Improving stability in South-Western NSW

RIT-T - Project Assessment Conclusions Report

Region: South Western New South Wales

Date of issue: 15 June 2022

People. Power. Possibilities.

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Executive summary

South-western New South Wales (NSW) has seen significant growth in renewable generation connections to the transmission network as part of the wider energy market transition. More than 790 MW of renewable generation has connected in South-western NSW since December 2015 and approximately 580 MW of renewable generation is currently in the process of being commissioned.

This new generation is having an impact on how this part of the power system operates, with the resultant changes in power flows leading to an increasing risk of system instability going forward. This resulted in the Australian Energy Market Operator (AEMO) introducing an operational constraint in the NEM Dispatch Engine (NEMDE) in May 2020 to limit power flows, in order to manage the risks to system stability.[1]

We have identified the opportunity to strengthen the transmission network in south-western NSW to relieve this constraint and provide market benefits to the National Electricity Market (NEM).

This Regulatory Investment Test for Transmission (RIT-T) process was initiated to progress and consult on the assessment of investment options and whether the market benefits outweigh the costs of the investments. Publication of this Project Assessment Conclusions Report (PACR) is the final formal document in the RIT-T process and follows the Project Assessment Draft Report (PADR) released in September 2021.

Overview

The PACR finds that a new Darlington Point to Dinawan 330 kV transmission line coupled with an interim 3-year network support contract with a battery energy storage system (BESS) solution ('Option 4') is the preferred option for meeting the identified need across all scenarios and sensitivities assessed. Option 4 is expected to deliver approximately $91 million in net benefits over the 27 year assessment period (on a weighted-basis).

The BESS is being developed by Edify and is expected to provide network support from 2023/24 to 2025/26 (when the new line is expected to be commissioned).

Option 4 is expected to provide net benefits to consumers and producers of electricity and to support energy market transition by allowing for more efficient sharing of generation across the NEM through relieving the current constraint in south-western NSW. The market modelling finds that this defers, or avoids, significant costs associated with the construction of new, more expensive generation and/or storage capacity in the NEM in all three scenarios assessed in this PACR. Under the progressive change scenario, although the benefit of this avoided/deferred investment is lower, the option also provides significant avoided fuel costs in the NEM through avoiding the use of higher cost generators to meet demand.

The estimated capital costs of the network elements of Option 4 are $166.9 million. The proposed annual network support cost (opex) is $3.25 million/year for the three years of support. The network support component has no incremental capital costs compared to the base case (since the BESS that will provide the network support is currently being developed independently and is considered 'committed').

While the ability of the BESS component to relieve the constraint still requires full technical feasibility to be confirmed and agreed with AEMO, we consider Option 4 a 'no regrets' option at this stage.

[1] This constraint was updated on 1 December 2021 following the commissioning of a proponent-funded temporary special protection scheme (SPS) in the area.

Specifically, should the BESS ultimately not be considered able to address the constraint, or not be able to provide network support ahead of the new line being commissioned, Option 1A (the new Darlington Point to Dinawan 330 kV transmission line alone) will be considered the preferred option and will proceed on the same timeframe. Option 1A is the second-ranked option in the PACR assessment, and also has significantly positive net benefits, across all three scenarios assessed.

Both Option 4 and Option 1A are expected to generate sufficient benefits to recover their costs within five years of commissioning the new line in the step-change and hydrogen superpower scenarios, and within 11 years in the progressive change scenario.

This RIT-T also considered a brownfield option (Option 1B) to rebuild existing transmission lines.[2] As noted, the outcome of the RIT-T is that Option 4, which involves a greenfield lines component (i.e. Option 1A), has the highest net market benefits. Despite this, we note that the brownfield option (Option 1B) is more consistent with Transgrid's overall general preference for brownfield investments.

Importantly, for greenfield transmission line investments, the RIT-T does not address line route specifics for the preferred option.[3] These are scoped by the TNSP and assessed within the Environmental Impact Statement (EIS). Planning approval would only be granted by the NSW Minister for Planning and Public Spaces following extensive, genuine community and stakeholder consultation and demonstration that environmental impacts can be effectively managed or mitigated. This process will commence following the conclusion of this RIT-T.

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

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 (the 330 kV transmission line from Darlington Point to Wagga Wagga), including thermal overloads and under-voltage. These issues are being driven by the increased levels of renewable generation in the area.

If action is not taken, the 132 kV system will 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 cascading generator outages and further stability issues.

Based on our advice, AEMO implemented a new system normal constraint in the NEMDE on 8 May 2020 to limit power flows on Line 63, which was updated on 1 December 2021 following the commissioning of a proponent-funded temporary special protection scheme (SPS). 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.

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. Power flows east from existing generation in south-western NSW presently peak at more than 790 MW and a further 580 MW of generation is due to be

[2] 99T Darlington Point to Coleambally and 99L Coleambally to Deniliquin as 330 kV to Dinawan

[3] Instead, the RIT-T approval process reviews, and publicly consults on, a TNSP's application for new investment to meet an identified need. Overall, it identifies the technical solution to the need that provides the greatest net benefit to the NEM overall. This RIT-T process is undertaken in consultation with consumers, AEMO, Registered Participants and other interested parties regarding the investment options under consideration.

commissioned in south-western NSW in 2021-22. This has resulted in material constraints to some generators in the region.

