents reached out with proposals.

3.4 Grid-connected battery solution

One of the confidential submitters proposed a grid-connected battery solution as a standalone long-term option. Having reviewed the proposal and discussed it with the proponent, TransGrid has included this option as a credible option in this PADR assessment (Option 5).

This party also queried the assumption in the PSCR that batteries would require coupling with a STATCOM and so would always be more expensive than a STATCOM solution (i.e., Option 3), without providing commensurately greater market benefits. While TransGrid maintains this view, the battery option without a STATCOM has been modelled for this PADR (i.e., Option 5) and it was found that even without the STATCOM the battery option is not expected to deliver positive net benefits on a weighted basis.

3.5 The use of STATCOMs

Reach Solar Energy stated that they have consulted with their own technical advisors and believe that the STATCOM option is an incomplete and inadequate solution.[23]

Neoen encourages the exploration of a D-VAR type STATCOM option, which they state tend to operate more quickly than traditional STATCOMs and may show that the constraint can be fully alleviated rather than only partially.[24]

TransGrid has modelled the STATCOM option as part of this PADR (i.e., Option 3). The NPV analysis indicates that this option has a significantly negative net market benefit, and therefore is not preferred to the

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21 Sunraysia Solar Farm submission, p. 1, RWE submission, p. 2, Reach Solar Energy submission, p. 4, solar generator submission, p. 2 and. Reach Solar Energy submission, p. 2.

22 Sunraysia Solar Farm submission, p. 1, RWE submission, p. 2 & solar generator submission, p. 2.

23 Reach Solar Energy submission, p. 4

24 Neoen submission, pp. 1-2.

‘do nothing’ base case. As a consequence, the question of the technical viability of the STATCOM solution and whether it would be complete solution has become moot and we have not needed to investigate the technical issues associated with this option further.

4. Credible options assessed

TransGrid has assessed the following five types of credible options:

> Option 1 – a new or rebuilt 330 kV transmission line between Darlington Point and the new Dinawan substation being constructed for EnergyConnect:
  – Option 1A (new line);
  – Option 1B (rebuilt line);
> Option 2 – a new 330 kV transmission line between Darlington Point and the Wagga Wagga substation;
> Option 3 – a static synchronous compensator (STATCOM) solution at the Darlington Point substation;
> Option 4 – Option 1A plus an interim 3-year battery solution; and
> Option 5 – a standalone long-term battery solution.

The options assessed include two that were proposed in submissions to the PSCR, namely a 3 year interim network support contract provided via a battery solution prior to the construction of a network solution (i.e., Option 4) and a stand-alone battery solution (Option 5).

Table 4-1 below summarises each of the credible options.

The assumed timing for each option is to be reviewed and updated as part of the PACR, including where it has been informed by a third party submission.

Table 4-1: Summary of the credible options

Option	Description	Estimated capital cost	Expected delivery time
1A	Establish a new Darlington Point to Dinawan 330 kV transmission line	$211 million	4-5 years
1B	Rebuild the existing 99T Darlington Point to Coleambally and 99L Coleambally to Deniliquin as 330 kV to Dinawan	$303 million	4-5 years
2	Establish a new Wagga Wagga to Darlington Point 330 kV transmission line	$393 million	4-5 years
3	STATCOM	$50 million for a 100 MVar STATCOM	3-4 years
4	Option 1A + 3-year interim network support solution utilising a battery (proposed by a confidential submitter)	$211 million (for network component) Confidential for network support	4-5 years for the network component Network support from battery available from Q1 2022
5	A standalone long-term battery solution (proposed by a confidential submitter)	Confidential	2022/23 commissioning

The interim 3-year battery solution has not been coupled with either Option 1B or Option 2 since the network component of these two options is significantly more expensive than Option 1A and the market modelling indicates that neither are expected to have commensurately greater market benefits than Option 1A. Option

1B and Option 2 with an interim 3-year battery solution would not therefore rank higher in the RIT-T assessment than Option 1A with the interim 3-year battery solution.

All network options are assumed at this stage to have annual operating and maintenance costs equal to approximately one per cent of their capital costs.

Capital costs have been revised since the PSCR in order to take account of current market trends and risks, drawing on the experience of recent projects.

The costs of the non-network options (i.e., the interim battery network support component for Option 4 and the stand-alone battery solution in Option 5) have been incorporated in the PADR assessment in line with the revised guidance provided by the AER as part of its recent update of the RIT-T Application Guidelines.[25] In particular, since neither of the non-network options are currently committed or anticipated projects (as defined in the RIT-T) the PADR assessment reflects:

> the proposed network support cost as the cost of the option
> the same network support cost as a benefit to the option proponent; and
> the full capital and operating costs of the option as part of the 'costs for parties other than the RIT-T proponent' category of market benefits.

The market benefits associated with the operation of the non-network options outside of the times needed for network support have also been reflected in the assessment of market benefits (see section 6).

The remainder of this section provides further detail on each of these options. It also outlines further options that have been considered but not progressed (and the reasons why).

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

4.1 Option 1A – New Darlington Point to Dinawan 330 kV transmission line

Option 1A involves the establishment of a greenfield transmission line between Darlington Point and the new Dinawan substation that will be developed as part of EnergyConnect.

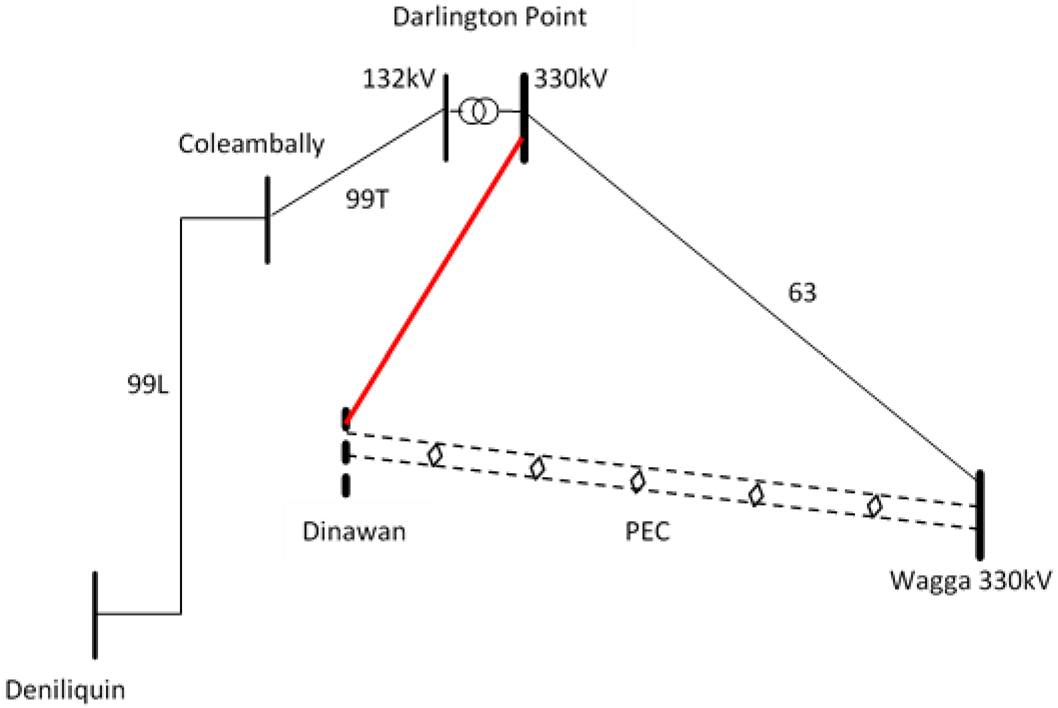
The high-level scope of this option includes:

> construct a single circuit 330 kV transmission line from Darlington Point to Dinawan (approximately 90 km); and
> install new 330 kV switchbays at Darlington Point and Dinawan substations.

Figure 4-1 provides a network diagram for Option 1A, which highlights the new network elements in red.

[25] AER, *Guidelines to make the Integrated System Plan actionable*, Final decision, August 2020, p. 26.

Figure 4-1: Option 1A network diagram



The estimated capital cost of Option 1A is $211 million. Delivery is expected to take 4-5 years, with commissioning possible in 2024/25, subject to obtaining necessary environmental and development approvals.

4.2 Option 1B – Rebuilt Darlington Point to Dinawan 330 kV transmission line

Option 1B involves the rebuild of existing 132 kV transmission lines to establish a 330 kV connection between Darlington Point and the proposed Dinawan substation.

The high-level scope of this option includes:

> rebuild the existing 99T Darlington Point to Coleambally 132 kV circuit as a 330 kV single circuit transmission line (approximately 13 km);

> rebuild a section of the existing 99L Coleambally to Deniliquin 132 kV circuit (from Coleambally to where it crosses the new EnergyConnect interconnector) as a 330 kV double circuit transmission line (approximately 40 km), with one side to be operated at 132 kV;

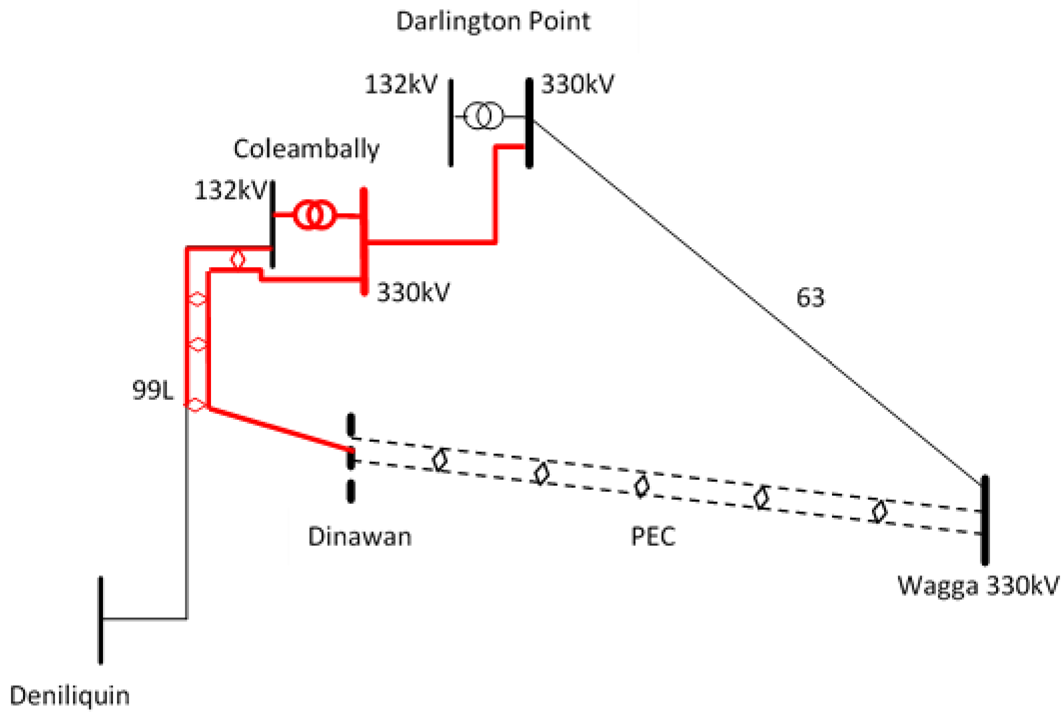
> build a new 330 kV single circuit from where the 99L line crosses the new EnergyConnect interconnector to the proposed Dinawan substation (approximately 35 km);

> establish a 330 kV busbar and install a 330/132 kV transformer at Coleambally 132/33kV substation; and

> install new 330 kV switchbays at Darlington Point and Dinawan substations.

Figure 4-2 provides a network diagram for Option 1B, which highlights the new network elements in red.

Figure 4-2: Option 1B network diagram



The estimated capital cost of Option 1B is $303 million. Option 1B is more expensive than Option 1A due to the cost of erecting the existing 132 kV transmission line and rebuild as 330 kV double circuit transmission line under Option 1B (Option 1A on the other hand only needs to build a new 330 kV single circuit transmission line).

Delivery is expected to take 4-5 years, with commissioning possible in 2024/25, subject to obtaining necessary environmental and development approvals.

4.3 Option 2 – New Wagga Wagga to Darlington Point 330 kV transmission line

Option 2 involves the establishment of a new 330 kV single circuit transmission line between Wagga Wagga 330/132 kV substation and Darlington Point substation.

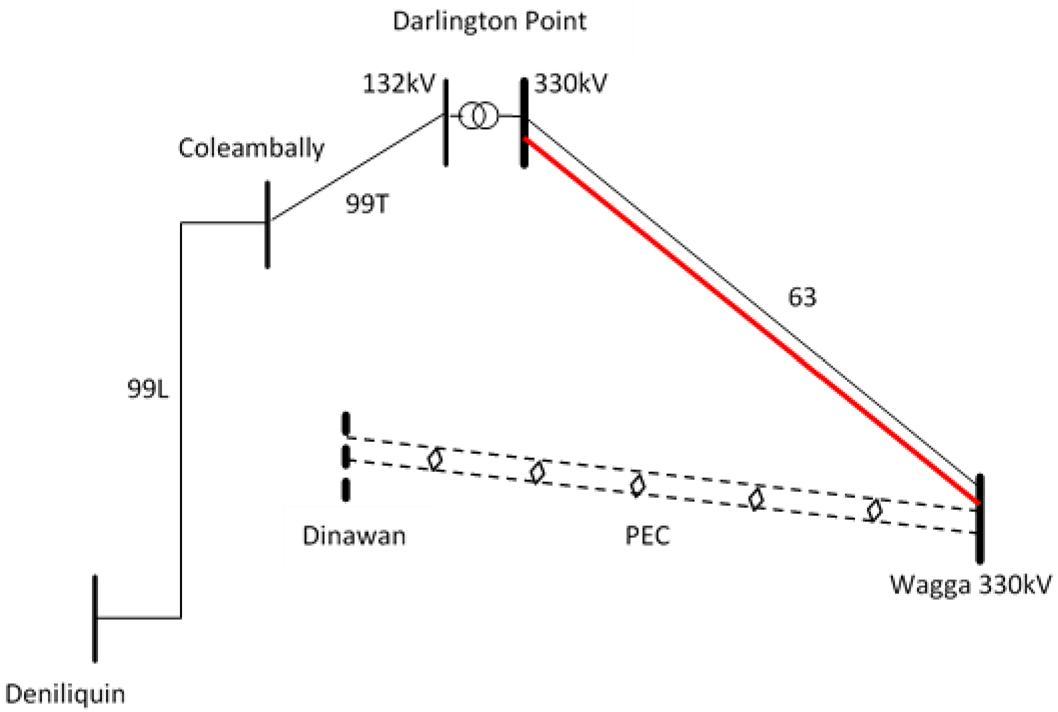
The high-level scope of this option includes:

> construct a single circuit 330 kV transmission line from Wagga Wagga to Darlington Point (approximately 150 km); and

> install new 330 kV switchbays at Wagga Wagga 330/132 kV substation and Darlington Point substation.