Many of the submitters to the PADR highlighted the impact of the constraint on generation in the NEM. All of the existing or new renewable generators in south-western NSW that submitted to the PADR commented on the impact of the constraint.

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.

Key developments since the PADR have been reflected in the PACR

There have been a number of key developments since the PADR was released in September 2021 that have affected the analysis in this PACR. Namely:

- the draft 2022 ISP being published in December 2021;
- early closures announced for coal power plants;
- a change in the statuses of the two non-network proposals assessed in the PADR, including the BESS in the preferred option (Option 4) now being considered 'committed' under the RIT-T;
- additional renewable generation connections (actual and planned) in the area; and
- a proponent in the area funding and commissioning a temporary SPS.

Each of these has been carefully considered and reflected, where relevant, in the PACR assessment.

In addition, we received submissions from six parties on the PADR, which can be grouped as follows:

- existing or new renewable generators in south-western NSW – Darlington Point Solar Farm, RWE Renewables Australia, Reach Solar Energy Co, Iberdrola Australia and one party who wished to remain confidential; and
- the Public Interest Advocacy Centre (PIAC).

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

- support for the identified need;
- current cost recovery arrangements;
- feasibility of BESS options;
- support for interim solutions;
- comments on the scenario analysis;
- future proofing the options; and
- the RIT-T timeframes and construction timetable.

The key matters raised in submissions relevant to the RIT-T assessment are summarised in this PACR, together with our responses and how the matters raised have been reflected in the assessment.

The PACR assessment covers six different credible options

The table below summarises the credible options assessed in this PACR.

Table E-1: Summary of the credible options

Option	Description	Estimated capital cost*	Expected commissioning year
1A	Establish a new Darlington Point to Dinawan 330 kV transmission line	$166.9 million	2025/26
1B	Rebuild the existing 99T Darlington Point to Coleambally and 99L Coleambally to Deniliquin as 330 kV to Dinawan	$222.2 million	2025/26
2	Establish a new Wagga Wagga to Darlington Point 330 kV transmission line	$285.4 million	2026/27
3	STATCOM (100 MVar)	$33.2 million	2025/26
4	Option 1A + 3-year interim network support solution utilising a BESS (proposed by Edify)	$166.9 million for the network component The network support component has no incremental capital costs compared to the base case (since it is considered 'committed'). The proposed annual network support cost (opex) is $3.25 million/year for the three years of support.	2025/26 for the network component 2023/24 for the network support from the BESS
5	A standalone long-term BESS solution (network owned)	$216.0m (initial) $102.1m (reinvestment)	2024/25 (initial) 2044/45 (reinvestment)

** While the capital costs are shown at an aggregate level in this table, they have been broken out by key cost category for each option in the body of this PACR, i.e., substation works, line works, property/land access/easement costs and battery costs (where relevant).*

Option 4 involves the use of an interim BESS that was proposed by a third-party (Edify) in response to the PSCR. Edify would be the owner of the BESS under this option and would be paid a network support payment. We note that, since the PADR was released, the BESS component of this option (which is being independently developed) has now been confirmed as meeting the criteria for a 'committed' investment.

The PADR also included a third-party owned stand-alone BESS solution (Option 5). While the proponent for this solution has since withdrawn their offer, the PACR continues to assess a stand-alone BESS solution for completeness but now assumes that it would be Transgrid-owned. The cost, build time and operating characteristics of this option are based on our internal database for such solutions and do not draw on what was proposed by the original proponent of this option.

The capital costs for all options have been revised since the PADR to take account of current market trends and risks, drawing on the experience of recent projects as well as a detailed review of the scope of each option. The revised costs in this PACR are consequently lower than in the PADR as a result of this process.

Three scenarios have been assessed

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 three scenarios as part of this PACR assessment, which differ in terms of the key drivers of the estimated net market benefits. These scenarios have been updated since the PADR. Specifically, we have now modelled the market benefits of each of the options across each of the following three 2022 ISP scenarios, which we have then weighted based on the relative weightings proposed in the draft 2022 ISP:[4]

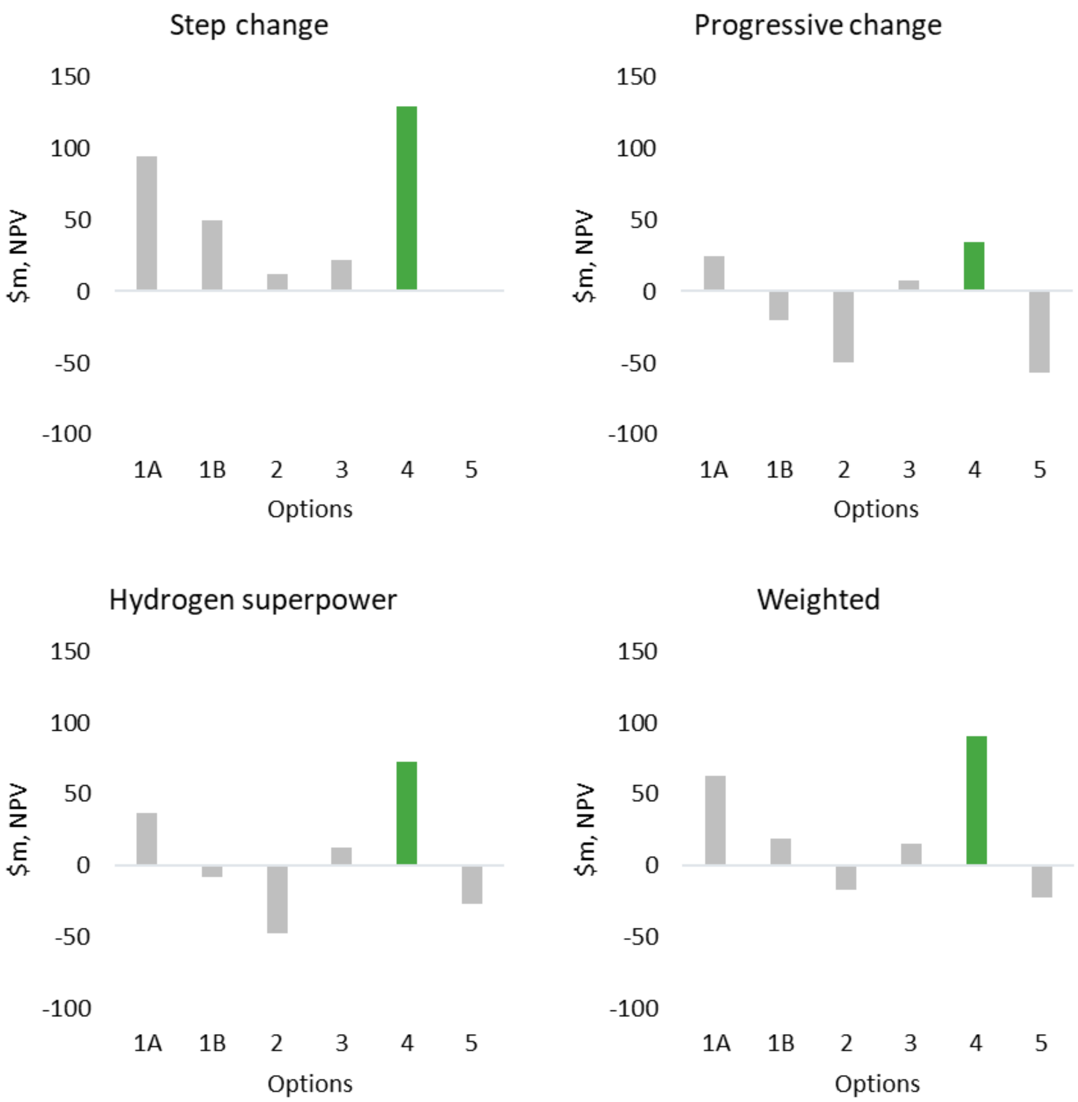
- step-change (52 per cent weighting);
- progressive change (30 per cent); and
- hydrogen superpower (18 per cent).

Option 4 is found to be the preferred option across all scenarios and sensitivities investigated

The PACR assessment finds that a new Darlington Point to Dinawan 330 kV transmission line coupled with an interim 3-year BESS solution ('Option 4') is the preferred option for meeting the identified need across all three scenarios assessed. Option 4 is expected to deliver approximately $91 million in net benefits over the 27 year assessment period (on a weighted-basis).

[4] Specifically, we have given each scenario a weighting based on the proportion its weighting in the draft 2022 ISP makes up of the cumulative weight given to these three scenarios (as outlined in section 5.1).

Figure E-1: Estimated net benefits for each scenario



Option 1A, which is the new Darlington Point to Dinawan 330 kV transmission line alone (without the interim BESS component) is the second-ranked option in the PACR assessment, and also has significantly positive net benefits, across all three scenarios assessed.

The vast majority of the estimated market benefits for the options in each scenario comes from their ability to defer, or avoid, significant costs associated with the construction of new, more expensive generation and/or storage capacity in the NEM. Under the progressive change scenario, although the benefit of this avoided/deferred investment is lower, the options also provide significant avoided fuel costs in the NEM through avoiding the use of higher cost generators to meet demand.

We have also tested the robustness of the conclusion that Option 4 is the preferred option to a range of sensitivities as part of this PACR – namely:

- the impact of the temporary SPS funded by a proponent in the area;
- changes in the capital costs of the credible options; and

- alternate commercial discount rate assumptions.

Each sensitivity confirms Option 4 as the preferred option under this RIT-T.

In terms of capital costs, we find that they would need to increase by approximately 79 per cent in order for Option 4 to have negative expected net benefits, and by 55 per cent for Option 1A to have a negative net benefit. There is no realistic capital cost change that would result in Option 1B (the third-ranked option) being ranked equally with either Option 4 or Option 1A.

If future cost estimates do increase materially, we would reassess the NPV analysis in light of this change and the thresholds set out above, to identify whether it would constitute a 'material change in circumstances' (i.e., under clause 5.16.4(z3) of the NER) that would trigger re-application of the RIT-T.

We note that the ability of the BESS component to relieve the constraint under Option 4 still requires full technical feasibility to be confirmed and agreed with AEMO, as well as a network support contract to be negotiated and agreed between Edify and Transgrid. However, we consider Option 4 a 'no regrets' option at this stage. Specifically, should the BESS not be considered able to address the constraint, ahead of the new line being commissioned, Option 1A (which is the new Darlington Point to Dinawan 330 kV transmission line alone) will be considered the preferred option, and would proceed on the same timeline as it would as a component of Option 4.

Further information and next steps

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

We are now in the midst of the pre-investment activities necessary to proceed with the preferred option.