Figure 4-3 provides a network diagram for Option 2, which highlights the new network elements in red.

Figure 4-3: Option 2 network diagram



The estimated capital cost of Option 2 is $393 million. Delivery is expected to take 4-5 years, with commissioning possible in 2024/25, subject to obtaining necessary environmental and development approvals.

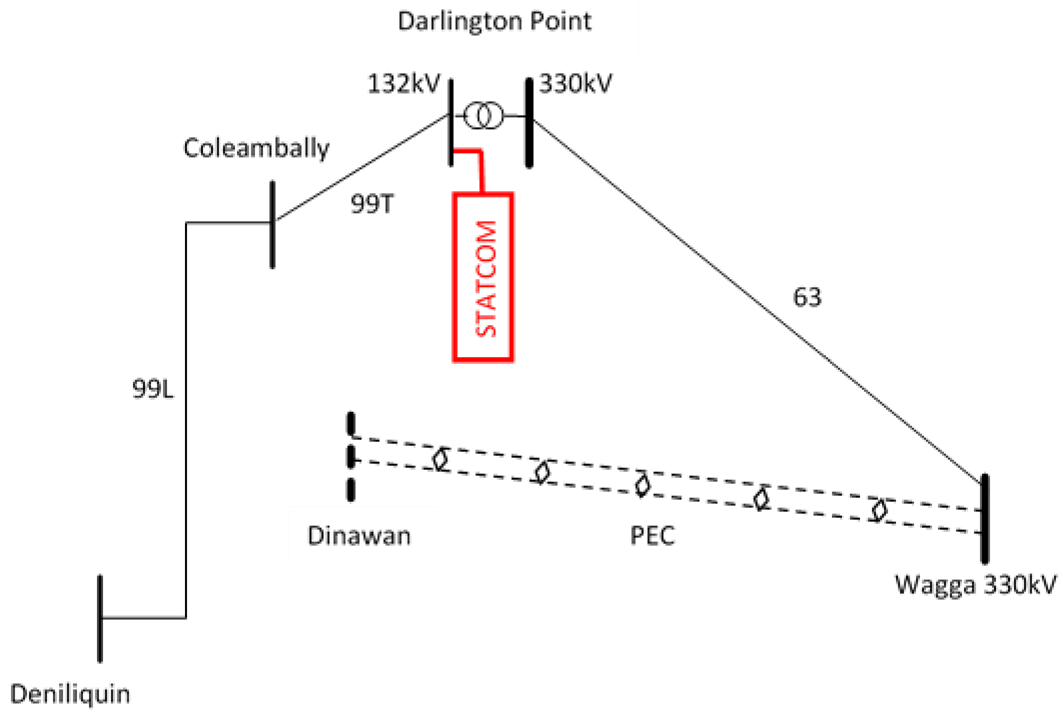
4.4 Option 3 – STATCOM

Option 3 involves the use of a STATCOM to assist in meeting the constraint.

TransGrid noted in the PSCR that a STATCOM may not actually be able to fully alleviate the constraint but, instead, may enable the constraint to be modified to be less severe and thus still provide market benefits. Notwithstanding, TransGrid has included the STATCOM solution on an indicative basis in the PADR analysis to identify whether, if it was technically feasible, it could be the preferred solution.

Figure 4-4 provides a network diagram for Option 3, which highlights the new network elements in red.

Figure 4-4: Option 3 network diagram



The estimated capital cost of Option 3 is $50 million. Delivery is expected to take 3-4 years, with commissioning possible in 2023/24, subject to obtaining necessary environmental and development approvals.

4.5 Option 4 – Option 1A with an interim 3-year battery solution

Option 4 involves the exact same network components as Option 1A outlined above as well as the use of a battery solution for three years to provide network support before the new network can be commissioned, as proposed by a confidential submitter.

The estimated costs of the network elements are $211 million and the estimated costs of the battery have been kept confidential, as requested by the submitter. The network support component would be available in 2021/22. Delivery of the network element is expected to take the same time as Option 1A.

4.6 Option 5 – Standalone long-term battery solution

Option 5 involves a standalone battery solution in the long-term, i.e., as a substitute for a traditional network solution and not as a complement to it (in contrast to Option 4). The battery could be commissioned in 2022-23. This solution has been proposed by a confidential submitter and so its costs have been kept confidential in this PADR, as requested.

4.7 Options considered but not progressed

TransGrid has also considered whether other network options could meet the identified need. The reasons these options have not been progressed any further are summarised in Table 4-2. These options were not commented on in submissions to the PSCR.

Table 4-2: Options considered but not progressed

Option	Reason(s) for not progressing
Rebuild Line 63 as double circuit 330 kV transmission line	This option would be considerably more expensive than the other network options outlined above (due to it being double-circuit and also requiring significant demolition costs) and would require extended outage of Line 63 (which would exacerbate the effects of the generation constraints in the area). This option is therefore considered inferior to the credible network options outlined above and not commercially feasible under the RIT-T.
Synchronous condensers	Synchronous condensers are not considered able to respond fast enough to meet the identified need. They are therefore not considered technically feasible since they cannot meet the identified need.

5. Ensuring the robustness of the analysis

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 reasonable 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 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. TransGrid has identified the 'threshold value' for key factors, beyond which the outcome of the analysis would change.

5.1 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. 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, which differ in terms of the key drivers of the estimated net market benefits. Specifically, TransGrid has modelled the market benefits of each of the options across each of the following four 2020 ISP scenarios:

> central;
> slow-change;
> step-change; and
> fast-change.

The high DER scenario from the 2020 ISP has not been modelled as the variations in the assumptions these scenarios embody are already reflected in the four scenarios outlined above. TransGrid considers that focussing the assessment on the four scenarios above reflects a proportionate approach to undertaking the modelling for this PADR and is consistent with the principles of the RIT-T.

There are a small number of assumptions that differ slightly from those used by AEMO in the final 2020 ISP. These are as follows:

> forecast gas prices that are lower than those adopted in the 2020 ISP:
  – the gas price forecasts used align with those TransGrid commissioned previously in response to an inquiry made by the AER earlier in 2020 in relation to the HumeLink PADR and reflect the forecast impact on prices of the Memorandum of Understanding (MOU) between the Federal government and the NSW government in February 2020;
  – the forecast prices are lower than those used in the 2020 ISP and are more closely aligned with AEMO's latest gas price forecasts being developed as part of its revised Input and Assumptions Report.
> assumed REZ limits for the South West NSW REZ are higher than the 2020 ISP assumptions, following the commissioning of EnergyConnect:

- the 2020 ISP REZ modelling was based on the EnergyConnect scope set-out in the EnergyConnect PACR, while the updated REZ limit reflects the updated EnergyConnect scope following detailed design work, and set out in the contingent project application;
    - the definition of the 'South West REZ' is different from the ISP definition but aligns with the NSW government definition;
- the retirement dates for coal-fired generators centre on variations from their announced retirement dates:[26,27]
- outage rates for coal plants:
    - the ISP does not have coal outage rates for individual power stations;
    - EY has assumed outage rates based on their analysis of historical generator performance;
- an earlier commissioning date for VNI West under the central scenario than in the core 2020 ISP assumptions, consistent with AEMO's accelerated delivery date in the 2020 ISP (and AEMO's draft 2021 Inputs, Assumptions and Scenarios Report (IASR) timing):[28,29]
    - specifically, we have assumed a timing of 2028/29 for VNI West under the central scenario.[30]
- QNI minor is assumed to be commissioned 1 July 2022 and the NSW CWO REZ on 1 July 2025:
    - the 2020 ISP assumes 2021/22 and 2024/25 for each of these developments, respectively;
    - the assumptions adopted are based on our current expectations regarding the timing of these developments and differ only minorly compared to the ISP.

TransGrid has investigated a sensitivity that aligns the majority of the assumptions used with the AEMO 2020 ISP assumptions (and the gas prices in the November 2020 AEMO release (see section 7.6.3)), focusing on the central scenario. This sensitivity demonstrates that the choice of preferred option, and whether there is a preferred option with a positive net benefit, is unlikely to be dependent on the departures made from the ISP assumptions.

Table C-2 in Appendix C summarises the key variables in each scenario that influence the net benefits of the options.

TransGrid has weighted each of the four scenarios equally (i.e., 25 per cent each). While an equal weighting has been applied to weight the estimated market benefits and identify the preferred option across scenarios (illustrated in section 7), TransGrid has also carefully considered the results in each scenario in section 7. TransGrid has also investigated a sensitivity that amends the scenario weightings applied based on recent commentary from the ESB (presented in section 7.6.3).

TransGrid notes that there are a number of differences between the assumptions applied in this PADR and those adopted for the recently published HumeLink PACR. This is due to the time at which the market modelling for each was undertaken.

TransGrid intends to update the analysis in the PACR to reflect the final 2021 IASR, as well as any other recent relevant market developments not captured in these assumptions.

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26 These assumptions are: (1) under the slow-change scenario, half of coal power stations' capacity is retired 5 years later than end-of-technical-lives; (2) under the central scenario, retired by announced retirement date or end-of-technical-lives; (3) under the fast-change scenario, half of coal power stations' capacity is retired 2 years earlier than end-of-technical-lives; and (4) under the step-change scenario, half of coal power stations' capacity is retired 5 years earlier than end-of-technical-lives.

27 This assumption was also adopted in the HumeLink PADR published in 2020, together with sensitivity analysis that showed that it was not material to the RIT-T outcome.

28 AEMO, *2020 Integrated System Plan*, July 2020, p. 82.

29 TransGrid notes that the final 2021 IASR assumptions report states that states the timing of VNI West will be an outworking of the forthcoming 2022 ISP, see: AEMO, *2021 Inputs, Assumptions and Scenarios Report*, July 2021, p. 151.

30 While AEMO has an accelerated delivery date of 2027/28 for VNI West in the 2020 ISP (and draft 2021 IASR), TransGrid has assumed a commissioning of 1 July 2028 as this is TransGrid's current view of the earliest practical delivery date.

5.2 Sensitivity analysis

In addition to the scenario analysis, TransGrid has 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:

> changes in the network capital costs of the credible options;
> alternate commercial discount rate assumptions;
> increasing the weighting of the step-change scenario, in-line with recent commentary from the ESB; and
> alignment with the 2020 ISP assumptions (and recent AEMO gas price forecasts).

The results of the sensitivity tests are discussed in section 7.6.

In addition, TransGrid has also sought to identify the 'threshold value' for key variables beyond which the outcome of the analysis would change.

6. Estimating the market benefits

As outlined in section 2, the key benefits expected from the options are avoided generator dispatch cost, more efficient building of new capacity and lower transmission costs associated with connecting REZ.

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 is required to connect REZ across the NEM).

This section outlines how each of the broad categories of market benefit have been estimated.

EY has undertaken the wholesale market modelling component of the PADR assessment. Appendix C provides additional detail on the wholesale market modelling undertaken by EY.

EY 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.

6.1 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 (in particular, the cost of connecting REZs);
> 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.

6.1.1 Changes in fuel consumption in the NEM

This category of market benefit is expected where credible options result in different patterns of generation and storage dispatch across the NEM, compared to the base case.

In particular, one of the key effects of improving the stability of the south-western NSW power system comes from enabling demand centres to be supplied by lower cost generation than can be expected if no upgrade is undertaken. The market modelling finds that new renewable generation avoids the need for black coal generation to operate. As outlined in section 7, this is the largest category of benefit estimated (except under the step-change scenario).

The modelling of this benefit not only captures the changed patterns of generation and storage dispatch across the NEM, compared to the base case, from relieving the constraint, but also from new batteries as part of Option 4 and Option 5 being able to trade in the wholesale market outside of their network support commitments. This however makes up a small proportion of the benefits estimated.

6.1.2 Changes in costs for other parties in the NEM

This category of market benefit is expected where credible options result in different investment patterns of generators and large-scale storage across the NEM, compared to the base case. In particular, the market modelling finds that there are large amounts of new build deferred and avoided with the preferred option in place. As shown in section 7, these avoided or deferred costs are the second most material category of market benefit estimated across the options (except for under the step-change and fast-change scenarios where they are the largest benefit).

The capital and operating costs associated with the battery component under Option 4 and Option 5 have been captured in the PADR assessment as a cost to other parties, reflecting that this is an additional resource cost to the NEM that would not be incurred if we did not sign a network support agreement with the proponents for these options (as these projects are not already committed or anticipated). This is consistent with the AER's revised guidance on the treatment of NNO.[31] However, the market benefits associated with these options operating outside of times needed for network support (in particular their impact on dispatch costs and generation investment), compared with the base case in which those batteries are not in place, has also been captured as part of the modelling for each of these options.[32]

6.1.3 Differences in unrelated transmission costs

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

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

The market modelling undertaken finds that there are significant avoided transmission costs associated with connecting REZ to the NEM for the preferred option under the step-change scenario and in other scenarios to a lower extent. As outlined in section 2.4, this is driven by the need to develop REZ to meet demand given the higher assumed carbon budget and earlier coal plant retirements under this scenario

We note that the NSW Government Roadmap has not been reflected in the modelling assumptions for this PADR but is intended to be reflected in the PACR analysis.

6.1.4 Changes in involuntary load curtailment

Improving the stability of the south-western NSW power system increases the generation supply availability from existing and new generation to meet New South Wales demand. 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 the AER VCRs to quantify the estimated value of avoided EUE 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.

6.1.5 Changes in voluntary load curtailment

Voluntary load curtailment is when customers agree to reduce their load once wholesale 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 wholesale price outcomes, and in

[31] AER, *Guidelines to make the Integrated System Plan actionable*, Final decision, August 2020, p. 26.

[32] In the case of Option 4, the impact of the battery solution on market outcomes for the remaining life of the battery following the period in which it is needed for network support has been incorporated in the modelling.

particular results in wholesale 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 is not significantly different between the option cases and the base case.

6.1.6 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 each 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 is captured within the wholesale market modelling of dispatch cost benefits of avoided fuel costs and changes to voluntary and involuntary load shedding.

The reduction in network losses between the base case and the options is considered immaterial for the options considered in this PADR but reduces both the energy to be produced by fossil fuel generators to account for the losses, and a reduction in new capacity that has to be built to supply demand, particularly during peak periods.

6.2 General modelling parameters adopted

The RIT-T analysis spans a 25-year assessment period from 2021-22 to 2045-46.

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. The terminal values are calculated as the undepreciated value of capital costs at the end of the analysis period and can be interpreted as a conservative estimate for benefits (net of operating costs) arising after the analysis period. TransGrid notes that for this RIT-T, the terminal value assumption is not material in terms of the outcome, with the benefits generated by the preferred option exceeding the total estimated project costs before the end of the assessment period.

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, consistent with the assumptions adopted in the 2020 ISP. The RIT-T 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. TransGrid has therefore tested the sensitivity of the results to a lower bound discount rate of 2.23 per cent,[33] and an upper bound discount rate of 7.90 per cent.

6.3 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.[34]

Option value is likely to arise in a RIT-T assessment where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change. The credible options outlined in this PADR do not

[33] 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/directlink-determination-2020-25

[34] NER clause 5.16.1(c)(6).

exhibit flexibility in terms of how they can be developed. TransGrid does not therefore consider at this stage that option value to be a material category of market benefit for this RIT-T.

In addition, the calculation of option value requires substantial additional modelling. TransGrid considers that this modelling exercise would be disproportionate to any option value that may be identified for this specific RIT-T assessment, particularly the *difference* between options in terms of these benefits.

Competition benefits under the RIT-T relate to net changes in market benefits arising from the impact of the credible option on the bidding behaviour of market participants in the wholesale market. While each of the credible options considered are designed to address network constraints between competing generating centres, competition benefits are unlikely to be material between the options and so have not been estimated as part of this PADR. This is due to all options being expected to have a similar effect on the wholesale market through relieving the existing constraint in south-western NSW.

However, competition benefits are unlikely to be material *between* the options, TransGrid may review competition benefits further as part of the PACR assessment as they may be a material source of benefit for the options relative to the base case.

7. Net present value results

This section outlines the results of the assessment TransGrid has undertaken of the credible options.

Due to the confidentiality requested by the proponents of the battery solutions, TransGrid is only able to present the overall *net* market benefits of Option 4 and Option 5 (i.e., the present value of the aggregate market benefits estimated less the present value of the aggregate costs).

The accompanying market modelling report provides additional detail in terms of the modelled wholesale market impacts for each option, under each scenario. Neither this PADR nor the accompanying market modelling report provide the estimated wholesale market benefits of Option 4 and Option 5 in dollar terms, in order to protect the confidentiality of the options assessed.

7.1 Central scenario

The central scenario reflects AEMO's central demand forecasts, neutral coal price forecasts and coal plants retiring when announced (or at the end of their technical lives). As outlined in section 5.1, forecast gas prices applied align with the central forecasts adopted in response to an inquiry made by the AER in 2020 in relation to the HumeLink PADR and reflect the impact of the MOU between the Federal government and the NSW government in February 2020.

Under these assumptions, all options are found to have net costs, meaning that they are not preferred over the base case 'do nothing' option. Option 1A, which is the overall top-ranked investment option on a weighted basis (see section 7.5), is estimated to result in approximately $65 million in net costs. Option 3 is the top-ranked investment option but is still found to result in a net cost of $17 million over the assessment period.

Figure 7-1 shows the overall estimated net benefit for each option under the central scenario.

Figure 7-1: Summary of the estimated net benefits under the central scenario

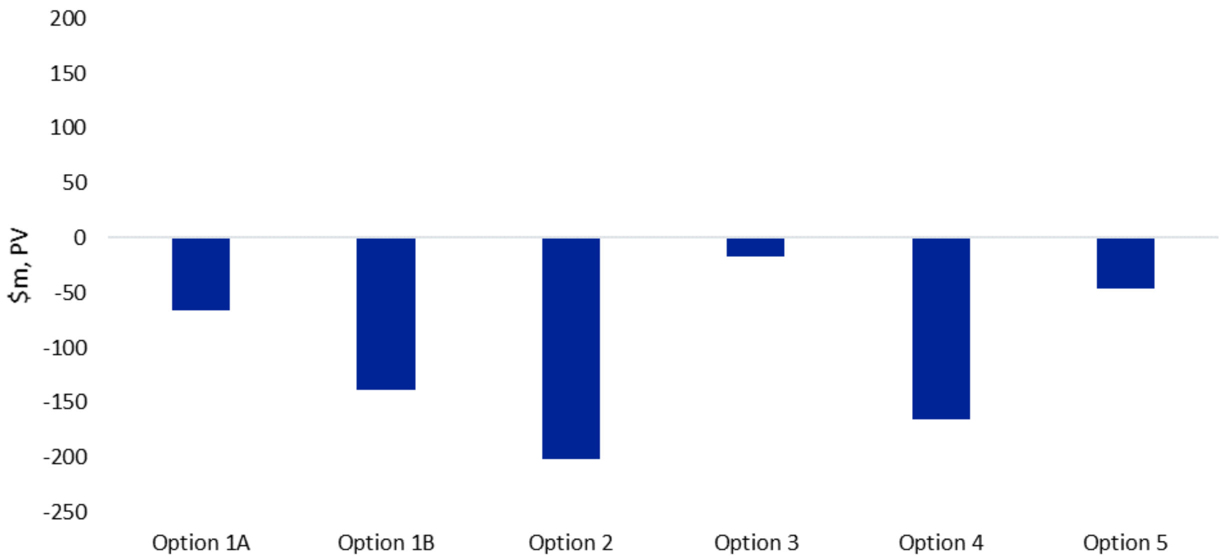
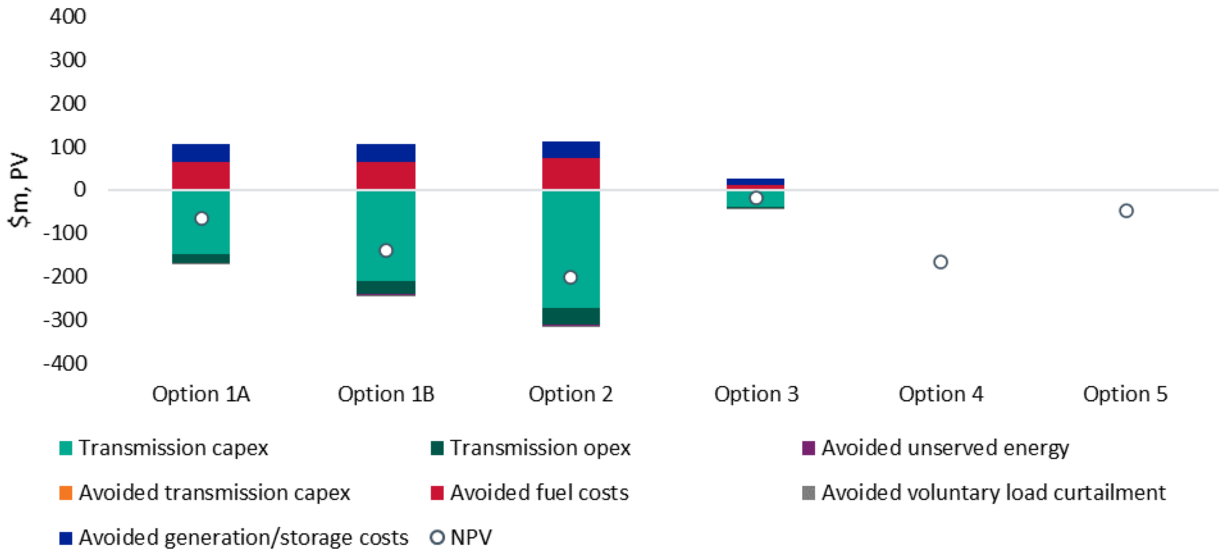


Figure 7-2 shows the composition of estimated net benefits for each option under the central scenario. Only the net numbers are shown for Option 4 and Option 5 in order to protect the confidentiality of these options.

Figure 7-2: Breakdown of estimated net benefits under the central scenario



The wholesale market modelling for Option 1A finds that the primary sources of benefit are from avoided fuel cost savings and avoided and deferred capex for new generation/storage. These two categories of market benefit make up approximately 99 per cent of the total estimated gross benefit for Option 1A.

The market modelling finds that these two benefits are attributable to the following:

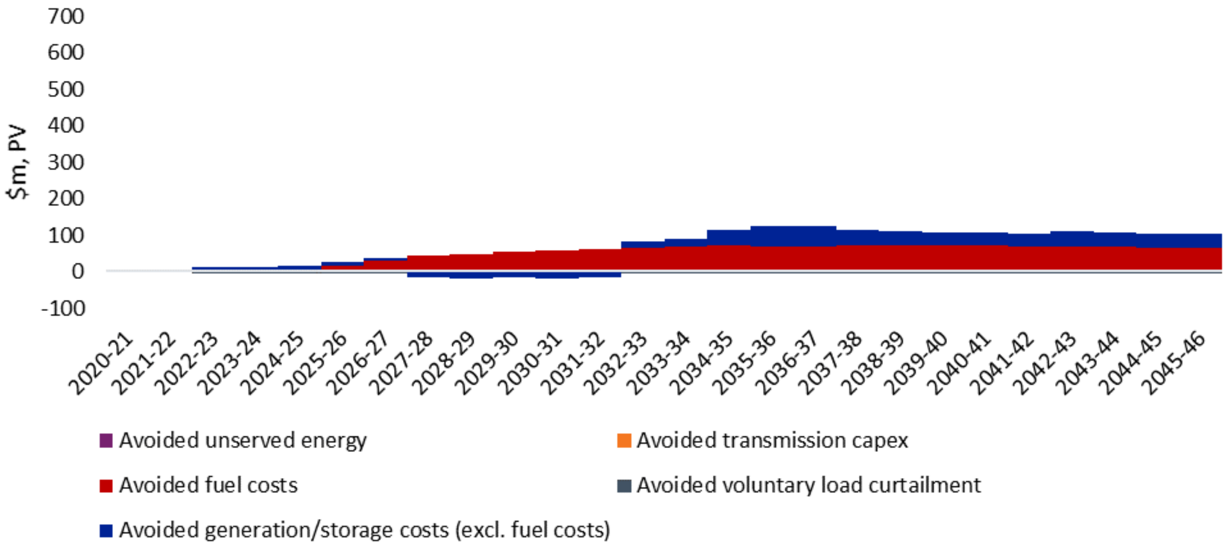
> fuel cost savings are expected to accumulate as soon as the option is commissioned and increase until the mid-2030s:
  - the fuel cost savings are mainly due to reduced black coal generation in the early years (although more brown coal generation is expected due to the opening of the transfer limit from Victoria and south-western NSW to NSW load centres);
  - fuel cost savings are expected to diminish in the mid-2030s when major black coal power plants in NSW and Queensland are assumed to retire;

> while a small capex saving is expected from 2022-23 due to deferred capacity investment for a few years, the major capex saving occurs around the mid-2030s and remains stable across the assessment period:
  - the reduced capex is mainly due to deferral and avoidance of grid-scale solar generation: the modelling finds that around 180 MW of solar build is avoided by the end of the period (and approximately 55 MW more wind generation is forecast to be built).

While Option 2 and the battery options (i.e., Options 4 and 5) are estimated to provide the greatest level of gross benefits of all options, the significantly greater capital cost of these options means that they also have significant net costs associated with them (especially for Option 2 and Option 4).

Figure 7-3 below presents the estimated cumulative expected gross benefits for Option 1A for each year of the assessment period under the central scenario. It shows that the majority of the overall benefits have accrued by 2034/35 under this scenario.

Figure 7-3: Breakdown of cumulative gross benefits for Option 1A under the central scenario[35]



7.2 Step-change scenario

The step-change scenario reflects a state of the world where there is strong action on climate change and a 'step-change' in emissions, including AEMO's step-change demand forecasts, fast coal price forecasts and coal plants retiring earlier than the central scenario. Forecast gas prices applied align with the step-change forecasts adopted in response to the inquiry made by the AER in 2020 in relation to the HumeLink PADR and reflect the impact of the MOU between the Federal government and the NSW government in February 2020.

TransGrid notes that recent commentary from the ESB suggests that the NEM is in fact tracking closest to the step-change currently.[36]

Under these assumptions, Option 1A is estimated to deliver approximately $159 million in net benefits. This represents approximately $40 million or 34 per cent greater net benefits than the second-ranked option (Option 4).

Figure 7-4 shows the overall estimated net benefit for each option under the step-change scenario.

[35] This figure only presents the annual breakdown of estimated gross benefits for the preferred investment option (Option 1A). Since this figure shows the cumulative gross benefits in present value terms, the height of the bar in the last year equates to the gross benefits for Option 1A shown in Figure 7-2 above. This applies to all figures of this type in this document.