Our current revenue determination has a contingent project for this RIT-T (the 'support south western NSW for renewables' contingent project). A key next step is therefore to submit a contingent project application to the AER once all triggers have been met. The application process will determine the required expenditure to be added to Transgrid's revenue requirement in the next regulatory period.

We will also continue to perform technical analysis to confirm the ability of the BESS to increase the transfer limits, as assumed in this PACR, which is expected to be completed by September 2022. Following this analysis, Transgrid will liaise with AEMO to agree on the transfer limits with the BESS assumed to be in-place, which is expected to be completed by December 2022. Successful completion of these two stages will allow Transgrid to proceed to signing a network support contract with Edify.

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

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1. Introduction

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 Conclusions Report (PACR) has been prepared as the final formal document in the RIT-T process and follows the Project Assessment Draft Report (PADR) released in September 2021.

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. More than 790 MW of renewable generation has connected in the area since December 2015 and approximately 580 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 flow has reversed 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 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 power system stability, the Australian Energy Market Operator (AEMO) implemented an operational constraint in the NEM Dispatch Engine (NEMDE) in May 2020 to limit power flows and prevent this occurring.[5] This constraint was updated on 1 December 2021 following the commissioning of a proponent-funded temporary special protection scheme (SPS) in the area.

Prior to the 1 December 2021 update, the constraint bound for 12,263 dispatch intervals (1,021 hours) over the course of 2021 and, after the 1 December 2021 update, the updated constraint bound for 821 dispatch intervals (68 hours) in the two months to 1 February 2022.

We have 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 was 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 do not form an 'actionable ISP project' as part of AEMO's final 2020 Integrated System Plan (ISP), or AEMO's recent draft 2022 ISP, and so are being progressed outside of the ISP framework.

Our 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

[5] We note 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 alleviated following commissioning of EnergyConnect in 2024-25. See: https://www.aemo.com.au/market-notices?marketNoticeQuery=&marketNoticeFacets=RECALL+GEN+CAPACITY%2CCONSTRAINTS

the contingent project is successful completion of a RIT-T.[6] Our Revenue Proposal for the forthcoming 2023-2028 regulatory period also includes this contingent project (now referred to as 'improving stability in south western NSW'), and continues to include the successful completion of a RIT-T as one of the trigger events.[7]

The findings of this PACR align with the NSW Electricity Infrastructure Roadmap,[8] 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 Renewable Energy Zone (REZ) (i.e., 'N5' in the draft 2022 ISP).[9]

We note that the current constraint is impacting existing and planned generators in the area, and that stakeholders have expressed their support for this RIT-T process to be progressed swiftly. However, it is important to ensure that the outcome is robust and reflects the latest externally consulted on assumptions regarding the development of the NEM. We have therefore aligned the assessment in this PACR with the assumptions adopted in AEMO's draft ISP released in December 2021.

1.1. Purpose

The purpose of this PACR 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 PADR and highlight how these have been addressed in the RIT-T analysis;
- describe the options that have been assessed under this RIT-T, including how these have been shaped as part of the consultation process;
- present the results of the updated 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 overall preferred option of the RIT-T, i.e., the option that is expected to maximise net market benefits.

Overall, a key purpose of this PACR is to provide interested stakeholders the opportunity to review the analysis and assumptions and have certainty and confidence that the preferred option has been robustly identified as optimal.

We are also releasing supplementary reports on our website to complement this PACR. Detailed cost benefit results are included as a spreadsheet appendix accompanying this report.

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 Transgrid, *Revenue Proposal 2023-28*, 31 January 2022, pp. 164-165.

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

9 On 25 March 2022, the NSW Government finalised the draft declaration of the South-West NSW REZ for public exhibition. The declaration is the first step in formalising the REZ under the *Electricity Infrastructure Investment Act 2020* and sets out the intended network capacity (size), geographical area (location) and infrastructure that will make up the REZ. See: https://www.energy.nsw.gov.au/renewables/renewable-energy-zones/south-west-renewable-energy-zone-draft-declaration

1.2. Further information and next steps

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

We are now in the midst of the pre-investment activities necessary to proceed with the preferred option.

Our current revenue determination has a contingent project for this RIT-T (the 'support south western NSW for renewables' contingent project). A key next step is therefore to submit a contingent project application to the AER once all triggers have been met. The application process will determine the required expenditure to be added to Transgrid's revenue requirement in the next regulatory period.[10]

We will also continue to perform technical analysis to confirm the ability of the BESS to increase the transfer limits, as assumed in this PACR, which is expected to be completed by September 2022. Following this analysis, Transgrid will liaise with AEMO to agree on the transfer limits with the BESS assumed to be in-place, which is expected to be completed by December 2022. Successful completion of these two stages will allow Transgrid to proceed to signing a network support contract with Edify.

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

[10] Under NER 6A.8.2(n) if a TNSP submits a contingent project application in the final year of a regulatory control period or during the last 90 business days of the penultimate year of a regulatory control period the adjustment to revenues is made in the subsequent regulatory period.