[36] See Argus Media, Australia tops step-change energy transition scenario, Morrison, K., 7 May 2021 (accessed via https://www.argusmedia.com/en/news/2212777-australia-tops-stepchange-energy-transition-scenario on 7 July 2021) , Renew Economy, *"We are headed for step change:" ESB's Kerry Schott on new market design,* Parkinson, G., 30 September 2020 (accessed via https://reneweconomy.com.au/we-are-headed-for-step-change-esbs-kerry-schott-on-new-market-design-89487/ on 7 July 2021) & ESB, *The Health of the National Electricity Market 2020*, Volume 1: The ESB Health of the NEM Report, 5 January 2020, p. 8.

Figure 7-4: Summary of the estimated net benefits under the step-change scenario

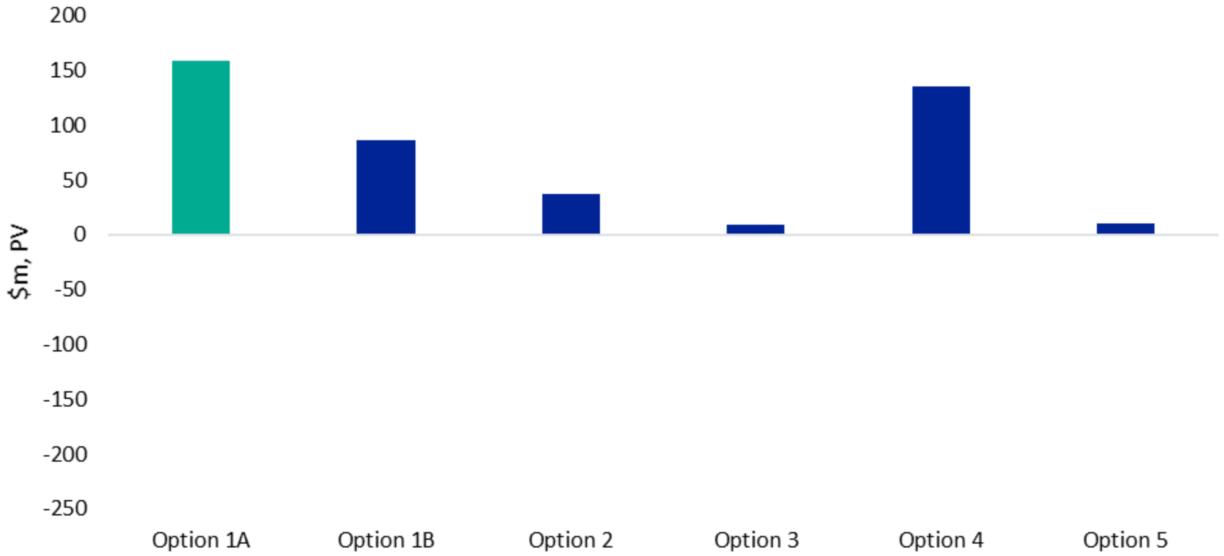
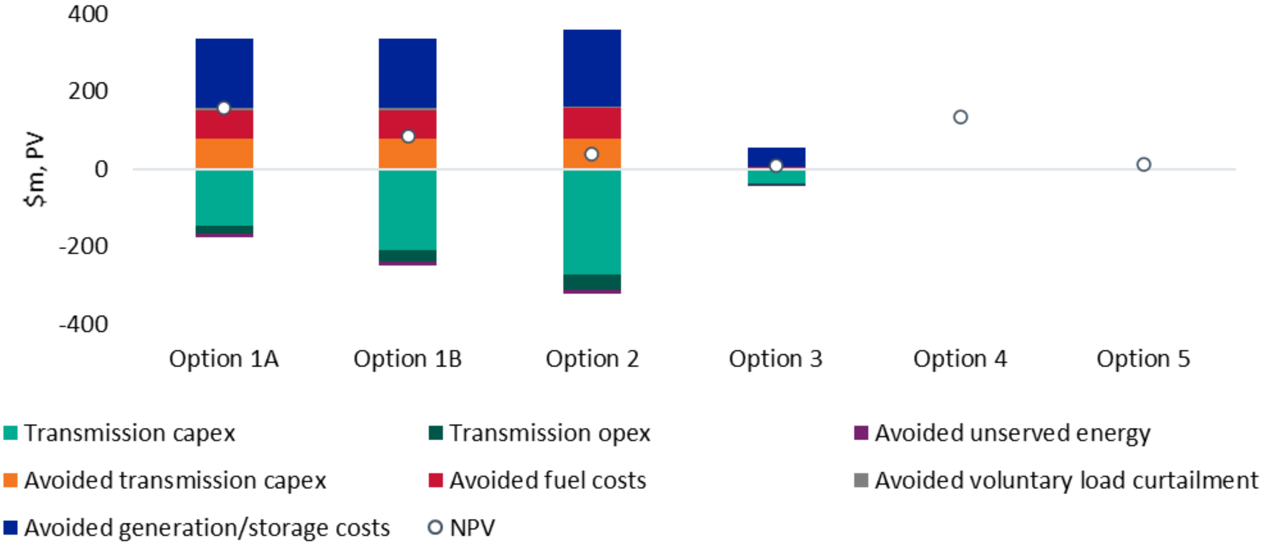


Figure 7-2 shows the composition of estimated net benefits for each option under the step-change scenario. Only the net numbers are shown for Option 4 and Option 5 in order to protect the confidentiality of these options.

Figure 7-5: Breakdown of estimated net benefits under the step-change scenario



The wholesale market modelling for Option 1A finds that the primary sources of benefit are from avoided and deferred capex for new generators/storage as well as REZ transmission expansion and fuel cost savings. These categories of market benefit make up all the estimated gross benefit for Option 1A.

The market modelling finds that these benefits are attributable to the following:

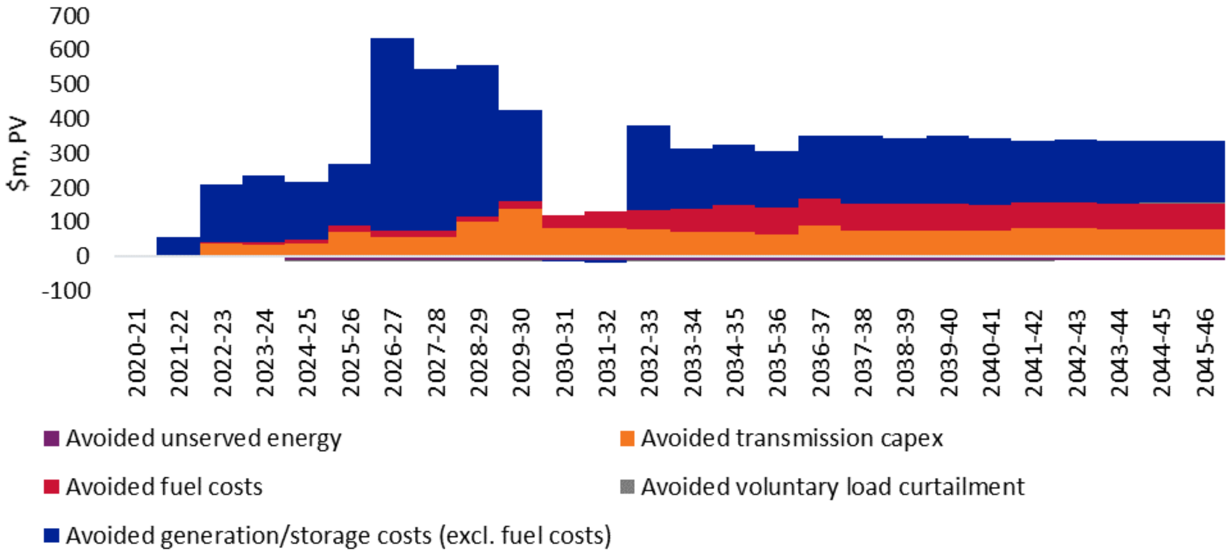
> the capex saving is expected to start from 2021/22 and increases up to 2026/27:
  - it is forecast that around 750 MW of solar is deferred until the early 2030s, and around 400 MW solar build is deferred from the mid-2030s until the early 2040s (where slightly more solar is built than the base case);
  - large scale storage is also forecast to be avoided from the mid-2030s, summing to just above 200 MW by the end of assessment period;
  - on the other hand, more wind is forecast to be brought forward from the 2040s to the mid-2020s;

> the REZ expansion saving is expected to begin in the early 2020s:
  – the modelling finds that Option 1A avoids and defers REZ transmission expansion in Wagga Wagga, Darling Downs, Broken Hill and Central West Orana due to avoided/deferred solar build in those REZs;
> fuel cost savings are expected to mainly accrue from in the 2030s, where some black coal and CCGT generation is avoided under Option 1A.
  – the reduced fuel cost savings under this scenario compared to the central scenario is driven by the higher imposed carbon budget in this scenario, which sees reduced generation from coal generators in the base case, reducing the opportunity for the options to accrue benefits from displacing this generation, as well as coal generators being assumed to retire half of their capacity five years earlier than in the central scenario.

While Option 2 and the battery options (i.e., Options 4 and 5) are estimated to provide the greatest level of gross benefits of all options, the greater capital cost of these options means that they are ranked significantly below Option 1A (especially Option 2, which has significant net costs).

Figure 7-6 below presents the estimated cumulative expected gross benefits for Option 1A for each year of the assessment period under the step-change scenario. It shows that there is significant variation in avoided generation/storage costs in early years, reflecting timing changes in investments with the benefit stabilising in the mid-2030s.

Figure 7-6: Breakdown of cumulative gross benefits for Option 1A under the step-change scenario



7.3 Slow-change scenario

The slow-change scenario is comprised of a set of conservative assumptions reflecting a future world of lower demand forecasts, slow coal price forecasts and coal plants retiring later than under the central scenario. Forecast gas prices applied align with the slow-change forecasts adopted in response to the inquiry made by the AER in 2020 in relation to the HumeLink PADR and reflect the impact of the MOU between the Federal government and the NSW government in February 2020.

Under these assumptions, Option 1A is estimated to deliver approximately $23 million in net benefits. This represents approximately $38 million more net benefit than the second-ranked option (Option 3), which has an expected net cost of $15 million.

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

Figure 7-7: Summary of the estimated net benefits under the slow-change scenario

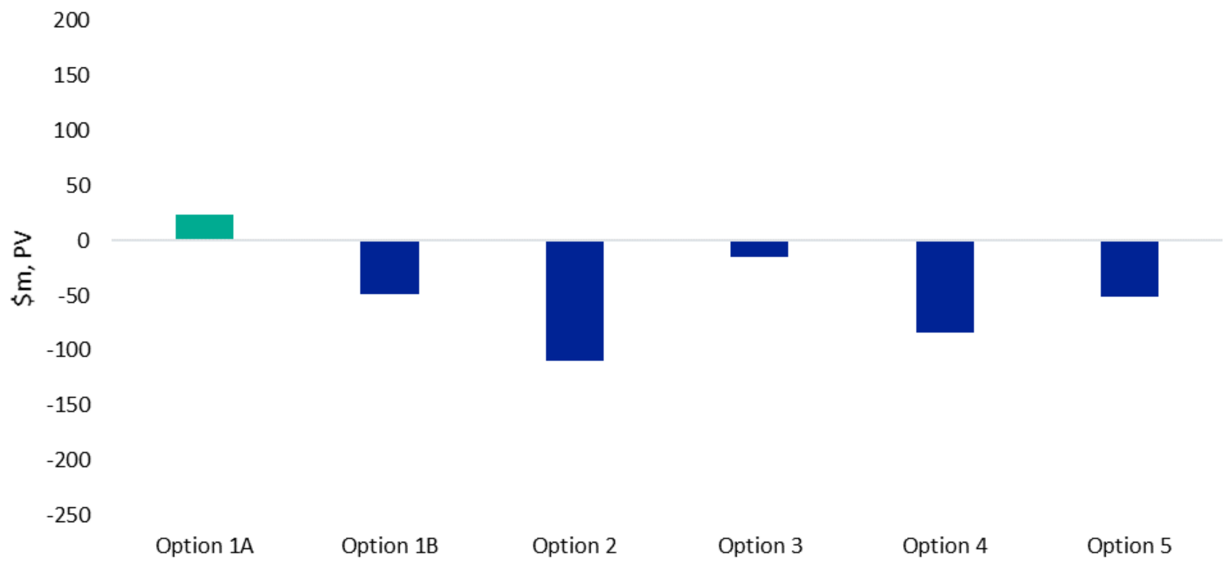
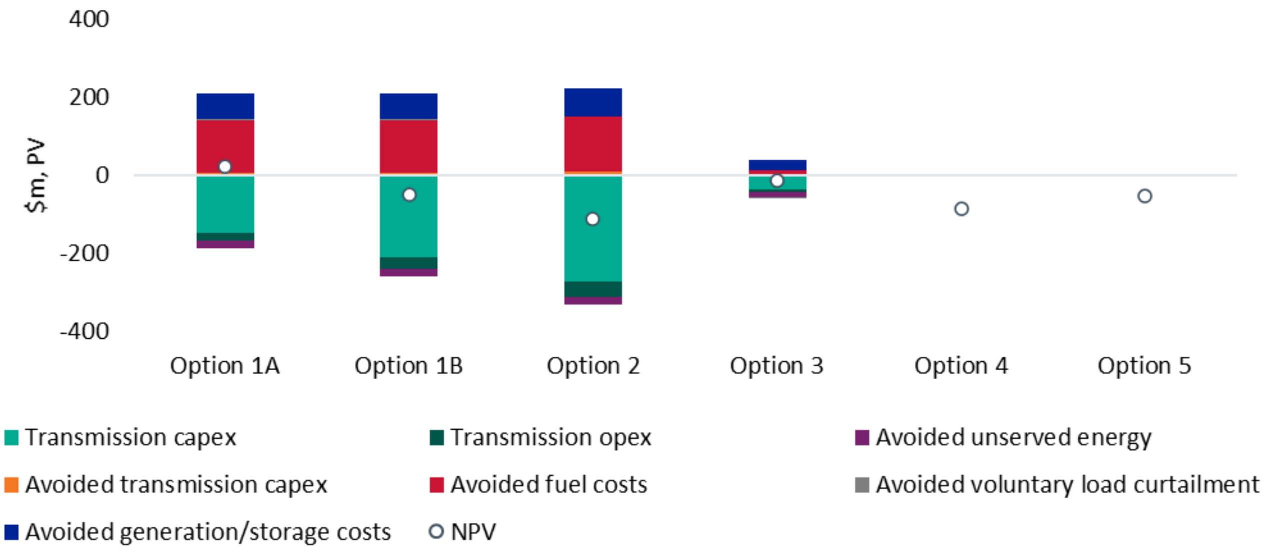


Figure 7-2 shows the composition of estimated net benefits for each option under the slow-change scenario.

Figure 7-8: Breakdown of estimated net benefits under the slow-change scenario



The wholesale market modelling for Option 1A finds that the primary sources of benefit are from lower fuel costs and avoided and deferred capex for new generators/storage. These two categories of market benefit make up approximately 96 per cent of the total estimated gross benefits for Option 1A.

The market modelling finds that these two benefits are attributable to the following:

> fuel cost savings are expected to accumulate from 2025/26 and increase throughout the assessment period:
  – the reduced fuel cost is mainly due to reduced black coal generation in the early years of the period until the late 2030s (although more brown coal generation is expected due to opening of the transfer limit from Victoria and south-western NSW to NSW load centres);
  – a small fuel cost saving from CCGT generation is also expected in the later years of the modelling;

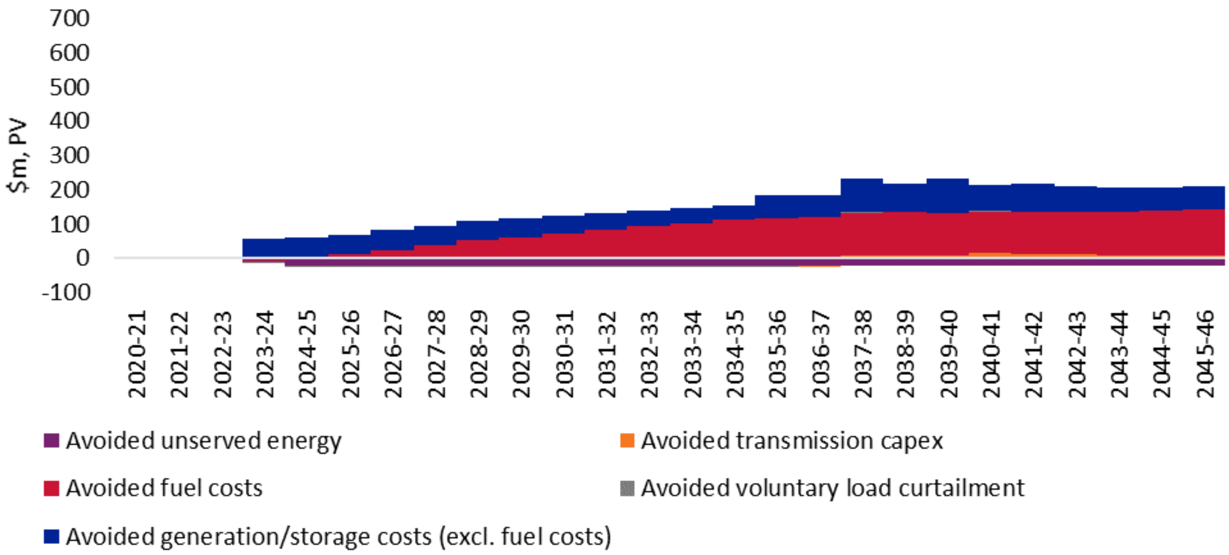
> the reduced capex is mainly due to solar generation deferral during the assessment period:
  – a capex saving is expected from 2023/24 due to approximately 40 MW of deferred solar capacity;

- from 2037/38, solar build deferral increases in addition to around 260 MW battery capacity being forecast to be deferred in the same year;
- by the last year of the assessment period, it is forecast that Option 1A will require around 110 MW more wind generation and 47 MW more OCGT, but with the avoidance of around 50 MW CCGT and 50 MW battery development overall.

While Option 2 and the battery options (i.e., Options 4 and 5) are estimated to provide the greatest level of gross benefits of all options, the greater capital cost of these options means that they all have significant net costs associated with them.

Figure 7-9 below presents the estimated cumulative expected gross benefits for Option 1A for each year of the assessment period under the step-change scenario. It shows that the majority of the overall benefits have accrued by 2037/38 under this scenario.

Figure 7-9: Breakdown of cumulative gross benefits for Option 1A under the slow-change scenario



7.4 Fast-change scenario

The fast-change scenario reflects a state of the world where there is a rapid technology-led transition of the power system and a 'fast-change' in emissions. Assumptions made in the fast-change scenario include AEMO's moderate demand forecasts (including demand-side participation), neutral gas and coal price forecasts, carbon budget, coal plants retiring earlier than the central scenario, as well as a national emissions reduction of around 52 per cent below 2005 levels by 2030.

AEMO describes the fast-change scenario as reflecting a 'rapid technology-led transformation, particularly at grid scale, where advancements in large scale technology improvements and targeted policy support reduce the economic barriers of the energy transmission. In this scenario, coordinated national and international action towards achieving emissions reductions, leading to manufacturing advancements, automation, accelerated retirement of existing generators, and integration of transport into the energy sector'.

Under these assumptions, Option 1A is estimated to deliver approximately $14 million in net benefits. This represents approximately $18 million more net benefit than the second-ranked option (Option 3), which is found to have a net cost of $4 million.

Figure 7-10 shows the overall estimated net benefit for each option under the fast-change scenario.

Figure 7-10: Summary of the estimated net benefits under the fast-change scenario

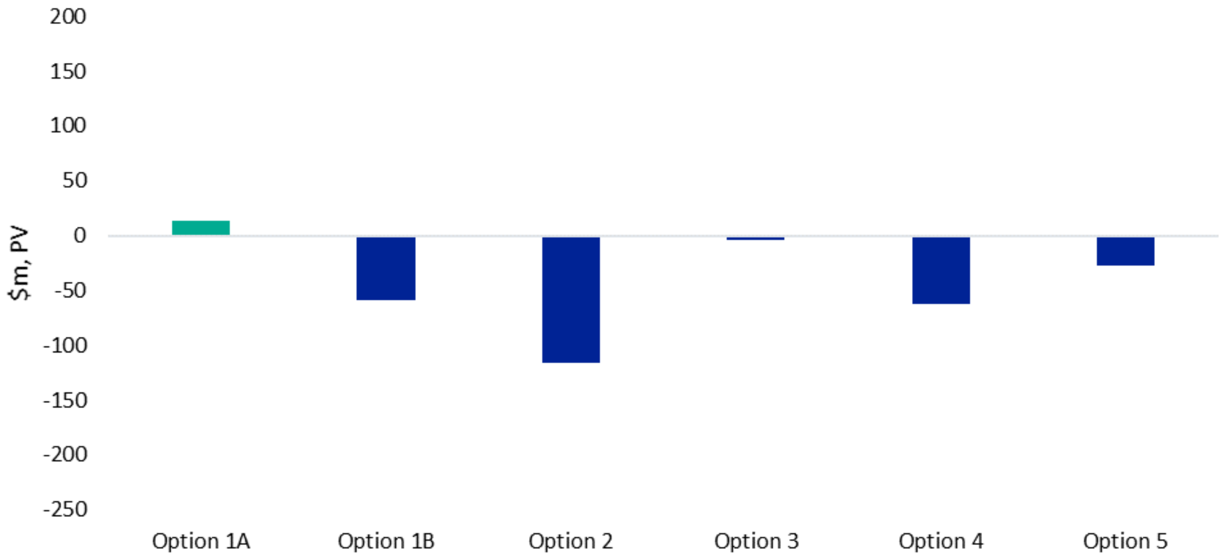
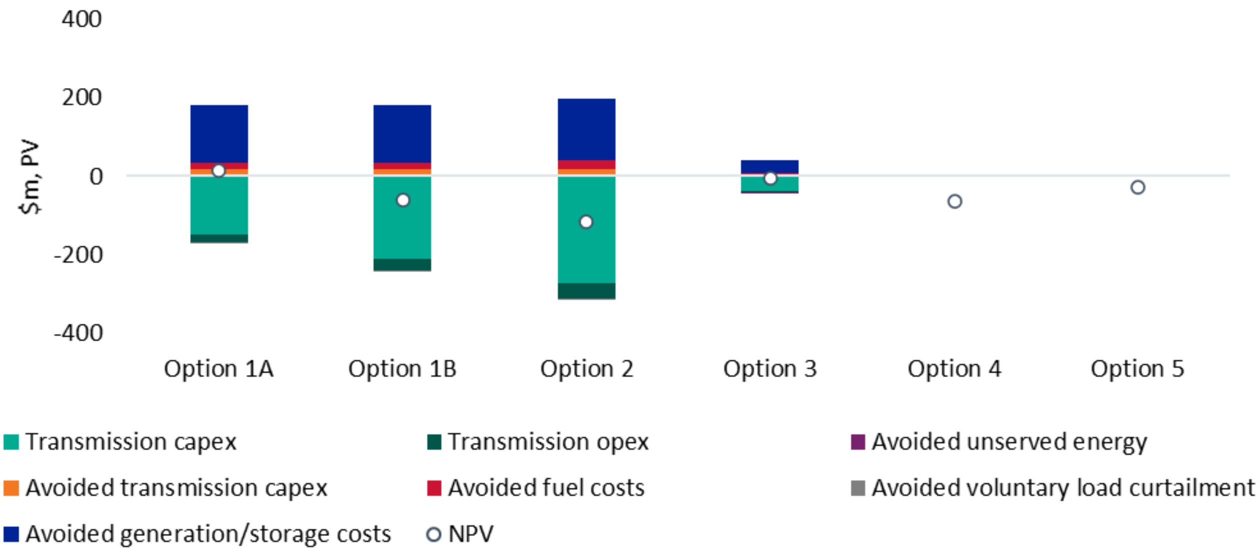


Figure 7-11 shows the composition of estimated net benefits for each option under the slow-change scenario.

Figure 7-11: Breakdown of estimated net benefits under the slow-change scenario



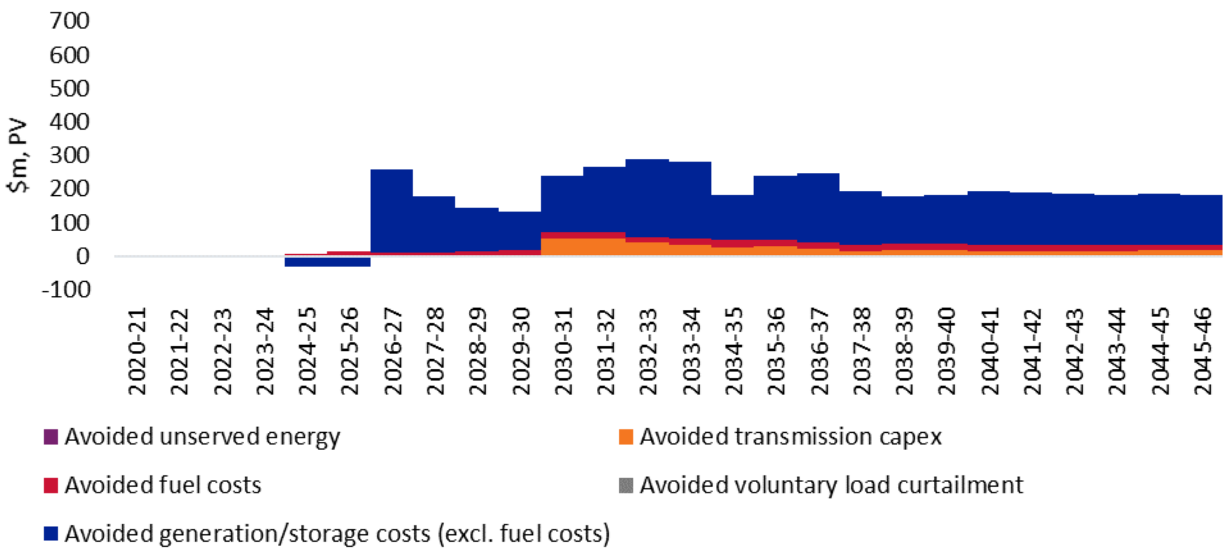
The wholesale market modelling for Option 1A finds that the primary sources of benefit are mainly from avoided and deferred capex for new generators/storage. This one category of market benefit makes up approximately 82 per cent of the total estimated gross benefits for Option 1A.

The market modelling finds that benefits from avoided and deferred capex for new generators/storage are attributable to around 330 MW of solar being deferred from 2026/27.

While Option 2 and Option 4 are estimated to provide the greater level of gross benefits than Option 1A, the greater capital cost of these options means that they all have significant net costs associated with them.

Figure 7-12 below presents the estimated cumulative expected gross benefits for Option 1A for each year of the assessment period under the fast-change scenario. It shows that the majority of the overall benefits have accrued by 2037/38 under this scenario.