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 PACR for improving the stability of the south-western NSW power system. It first summarises a number of key developments since the PADR was released and how they have been reflected in this PACR. It then re-summarises the 'identified need' for this RIT-T from the PSCR/PADR, as well as 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. Developments since the PADR was released in September 2021

There have been a number of key developments since the PADR was released that have affected the analysis in this PACR – namely:

- the draft 2022 ISP being published in December 2021;
- early closures announced for coal power plants;
- a change in the statuses of the two non-network proposals assessed in the PADR;
- additional renewable generation connections (actual and planned) in the area; and
- a proponent in the area funding and commissioning a temporary SPS.

Each of these is summarised in the subsections below.

2.1.1. The draft 2022 ISP was published in December 2021

Four core scenarios were considered as part of the PADR, which were designed to cover a wide range of possible futures and were generally aligned with the AEMO 2020 ISP 'central', 'slow-change', 'step-change' and 'fast-change' scenarios.

Since then, AEMO released the draft 2022 ISP in December 2021, which included a different set of scenarios, underlying assumptions and optimal development path (ODP). The credible options in this PACR have been assessed in line with these developments and the market modelling has now been undertaken for each of the following three 2022 ISP scenarios:

- step-change;
- progressive change; and
- hydrogen superpower.

The slow-change scenario from the 2022 ISP scenarios has not been modelled given the low likelihood ascribed to this scenario in the draft 2022 ISP (i.e., the 4 per cent weighting AEMO gave this scenario).[11]

Table C-6 in Appendix C summarises the key variables in each scenario that influence the net benefits of the options.

[11] AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 57.

2.1.2. Early closures announced for coal power plants

There have been a number of announcements made since the PADR was released regarding the early closure of coal-fired power stations in the NEM. Specifically:

- AGL announced in February 2022 that the Loy Yang A power station in Victoria and Bayswater power station in NSW will close by at least 2045 and 2033, respectively (three years early);[12] and
- Origin Energy submitted a notice to AEMO in February 2022 for the potential early retirement of Eraring power station in August 2025 (seven years early).[13]

The wholesale market modelling undertaken as part of this PACR takes account of these updated dates (and draws directly on the latest AEMO generator information). However, since the market modelling undertaken for this RIT-T retires power stations according to when it is economic to do so (i.e., as opposed to at set dates), these announcements are considered to have only had a minor impact on the assessed wholesale market benefits in this RIT-T (since the above dates effectively set the latest point at which the plants can retire, if the market modelling has not found it economic to do so earlier in the assessment period).

2.1.3. A change in the statuses of the two non-network proposals assessed in the PADR

The statuses of the two options assessed in the PADR involving non-network components have changed. Specifically:

- the proponent of the BESS in Option 4 (Edify) has informed us that it now meets 'committed' status under the RIT-T[14] meaning that it features in both the base case and option case for the assessment with the result that there is no longer an incremental capital cost associated with this option; while
- the proponent of Option 5 (stand-alone BESS solution) has withdrawn their offer and a network-owned version of this standalone option has now been assessed in its place, for completeness, and based on our own database of costs for battery solutions rather than the earlier proponents' costs.

These updates have changed the manner in which these two options are assessed in the PACR, as outlined in section 4.5 and section 4.6, respectively.

2.1.4. Additional renewable generation connections (actual and planned) in the area

South-western NSW has seen significant growth in renewable connections to the transmission network as part of the wider energy market transition. Since the PADR, 200 MW of additional renewable generation has connected in the area, which reflects 794 MW of new renewable generation connecting in south-western NSW since December 2015 (with approximately a further 580 MW of renewable generation also currently being commissioned).

In addition, there are currently two publicly announced renewable generator connections in the Darlington Point – Wagga subsystem (up to 560 MW)[15] and one connection enquiry (200 MW) expecting to connect in

[12] AGL Energy, *ASX and Media Release – 1H22 Results Announcement*, 10 February 2022, available at: https://cdn-api.markitdigital.com/apiman-gateway/ASX/asx-research/1.0/file/2924-02485194-2A1355883?access_token=83ff96335c2d45a094df02a206a39ff4

[13] Origin Energy, Media release – Origin proposes to accelerate exit from coal-fired generation, 17 February 2022, available at: https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/

[14] While, at the date of this PACR, the Edify BESS is still listed as 'proposed' in the latest publicly available AEMO generation and storage database (dated February 2022), we note that there is a lag between when developments are considered 'committed' and them then appearing as such in the AEMO database. Edify have confirmed as part of this PACR that the BESS meets all relevant criteria under the RIT-T to be considered 'committed'.

[15] Namely, the Hay Sun Farm (http://www.overlandsunfarming.com.au/hay-sun-farm.html) and the Yarrabee Solar Power Project (http://www.yarrabeesolar.com/)

the Darlington Point area. None of these potential developments are considered 'committed' or 'anticipated' at this stage under the RIT-T but highlight the additional potential renewable generation uptake in the area.

2.1.5. A generator in the area has funded a temporary SPS

In December 2021, the constraint on Line 63 was relieved by around 200 MW (depending on system conditions) following Transgrid commissioning a temporary SPS, funded by a generator in the area.

Transgrid accepted and implemented the SPS as a temporary measure only (i.e., until a longer-term solution can be commissioned) as it is not considered to meet long-term network design standards. Specifically, the scheme involves tripping/disconnecting a number of renewable generators in the area (all of whom benefit from relieving the Line 63 constraint) and incorporates a delay to the controlled opening of Line 63 circuit breakers at Darlington Point and Wagga, requiring a longer than normal time if Line 63 needs to be taken out of service by AEMO in an emergency. These arrangements are not considered to be viable in the long-term.