Figure 7-12: Breakdown of cumulative gross benefits for Option 1A under the slow-change scenario

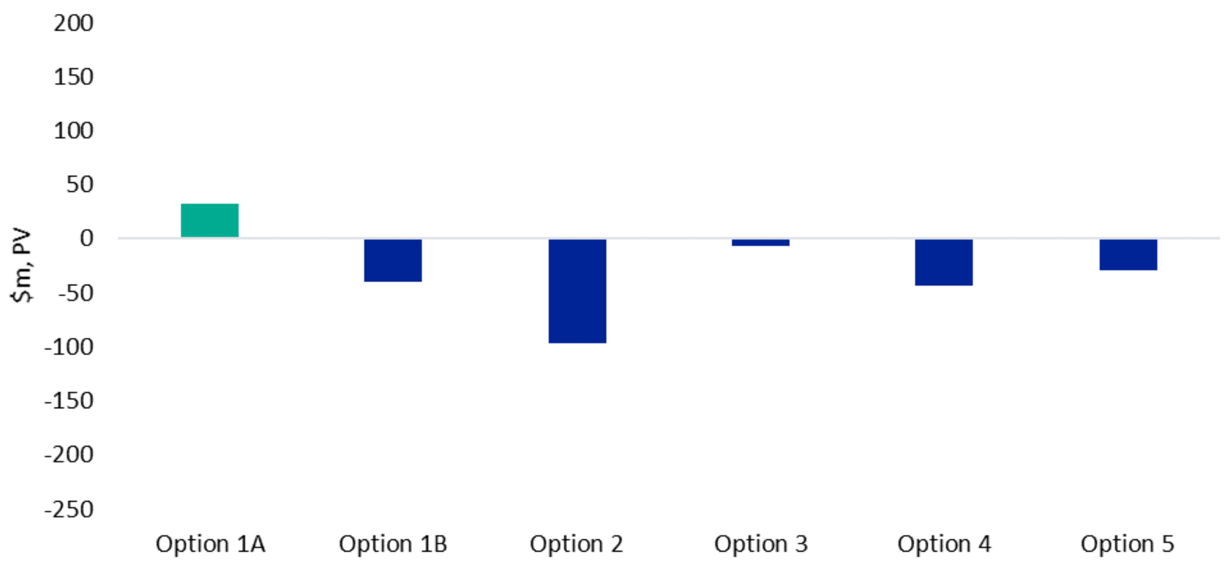


7.5 Weighted net benefits

Figure 7-13 shows the estimated net benefits for each of the credible options weighted across the four scenarios investigated (and discussed above). TransGrid has weighted each of the four scenarios equally.

Under the weighted outcome, Option 1A is found to result in an estimated net benefit of $33 million overall. Option 1A is the only option with a positive expected net benefit.

Figure 7-13: Summary of the estimated net benefits, weighted across the four scenarios



7.6 Sensitivity analysis

In addition to the scenario analysis, TransGrid has also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing. These tests all relate to the central scenario.

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

> network capital costs of the credible options;

> alternate commercial discount rate assumptions;

> increasing the weighting of the step-change scenario, in-line with recent commentary from the ESB; and
> alignment with the AEMO 2020 ISP forecasts (and AEMO's November 2020 gas price forecasts).

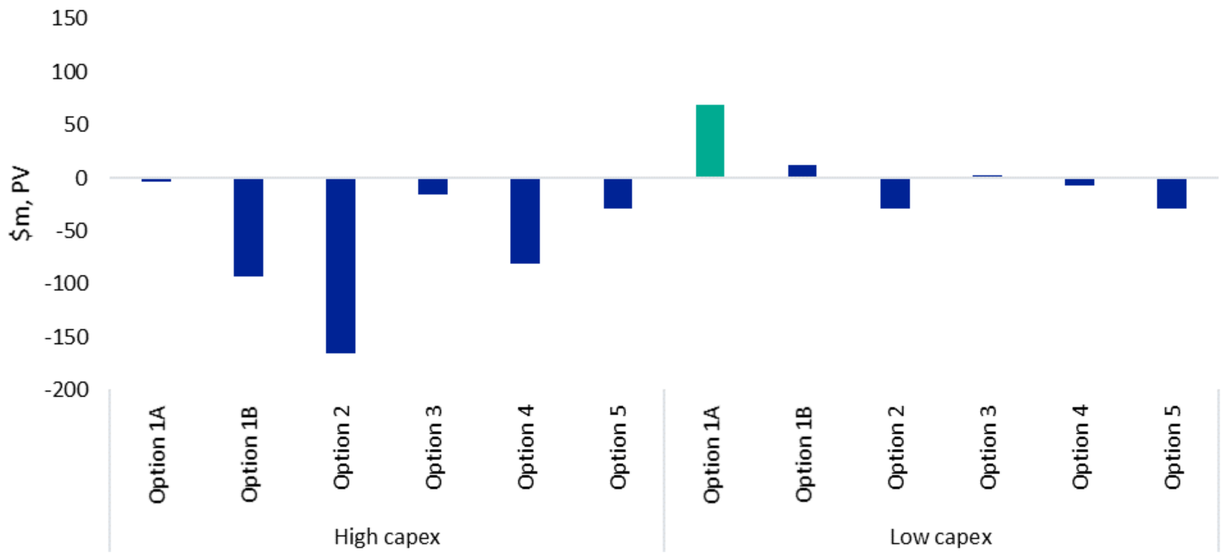
Each of the sensitivity tests undertaken in this PADR are discussed in the sections below.

7.6.1 Network capital costs of the credible options

TransGrid has tested the sensitivity of the results to the underlying network capital costs of the credible options. It is considered reasonable to expect any factors affecting the network capital costs to impact all network options equally (i.e., both the lines and STATCOM options).

Figure 7-14 shows both 25 per cent higher and 25 per cent lower assumed capital costs.

Figure 7-14: Impact of 25 per cent higher and lower network capital costs, weighted NPVs



Under the high capital cost sensitivity, all options result in net costs on a weighted basis. However, with 25 per cent lower capital costs, Option 1A, Option 1B and Option 3 are positive on a weighted basis and Option 1A is the top ranked option.

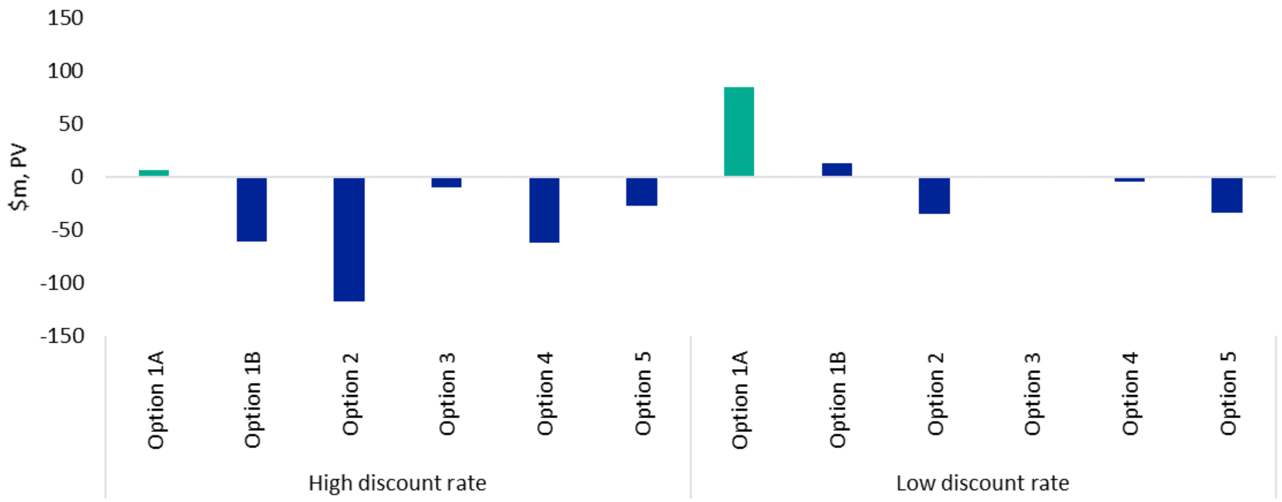
Looking at Option 1A on its own, 'boundary testing' finds that the central estimates of capital costs would need to increase by just over 22 per cent in order for Option 1A to have negative net benefits on a weighted basis. TransGrid considers that the option capital cost estimates in this PADR reflect an upper bound estimate of the expected costs and that significant increases above them are very unlikely (e.g., by more than 22 per cent). TransGrid also notes that the capital cost estimates of all options will be refined in the PACR but are not expected to be greater than 22 per cent higher than the current estimates.

7.6.2 Commercial discount rate assumptions

Figure 7-15 illustrates the sensitivity of the results to different discount rate assumptions in the NPV assessment on a weighted basis. In particular, it illustrates two tranches of net benefits estimated for each credible option – namely:

> a high discount rate of 7.90 per cent; and
> a low discount rate of 2.23 per cent.

Figure 7-15: Impact of different assumed discount rates, weighted NPVs



Under the high discount rate sensitivity, Option 1A's net benefits decrease by $16 million, or about 49 per cent, on a weighted basis compared to net benefits under a central discount rate of 5.9 per cent although Option 1A still exhibits positive net benefits under a high discount rate scenario. Under the low discount rate sensitivity, the net benefits of Option 1A increase by $52 million, or 59 per cent, compared to net benefits under a central discount rate.

'Boundary testing' finds that the discount rate would need to be greater than 11.2 per cent in order for Option 1A to have negative net benefits overall.

TransGrid notes that the AEMO's updated IASR assumptions published at the end of July include a lower central discount rate (5.5 per cent) than the 5.9 per cent assumption used in the analysis in this PADR.

7.6.3 Alternate weighting of the scenarios in-line with recent commentary

TransGrid has investigated the effects of assuming alternate scenario weightings based on more recent commentary. Specifically, and informed by recent ESB commentary that the NEM is on step-change scenario, TransGrid has increased the weighting applied to this scenario (from 25 per cent to 40 per cent) and decreased the other three scenarios equally (i.e. 20 per cent each).

TransGrid finds that the estimated net benefits of Option 1A increase by around 77 per cent under these assumed weightings and it becomes even more preferred over both the base case and the second ranked option. Under these weightings, Option 1A is found to deliver $58 million in net benefits on a weighted basis, which is approximately $61 million greater than the second-ranked option (Option 3).

7.6.4 Alignment with the AEMO final 2020 ISP assumptions

As outlined in section 5.1, the core analysis outlined above applies forecast gas prices that are lower than those adopted in the 2020 ISP. The gas price forecasts used align with those TransGrid commissioned previously in response to an inquiry made by the AER in relation to the HumeLink PADR and reflect the forecast impact on prices of the MOU between the Federal government and the NSW government in February 2020. The forecast prices are lower than those used in the 2020 ISP and are more closely aligned with AEMO's more recent gas price forecasts developed as part of its 2021 Input and Assumptions Report (IASR).

TransGrid has investigated a sensitivity that applies the AEMO gas price forecasts provided in November 2020 as part of the 2020 IASR. This scenario has been run on the central scenario and is found to have a negligible impact, reducing the estimated gross benefits by $0.09 million (0.09 per cent).

This sensitivity has been limited to the central scenario on account of the immaterial impact it has been found to have and the need to complete the PADR in a timely fashion. TransGrid considers this is a proportionate approach to the analysis and is consistent with the RIT-T.

8. Conclusion

The results of the PADR assessment find that Option 1A is expected to deliver the greatest net benefits of all investment options on a weighted basis across the four scenarios considered. Option 1A is found to deliver an estimated net benefit of approximately $33 million overall relative to the base case ‘do nothing’ option.

Option 1A is found to deliver significantly greater net benefits in the step-change scenario (in the order of $160 million) and we note that recent commentary from the ESB suggests that the NEM is in fact tracking closest to the step-change currently.[37] None of the other investment options provide a significant positive net benefit under any of the scenarios.

Option 1A involves the establishment of a greenfield transmission line between Darlington Point and the proposed Dinawan substation. Specifically, the high-level scope of this option includes:

- construct a single circuit 330 kV transmission line from Darlington Point to Dinawan (approximately 40 km); and
- install new 330 kV switchbays at Darlington Point and Dinawan substations.

The estimated capital cost of Option 1A is $211 million. Delivery is expected to take 4-5 years, with commissioning possible in 2024/25, subject to obtaining necessary environmental and development approvals.

[37] See Argus Media, Australia tops step-change energy transition scenario, Morrison, K., 7 May 2021 (accessed via https://www.argusmedia.com/en/news/2212777-australia-tops-stepchange-energy-transition-scenario on 7 July 2021) , Renew Economy, *“We are headed for step change:” ESB’s Kerry Schott on new market design,* Parkinson, G., 30 September 2020 (accessed via https://reneweconomy.com.au/we-are-headed-for-step-change-esbs-kerry-schott-on-new-market-design-89487/ on 7 July 2021) & ESB, *The Health of the National Electricity Market 2020*, Volume 1: The ESB Health of the NEM Report, 5 January 2020, p. 8.

Appendix A Compliance checklist

This section sets out a compliance checklist which demonstrates the compliance of this PADR with the requirements of clause 5.16.4 of the National Electricity Rules version 169.

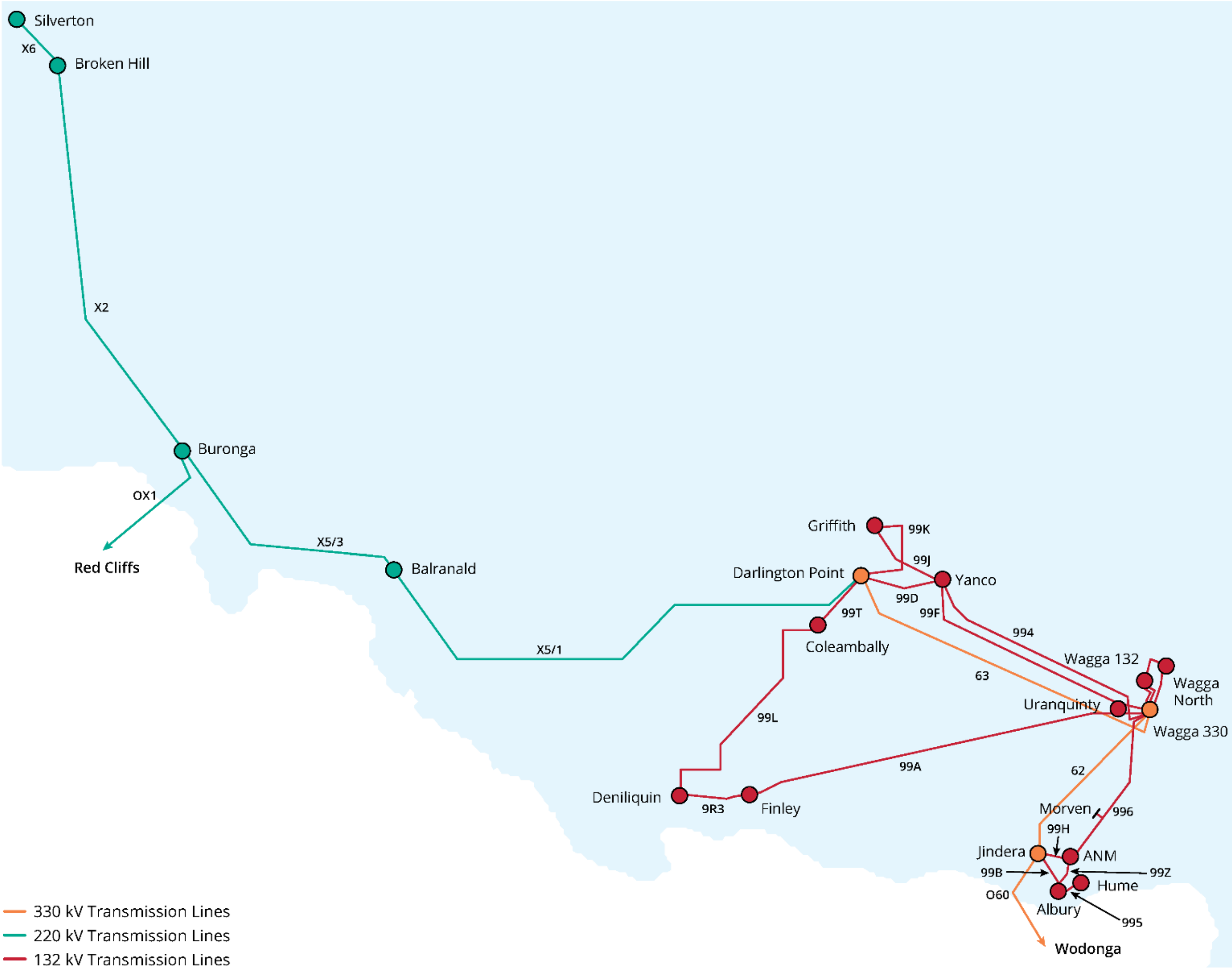
Rules clause	Summary of requirements	Relevant section(s) in the **PADR**
5.16.4(k)	A RIT-T proponent must prepare a report (the assessment draft report), which must include:	-
	(1) a description of each credible option assessed;	4
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	3
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	4 & 7
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	6
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	6
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	7
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	7
	(8) the identification of the proposed preferred option;	8
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	8

Appendix B Overview of existing electricity supply arrangements in south-western NSW

The main power system in south-western NSW consists primarily of one 330 kV transmission line from Darlington Point to Wagga Wagga (Line 63) and 220 kV transmission lines west of Darlington Point (including Line X5). Smaller underlying 132 kV transmission lines supply regional towns.

The current electricity network supplying south-western NSW is shown in Figure 8-1 below.

Figure 8-1: South-western NSW transmission network



South-western NSW has attracted a lot of interest from investors in renewable energy due to the high quality of renewable energy resources. In particular, the Broken Hill Solar Plant (53 MW) and the Silverton Wind Farm (199 MW) connected at Broken Hill in December 2015 and May 2017, respectively. More recently, new solar farms have been connected at Coleambally (150 MW) in November 2018, Griffith (29.9 MW) in April 2018, Finley (133 MW) in late 2019, and Limondale 2 (29 MW) in 2020.

Further connections are progressing with commissioning scheduled during 2021 for the Darlington Point Solar Farm (275 MW), Limondale 1 Solar Farm (220 MW), and Sunraysia Solar Farm (200 MW).

In summary, there has been approximately 594 MW of renewable generation connected in the area since December 2015 and approximately 695 MW of renewable generation is currently being commissioned.

There are two notable network developments expected in south-western NSW in coming years, namely:

> EnergyConnect, which will increase power transfer capability between South Australia, New South Wales, and Victoria by developing a new 330 kV interconnector from Robertstown in mid-north South Australia via Buronga and through to Wagga Wagga in New South Wales and includes an augmentation between Buronga in New South Wales and Red Cliffs in Victoria.
  – EnergyConnect is expected to be completed by 2024/25.[38]

> the Victoria to New South Wales Interconnector West (VNI West), which is a proposed longer-term investment to strengthen bi-directional interconnection between Victoria and New South Wales to deliver fuel cost savings, facilitate efficient connection of new renewable generation, and provide greater access to hydro energy storage plant in the Snowy Mountains.
  – The final AEMO 2020 ISP has an accelerated commissioning date of 2028/29 for VNI West (which is also in the draft 2021 IASR assumptions).[39,40]

While both of these network developments are expected to affect the development of generation in the area, they are not expected to affect the specific constraints this RIT-T is aiming to relieve. The market benefits expected from the options considered in this RIT-T have therefore been estimated as incremental to both of these major network developments (and we note that the assumed timing of VNI West affects the overall magnitude of the benefits expected from the options in this PADR).

There is a direct relationship between the new generation expected to locate in south-western NSW and how severe the effects of the new NEMDE constraint are (and so the expected market benefits from relieving it). The extent and timing of this new generation is therefore a key assumption underlying the identified need.

Table 8-1 summarises the various new generation developments expected to connect in south-western NSW.

Table 8-1: Summary of new generation developments in south-western NSW

Development	Expected timing	Size
Darlington Point Solar Farm	2021 (being commissioned)	275 MW
Limondale 1 Solar Farm	2021 (being commissioned)	220 MW
Sunraysia Solar Farm	2021 (being commissioned)	200 MW
Hillston Solar Farm	2021 (committed)	85 MW
Avonlie Solar Farm	2021 (committed)	160 MW
Additional submitted connection applications	2021-2022	Around 800 MW

38 AER, *TransGrid Contingent Project EnergyConnect*, Final Decision, May 2021, p. 1.

39 AEMO, *2020 Integrated System Plan*, July 2020, p. 82.

40 TransGrid notes that the final 2021 IASR assumptions report states that states the timing of VNI West will be an outworking of the forthcoming 2022 ISP, see: AEMO, *2021 Inputs, Assumptions and Scenarios Report*, July 2021, p. 151.

Appendix C Overview of the wholesale market modelling undertaken

As outlined in the body of this PADR, TransGrid has engaged EY to undertake the wholesale market modelling as part of this PADR.

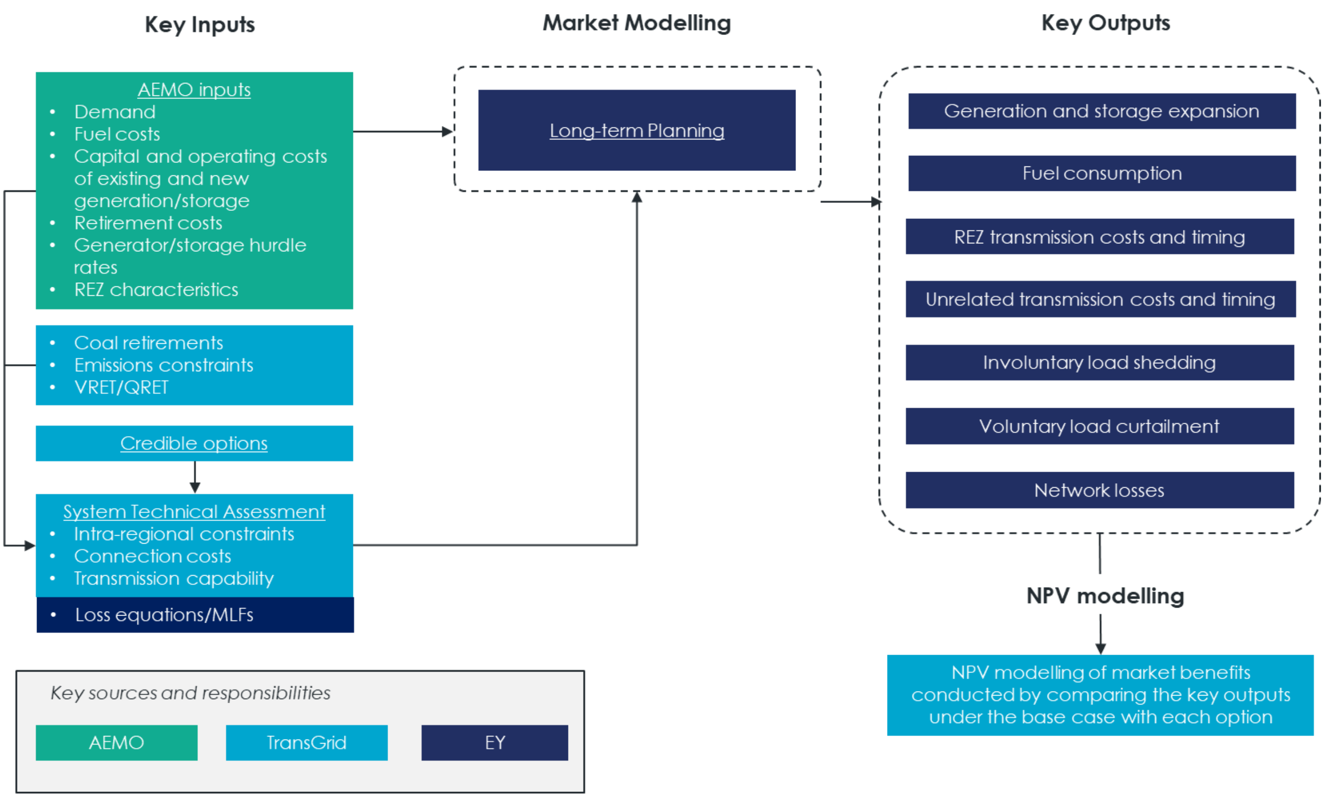
EY has applied a linear optimisation model and performed hourly, time-sequential, long-term modelling for the NEM to estimate categories of wholesale market benefits expected under the options that affect the wholesale market. Specifically, EY has undertaken market simulation exercise involving long-term investment planning, which 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. This solves for the least-cost generation and transmission infrastructure development across the assessment period while meeting energy policies.

TransGrid has 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 align with the changes to the power system under each credible option. This assessment serves as an input to the wholesale market modelling exercises EY has undertaken (as outlined above).

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

Figure C.1 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 C.1: Overview of the market modelling process and methodologies



As these modelling exercises investigate different aspects of the market simulation process, they necessarily interact and are executed iteratively using inputs and outputs.

The sub-sections below provide additional detail on the key wholesale market modelling exercises EY have undertaken as part of this PADR assessment.

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 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 is 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 emissions constraints are adhered to;
> NEM-wide and state-wide renewable energy targets are met, or else penalties are applied;
> refurbishment costs are captured;
> generator maintenance outages are scheduled to represent planned generator outages;
> regional and mainland 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 rate 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).[41]

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 sufficient to allow for generation or transmission contingences which can occur at any time, regardless of the present dispatch conditions.

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

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.

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 nine historical years ranging from 2010/11 to 2018/19.

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 nine-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region;
> the nine 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.

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 have been captured by splitting NSW into zones (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 up to 2030-31 and fed back into the Long-term Investment Planning model to capture both the impact on bids and intra-zonal losses.

Beyond 2030/31, the loss factors have been maintained at the same values as 2030-31, since network changes beyond that stage and additional renewable generation are becoming much less certain. However, this does not preclude generation investment if economic at any location.

Summary of the key assumptions feeding into the wholesale market exercise

The table below summarises the key assumptions that the market modelling exercise draws upon.

Table C-2: PADR modelled scenario's key drivers input parameters

Key drivers input parameter	Central scenario	Fast change scenario	Step change scenario	Slow change scenario
Underlying consumption	AEMO 2020 ISP Central	AEMO 2020 ISP Fast Change	AEMO 2020 ISP Step Change	AEMO 2020 ISP Slow Change

Key drivers input parameter	Central scenario	Fast change scenario	Step change scenario	Slow change scenario
New entrant capital cost for wind, solar SAT, OCGT, CCGT, pumped hydro, and large-scale batteries	AEMO 2020 ISP Central	AEMO 2020 ISP Fast Change	AEMO 2020 ISP Step Change	AEMO 2020 ISP Slow Change
Retirements of coal-fired power stations	AEMO Generation Information announced retirement date or end-of-technical-lives	Half of coal-fired power stations retire two years earlier than Central	Half of coal-fired power stations retire five years earlier than Central	Half of coal-fired power stations retire five years later than Central
Gas fuel cost	TransGrid trajectory based on Core Energy Central Upper case but NSW adjusted for lower price Narrabri gas	TransGrid trajectory based on Core Energy Central Upper case but NSW adjusted for lower price Narrabri gas	TransGrid trajectory based on Core Energy Step Change case, NSW low priced LNG to 2029, increases thereafter	TransGrid trajectory based on Core Energy Slow Change case, NSW adjusted for lower priced LNG gas to 2029, increases thereafter
Coal fuel cost	AEMO 2020 ISP Neutral	AEMO 2020 ISP Neutral	AEMO 2020 ISP Fast	AEMO 2020 ISP Slow
Federal Large-scale Renewable Energy Target (LRET)	33 TWh per annum by 2020 to 2030 (including GreenPower and ACT scheme), accounting for contribution to LRET by Western Australia (WA), Northern Territory (NT) and off grid locations			
COP21 commitment (Paris agreement)	26% reduction from 2005 by 2030			
NEM carbon budget to achieve 2050 emissions levels	N/A	AEMO 2020 ISP Fast Change budget of 2,208 Mt CO2-e to 2050	AEMO 2020 ISP Step Change budget of 1,465 Mt CO_2-e to 2050	N/A
Victoria Renewable Energy Target (VRET)	40% renewable energy by 2025 and 50% renewable energy by 2030			
Queensland Renewable Energy Target (QRET)	50% renewable energy by 2030	N/A	50% renewable energy by 2030	N/A