Further, the SPS has been put in place by the generator as a temporary measure only, ahead of a long-term solution being put in place. A longer-term SPS is not considered a credible option in this PACR as it does not have a proponent.

In light of the SPS being funded by a generator only as a short-term measure until the optimal long-term solution can be identified and put in-place following this RIT-T, we have not included the SPS in the core market modelling undertaken for this PACR. However, we have included a sensitivity reflecting the SPS being in place until a new line can be commissioned, which shows it does not affect the conclusion of this PACR (as outlined in section 7.5.1).

2.2. 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 Transmission Network Service Providers (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.

Power flows east towards Wagga Wagga have not been high enough until recently to cause stability issues during an outage of Line 63. Operational measures have therefore not been put in place to manage high easterly flows.

More than 790 MW of renewable generation has connected in the area since December 2015 and approximately 580 MW of renewable generation is currently being commissioned.[16] The commissioning of

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

new generation west of Darlington Point resulted in high power flows east towards Wagga Wagga from mid-2020.

If action is not taken, the 132 kV system will 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, AEMO implemented a new system normal constraint in the NEMDE on 8 May 2020 to limit power flows on Line 63, which was updated on 1 December 2021 following the commissioning of a proponent-funded temporary SPS (discussed in section 2.1.5 above). This constraint has been developed to minimise the risk of voltage collapse at Darlington Point and the constraint equation includes generators in south-western NSW and north-west Victoria as well as Murraylink.[17] 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.

Prior to the 1 December 2021 update, the constraint bound for 12,263 dispatch intervals (1,021 hours) over the course of 2021 and, after the 1 December 2021 update, the updated constraint bound for 821 dispatch intervals (68 hours) in the two months to 1 February 2022.

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. Power flows east from existing generation in south-western NSW presently peak at more than 790 MW and a further 580 MW of generation is due to be commissioned in south-western NSW in 2021-22. This has resulted in material constraints to some generators in the region.

Many of the submitters to the PADR highlighted the impact of the constraint on both themselves and the NEM more broadly. All of the existing or new renewable generators in south-western NSW that submitted to the PADR commented on the impact of the constraint.

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 expected from the options assessed.

We note that while AEMO implemented a further system normal constraint regarding voltage collapse in south-western NSW on 20 November 2020,[18] this constraint is not considered material for this RIT-T. Specifically, the voltage limit announced in November 2020 imposes a flow limitation from Balranald to Darlington Point of 150 MW and is expected to be alleviated following commissioning of EnergyConnect. While its imposition may provide additional market benefits for Option 4 and Option 5 in this RIT-T, since

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

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

the battery energy storage system (BESS) components of these options 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 will not change the conclusion regarding Option 4 being the preferred option overall (as set out in sections 7 and 8).

2.3. Avoided and deferred 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 costs of new capacity in the NEM is a key modelled benefit of the options considered in this PACR.

Each of the credible options assessed as part of this PACR 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 make up the overwhelming majority of the market benefits estimated for the step-change and hydrogen superpower scenarios and are expected from the early years of the modelling (with significant benefits accruing from the early to mid-2020s).

The progressive change scenario is expected to have a smaller amount of investment affected in the early years compared to the other scenarios. A number of factors drive this result, such as lower demand in this scenario as well as no carbon budget constraint before 2029/30 (which is a driver in a lower level of coal retirement in this scenario and thus a lower need for new investment, particularly renewable investment). However, avoided or deferred costs of new generation and storage still make up the majority of the estimated market benefits under this scenario.

Section 7 summarises the specific types of investment that are deferred or avoided under each of the scenarios modelled, compared to the base case.

2.4. Avoided generator dispatch costs

The wholesale market modelling undertaken in this PACR finds that the avoided dispatch costs of higher cost generators is a significant market benefit category for the preferred option under the progressive change scenario. This is due to the lower level of coal retirement in this scenario (as outlined above) and the fact that the options enable this coal generation to be displaced by renewable generation in south-western NSW.

Section 7 summarises the specific types (and broad locations) of generation dispatch that is avoided under the progressive change scenario, compared to the base case where the constraint remains in-place going forward.

Under the step-change or hydrogen superpower scenarios the preferred option is found to result in a small net cost in terms of generator dispatch costs overall, albeit that this is substantially offset by the avoided/deferred investment cost savings.

3. Consultation on the PADR

The PADR was released in September 2021 and we subsequently received submissions from six parties.

The submitters can be grouped as follows:

- existing or new renewable generators in south-western NSW – Darlington Point Solar Farm, RWE Renewables Australia, Reach Solar Energy Co, Iberdrola Australia and one party who wished to remain confidential; and
- the Public Interest Advocacy Centre (PIAC).

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

- support for the identified need;
- current cost recovery arrangements;
- feasibility of BESS options;
- support for interim solutions;
- comments on the scenario analysis;
- future proofing the options; and
- the RIT-T timeframes and construction timetable.