Key drivers input parameter	Central scenario	Fast change scenario	Step change scenario	Slow change scenario
Tasmanian Renewable Energy Target (TRET)	100% Tasmanian renewable energy generation by 2021-22		100% Tasmanian renewable energy generation by 2021-22 and 200% by 2039-40	100% Tasmanian renewable energy generation by 2021-22
South Australia Energy Transformation RIT-T	NSW to SA interconnector (EnergyConnect) is assumed commissioned from July 2024 with the scope in the 2020 Transmission Annual Planning Report and the 2020 ISP			
Western Victoria Renewable Integration RIT-T	The preferred option in the Western Victoria Renewable Integration PACR from July 2025 (220 kV upgrade in 2024 and 500 kV to Sydenham in 2025)			
Marinus Link and Battery of the Nation	1st cable: 2036	1st cable: 2031	1st cable: 2028 2nd cable: 2031	Excluded
Victoria to NSW, Interconnector Upgrades	The Victoria to NSW Interconnector upgrade PADR is assumed commissioned by July 2022. The VNI West ISP 2018 preferred option is assumed commissioned from July 2028.	The Victoria to NSW Interconnector upgrade PADR is assumed commissioned by July 2022. The VNI West ISP 2018 preferred option is assumed commissioned from July 2035.		The Victoria to NSW Interconnector upgrade PADR is assumed commissioned by July 2022. VNI West is excluded
NSW to QLD Interconnector Upgrades	The preferred option and NSW to QLD Interconnector upgrade approved option by AER are assumed commissioned by July 2022. QNI medium is assumed from 2032 and QNI large from 2035.			The preferred option and NSW to QLD Interconnector upgrade approved option by AER are assumed commissioned by July 2022. QNI medium and large are excluded.
Snowy 2.0	Snowy 2.0 is included from July 2025			
HumeLink	The HumeLink PADR preferred option (Option 3C) is assumed commissioned from July 2024			

Appendix D Summary of consultation on the PSCR

This appendix provides a summary of points raised by stakeholders during the PSCR consultation process, besides those raised by the providers of battery systems due to confidentiality.

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.

Summary of comment(s)	Submitter(s)	Our response
Support for the identified need		
Agree with the identified need outlined in the PSCR – the identified stability issues caused by outages of the 330 kV 63 Wagga to Darlington Point line are causing an abundance of renewable energy to be constrained off the market, which leads to higher prices for consumers, and severely impacts the financial viability of these generators going forward.	Neoen, p. 1 & RWE, p. 1.	See section 3.1.
Agree with the identified need and consider that if Option 1A, Option 1B or Option 2 are not approved promptly by the AER then there is a real prospect of multiple renewable energy power plants having their generation constrained or not been able to evacuate power at all for long periods and potentially leave NSW short of energy.	Reach Solar Energy, p. 2.	See section 3.1.
If action is not taken then the financial viability of the renewable projects that have already been commissioned and connected or are currently being constructed will be reduced. Potentially, and most likely, this will trigger debt financial covenants either limiting or preventing distributions to owners, further impairing the value of these projects. Without urgent actions this will be a material loss to equity. The subsequent impact on debt and equity financing as a result will make further investment in the region unlikely for a significant period of years.	Reach Solar Energy, p. 2.	Generator debt and equity considerations are not captured as a cost in the RIT-T, other than through any assumed impact on future generation investment.
If action is not taken, the frustration or stopping of additional renewable investment/ growth in the Riverina will adversely affect the regional economy of the Riverina, and reduce job creation and other business growth. Riverina landowners/ users will have less ability to diversify their income by leasing a proportion of their current farming land.	Reach Solar Energy, p. 2.	The RIT-T is a NEM-wide cost-benefit assessment and regional impacts like those identified are not captured in the analysis.
If action is not taken, this will lead to significant reduction in renewable electricity production and, substantially less than the full capacity of the new power plants.	Reach Solar Energy, p. 2.	This is captured in the wholesale market modelling. The accompanying EY market modelling report provides detail on what the lost capacity is replaced by elsewhere in the NEM under the base case.
If action is not taken, this will reduce the Riverina's contribution to provide new electricity sources in readiness for the exit of coal-fired generation from 2023 onwards both in NSW and Victoria.	Reach Solar Energy, p. 2.	The ability of the south-western region of NSW to accommodate new electricity's sources is compromised under the base case due to the constraint. Each of the options assessed seeks to relieve this and allow the region to accommodate more generation going forward.

Construction timetable of the new/rebuild line options		
Concerned that the 4-5 year expected construction timetable is ambitious.	RWE, p. 2 & solar generator (confidentiality requested), p. 1.	See section 3.2.
Consider the programme for Option 2 in the PSCR (4-5 years) is very conservative and discussions with technical advisors/contractors suggest 12 months to design, build and commission a 160km 330kV single circuit transmission line is more accurate.	Reach Solar Energy, p. 3.	See section 3.2.
Options 1A and 1B require a connection between Darlington Point and a new sub-station called Dinawan (which is to be built as part of PEC). If EnergyConnect is delayed, then the RIT-T solution is also delayed. The acquisition of these easements will take considerable time and come at a significant cost over utilizing the existing corridor under Option 2.	Reach Solar Energy, p. 3.	See section 3.2.
Would like to explore the possibility of expediting the RIT-T process.	Sunraysia Solar Farm, p. 1, RWE, p. 2, Reach Solar Energy, p. 4 & solar generator, p. 2.	See section 3.2.
The option with the shortest lead and execution times would be the best.	Neoen, p. 1.	TransGrid is progressing the RIT-T as quickly as possible, while allowing adequate time to comprehensively liaise with stakeholders and assess all options available, including those proposed in submissions. The RIT-T process, and the post-RIT-T process, have well-codified timeframes for consultation set-out in the NER and we are not able to expedite these processes beyond the NER requirements. Overall, the option with the greatest estimated net benefits will be preferred.
The constraint imposed is likely to cause very material constraints on new renewable generation power plant until the RIT-T solution is implemented and strongly urge this matter be addressed on an urgent basis.	Reach Solar Energy, p. 2.	
The ability of interim solutions to assist		
Interested in exploring possible interim solutions that can provide relief in the short and medium term, while a longer term solution is worked out through the RIT-T.	Sunraysia Solar Farm, p. 1, RWE, p. 2 & solar generator, p. 2.	See section 3.2.
The use of STATCOMs		
Consultation with technical advisors has resulted in Option 3 being considered an incomplete and inadequate solution.	Reach Solar Energy, p. 4.	See section 3.5.

Encourages TransGrid to explore the option of a D-VAR type STATCOM, which tend to operate more quickly than traditional STATCOMs and may show that the constraint can be fully alleviated rather than only partially.	Neoen, pp. 1-2.	See section 3.5.
Other comments		
Consider Option 2 is already 'actionable' in accordance with the Energy Security Board ruling on 27 March 2020, because the EnergyConnect route via Darlington Point and Wagga Wagga was included in the past two ISP's as a Group 1 priority.	Reach Solar Energy, p. 2.	EnergyConnect does not include the network componentry of Option 2 in this RIT-T. EnergyConnect is the 'actionable ISP project' under the NER, and components not being progressed as part of EnergyConnect do not qualify for 'actionable' status on a stand-alone basis.
Option 1A and Option 1B both appear feasible but are likely to require material new easements through high-value, irrigated land.	Reach Solar Energy, p. 4.	The costs of acquiring the easements required for each option has been estimated as part of the updated costs presented in this PADR.
The 2018-2023 review period submitted by TransGrid, and approved by the AER, flagged a contingent project was required to support the South West section of NSW for renewables.	Reach Solar Energy, p. 3.	The project is a contingent project but one of the trigger events is the successful application of the RIT-T.
There is likely to be a material increase in net market benefit to the NEM under Option 2 as it enables low cost renewable generation to the NEM in readiness for the exit or breakdown of coal generation. It also reduces the linkage that NSW electricity prices has with cyclical global thermal coal, oil and LNG commodity prices.	Reach Solar Energy, p. 3.	The net benefit of Option 2 has been directly modelled in this PADR and is found to have significantly negative net benefits in all scenarios investigated.
Option 2 follows an existing 330kV circuit and offers the use of existing easements for the majority of the route thereby reducing any additional loss of potentially viable farming land.	Reach Solar Energy, p. 3.	The cost of acquiring the easements has been reflected in the costing for each option.
Option 2 is preferred due to it having known topography and ground conditions.	Reach Solar Energy, p. 3.	TransGrid notes that the topography and ground conditions of each option feed into its costs.
Option 2 is preferred due to it having synergies in operating and maintenance costs with a new 330kV transmission line alongside an existing circuit.	Reach Solar Energy, p. 3.	Any synergies are not expected to be material to the overall assessment due to the capital cost differences.
Option 2 is preferred as it provides additional non-monetised benefits such as renewables integration and system security. It also enables sharing of energy between NSW, SA and Victoria.	Reach Solar Energy, p. 3.	Non-monetised benefits are not able to be captured in the RIT-T assessment. All options assessed are considered to enable the sharing of energy between NSW and the rest of the NEM relative to the base case.

Appendix E The RIT-T process explained

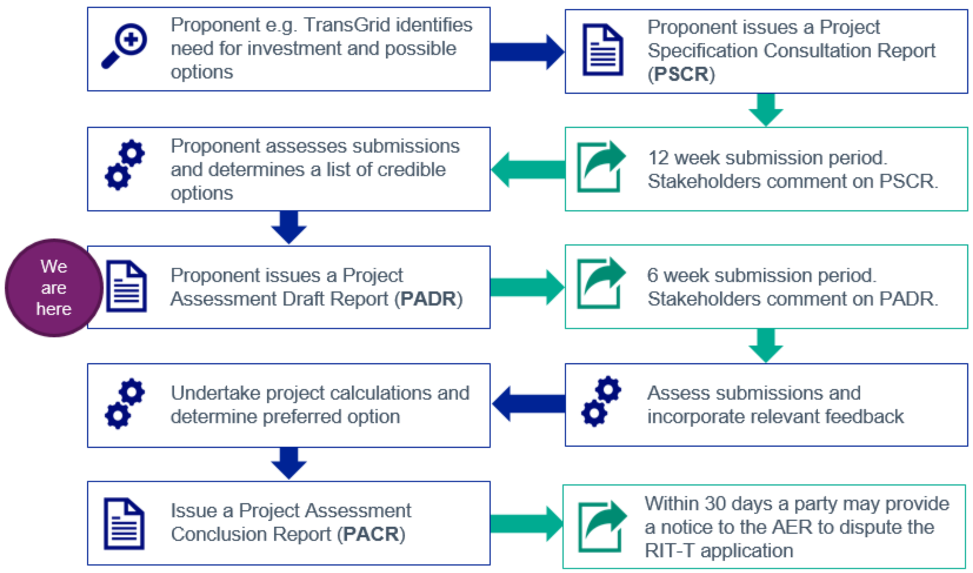
This information has been designed to assist stakeholders who are unfamiliar with the RIT-T process and would like to understand how it fits into the planning process.

What is the RIT-T process?
The RIT-T is a cost-benefit analysis which TransGrid and other transmission network service providers must undertake to test the economic viability of different options available to meet some future transmission demand. It is designed to provide options that will deliver the highest net economic benefits to all those who produce, consume and transport electricity in the market, whilst meeting supply reliability standards.

Why is a RIT-T process followed?
The TransGrid network is a natural monopoly with no direct competitors. The AER regulates electricity networks like TransGrid by setting the maximum amount of revenue they can earn from electricity users. The RIT-T approach is ultimately intended to protect consumers from paying more than is necessary for their electricity in the long term, while still benefitting from a safe and reliable electricity supply. It ensures the recommended solution is the most economic option to meet reliability standards.

What is involved in the RIT-T process?
The process is essentially a staged approach whereby different options are tested against a set of economic criteria. At different stages of the process, stakeholders are invited to make submissions to outline any concerns, or to support a particular option(s). These submissions are considered by TransGrid and may influence whether the next step in the process is followed.

Below: The RIT-T process for *Improving stability in south-western NSW*.



1. **PSCR** seeks feedback and advice on the identified need for new transmission infrastructure
2. **PADR** identifies and seeks feedback on the preferred infrastructure investment options
3. **PACR** presents the recommended solution to deliver the highest net economic benefit and intended course of action

When does TransGrid engage stakeholders during the RIT-T process?

While TransGrid welcomes submissions from all interested parties in relation to proposals during submissions periods, we consult with interested parties in accordance with the relevant National Electricity Rules, AER guidelines and our own engagement policies and procedures. The consultation is designed to:

> inform stakeholders of the investment need and proposed options to address it
> test the market for alternative and more efficient solutions
> explain to stakeholders the basis on which the preferred option has been selected

The level of engagement is decided on a case-by case basis and may involve, but not be limited to engaging:

> government representatives
> councils
> peak industry bodies
> TransGrid Advisory Council members
> government departments
> landholders

Does a preferred option outlined in an RIT-T process mean the project will be built?

Not necessarily. A preferred option identified through the RIT-T process shows the most ideal option based on providing least-cost, secure and reliable energy. It does not take into account other factors such as land use, the environment or other social considerations.

When would land use, the environment and other social factors be considered?

Once a preferred option has been found through the RIT-T process, planning and building such infrastructure would be subject to obtaining any necessary environmental and development approvals. This may involve submission of an Environmental Impact Statement (EIS) to the NSW Department of Planning Industry and Environment, whereby the environmental, social, economic and other impacts of a proposed project are outlined, as well as measures designed to mitigate those impacts. Community and stakeholder feedback would be required and considered as part of the EIS assessment process. In some cases the preferred option may be amended based on environmental factors and stakeholder and community feedback.

When can I find out more information?

If you would like further information on the RIT-T process please email us at community@transgrid.com.au .