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

3.1. Support for the identified need

All of the existing or new renewable generators in south-western NSW supported the identified need outlined in the PACR. They stated that the constraints are curtailing low-cost renewable generation, representing a lost opportunity for consumers to benefit through lower electricity prices in NSW.[19]

Reach Solar Energy Co, via a supporting letter from the Narrandera Shire Council, noted the broader economic benefits of new transmission infrastructure, including local employment in the region and offering farmers the opportunity to diversify their income.[20] While we agree that these are expected real sources of benefit, they are not able to be captured in the RIT-T analysis due to it being a cost-benefit assessment focussed on 'all those who produce, consume and transport electricity in the market'[21] and these types of benefits are considered 'externalities' under the RIT-T.[22]

[19] Darlington Point Solar Farm Submission, p. 1, RWE Renewables Australia Submission, p. 1 & Iberdrola Australia Limited, p. 1
[20] Narrandera Shire Council, p. 1 (letter submitted to/with the Reach Solar Energy Co submission).
[21] NER clause 5.15A.1(c).
[22] AER, *Application Guidelines Regulatory Investment Test for Transmission*, August 2020, p, 55.

3.2. Commentary on the current cost recovery arrangements

PIAC did not support the proposed investment under the current cost recovery arrangements, which they stated would require consumers to pay for the proposed network upgrades. PIAC suggested that generation businesses, not consumers, are the primary beneficiaries of the upgrades proposed.[23]

PIAC suggested Transgrid should seek funding from generation businesses if it considers the upgrades have merit. PIAC suggested that the revenue benefit for generators will be greater than the wholesale market benefits for consumers and, if generators are unwilling to fund the upgrades, this casts doubt on Transgrid's estimates of costs and benefits.[24]

We note that the current cost recovery arrangements are reflected in the NER and it is not the role of the RIT-T to consider alternative cost recovery arrangements, nor to preclude investments that are shown to have a positive net market benefit from proceeding based on the current cost recovery arrangements. We note also PIAC's wider advocacy for a change in the cost recovery arrangements in the NER which we understand may form the basis for a future Rule change proposal that would then be considered further by the Australian Energy Market Commission as part of the formal Rule change process.

Moreover, we expect the net benefits of the preferred option to flow to end-consumers over time as investment costs in the NEM are lowered in the long-run, compared to what would have happened if action was not taken. Both Option 4 and Option 1A are expected to generate sufficient benefits to recover their costs within five years of commissioning the new line in the step-change and hydrogen superpower scenarios, and ten years in the progressive change scenario.

3.3. Feasibility of BESS options

Reach Solar Energy Co commented that cost estimates were not provided in the PADR for Option 4 and Option 5 (which are options that involve BESS) and that, based on a review by their technical advisors, these options are not likely to provide complete solutions to the identified need. They submitted that the assessment should consider the transmission line solutions versus non-network solutions on a 'like-for like' basis and that:[25]

- energy storage systems should be evaluated at the energy storage (MWh) required to restore Line 63 from an expected outage – they submitted that recent actual transmission line outages in Victoria and South Australia suggest a minimum of two to three weeks to install temporary towers, equating to a BESS storage of 302,400 MWh to 453,600 MWh, rendering these solutions prohibitive and not comparable to a transmission line solution;
- the shorter asset life for energy storage systems should be reflected in the assessment; and
- that transmission lines have very high reliability and that energy storage systems consist of various sensitive components that will fail over the course of their lives.

We note that the costs of these two options were redacted from the PADR to preserve the confidentiality requested by their third-party proponents.

Further, as outlined in sections 2.1 and 4.5, the proponent of the interim BESS in Option 4 (Edify) has informed us that it now meets 'committed' status under the RIT-T and is currently going through the connection application process (and so now has a zero incremental capital cost for the purpose of the

[23] Public Interest Advocacy Centre Submission, p. 1
[24] Public Interest Advocacy Centre Submission, p. 1
[25] Reach Solar Energy Co Pty Ltd, p. 2

PACR assessment). We have continued to assume the technically feasibility of this option to provide interim network support for the purposes of the PACR). However, we note that the ability of the BESS component to relieve the constraint still requires full technical feasibility to be confirmed and agreed with AEMO (which will occur following this PACR).

While we have not exhaustively tested and confirmed the technical feasibility of the BESS in Option 5 (and, instead, assumed it for the purposes of the PACR), we note that this option does not rank well in the cost benefit assessment and is not considered the preferred option (as outlined in section 7).

In addition, we note that the PACR assessment reflects the shorter asset lives of BESS through replacement BESS being required over the assessment period.

3.4. The use of interim solutions

Darlington Point Solar Farm and RWE Renewables expressed continued interest 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.[26]

We note that Option 4 involves the use of a BESS solution deployed to assist before a longer-term option can be commissioned. This option has been identified as the preferred option under this RIT-T and, as noted above, we will be working closely with AEMO and the proponent (Edify) to progress this option as an interim solution ahead of the commissioning of the new transmission line.

We do not consider that there are other interim solutions that can assist and nor have any proponents reached out with proposals.

3.5. Comments on the scenario analysis

Iberdrola submitted that the NEM is currently projected to move faster than AEMO's 2020 step-change scenario and so only one of the four core scenarios in the PADR is likely to be relevant.[27] Darlington Point Solar Farm submitted that the step-change scenario is the most appropriate scenario for assessing the costs and benefits of the proposed options.[28]

The scenarios adopted in the PACR analysis (and the relative weighting of the outcome across the scenarios) have been updated to reflect the draft 2022 ISP released by AEMO in December 2021 (see section 5.1). The adoption of the scenarios used by AEMO for the ISP is in line with the AER's RIT-T Guidelines.[29]

Iberdrola suggested that Transgrid should analyse its scenarios with a much higher uptake of renewable energy across NSW, consistent with Australia's' commitments to net-zero by 2050.[30] We note that all of the scenarios modelled in this PACR assume net-zero by 2050, although each takes a different path, and are consistent with the 2022 ISP scenarios.[31]

[26] Darlington Point Solar Farm Submission, p.2, RWE Renewables Australia submission, p. 2
[27] Iberdrola Australia Limited, pp. 1-2
[28] Darlington Point Solar Farm, p. 1
[29] AER, *Application Guidelines Regulatory Investment Test for Transmission*, August 2020, p, 25.
[30] Iberdrola Australia Limited, p. 3
[31] AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 28.

Iberdrola also submitted that:[32]

- Avonlie solar farm is now committed at 190 MW-ac (245 MWdc), rather than 160 MW-ac, including approval for a 100 MW DC coupled BESS (but that this component is not yet committed); and
- Yanco solar farm south of Griffith is also now committed and may impact on the scenario analysis.

The market modelling in the PACR assumes both the Avonlie and Yanco solar farms are committed in the assessment. The Avonlie 100 MW BESS has not been included in the base case as it is not considered committed (as noted by Iberdrola) and nor is it expected to affect the net benefits of the options assessed (assuming it does go ahead) since it would sit behind the solar farm inverters.

3.6. Future proofing the options

Iberdrola suggested that, given Australia's renewed commitment to net-zero by 2050, it might also warrant consideration of whether additional reinforcements or investment being made at the same time would be of value to consumers.[33] They proposed that Transgrid considers, amongst other options, an upgrade of one of the lines between Avonlie and Wagga Wagga. With increased uptake of renewables in the area, the 132 kV lines from Avonlie to Wagga Wagga may be impacted by binding constraints in the event of contingencies on the nearby 330 kV lines or one of the two existing 132 kV lines.[34] They also suggested that we engage with the NSW Government and the Consumer Trustee to consider the options.[35]

We understand that these issues are likely to be covered in the separate process being run by the NSW government, i.e., that run by the Consumer Trustee and the Infrastructure Planner as part of the development of the SW REZ. Alternatively, additional investment may be subject to a separate RIT-T in the future, if a constraint materialises, since it would be addressing a fundamentally different identified need.

3.7. Timetable of the project

A number of parties commented on the RIT-T timing, requesting that we fast-track the RIT-T.[36]

We recognise that the current constraint is impacting existing and planned generators in the area, and that stakeholders have expressed their support for this RIT-T process to be progressed swiftly. However, it is important to ensure that the outcome is robust and reflects the latest externally consulted on assumptions regarding the development of the NEM. We have therefore aligned the assessment in this PACR with the assumptions adopted in AEMO's draft ISP released in December 2021.

32 Iberdrola Australia Limited, p. 1
33 Iberdrola Australia Submission, p. 2
34 Iberdrola Australia Submission, p. 3
35 Iberdrola Australia Submission, p. 3
36 Darlington Point Solar Farm Submission, p. 2, Reach Solar Energy Submission, p. 2, RWE Renewables Submission, p. 2.

4. Credible options assessed

We have 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 BESS solution; and
- Option 5 – a standalone long-term BESS solution.

Option 4 involves the use of an interim BESS that was proposed by a third-party (Edify) in response to the PSCR. Edify would be the owner of the BESS under this option and would receive a network support payment from Transgrid. Since the PADR was released, the BESS component (which is being independently developed) has now been confirmed as 'committed' under the RIT-T (as discussed further in section 4.5).

The PADR also included a third-party owned stand-alone BESS solution (Option 5). We note that the proponent for this solution has since withdrawn their offer. However, the PACR continues to assess a stand-alone BESS solution for completeness of the analysis but now assumes that it would be Transgrid-owned. The cost, build time and operating characteristics of this option are based on our internal database for such solutions and do not draw on what was proposed by the original proponent of this option.

Table 4-2 below summarises each of the credible options assessed in this PACR.

Table 4-2: Summary of the credible options

Option	Description	Estimated capital cost	Expected commissioning year
1A	Establish a new Darlington Point to Dinawan 330 kV transmission line	$166.9 million	2025/26
1B	Rebuild the existing 99T Darlington Point to Coleambally and 99L Coleambally to Deniliquin as 330 kV to Dinawan	$222.2 million	2025/26
2	Establish a new Wagga Wagga to Darlington Point 330 kV transmission line	$285.4 million	2026/27
3	STATCOM (100 MVar)	$33.2 million	2025/26

Option	Description	Estimated capital cost	Expected commissioning year
4	Option 1A[37] + 3-year interim network support solution utilising a BESS (proposed by Edify)	$166.9 million (for network component) The network support component has no incremental capital costs compared to the base case (since the battery is considered 'committed', as outlined in section 2.1.3). The proposed annual network support cost (opex) is $3.25 million/year for the three years of support.	2025/26 for the network component 2023/24 for the network support from the BESS
5	A standalone long-term BESS solution (network owned)[38]	$216.0 million (initial) $102.1m (reinvestment)	2024/25 (initial) 2044/45 (reinvestment)

Table 4-3 provides a further breakdown of the categories of capital cost estimated for each of the credible options.

Table 4-3: Breakdown of the estimated capital costs of the credible options

Option	Lines	Substations	Land	Batteries	Total
1A	$125.7m	$15.3m	$25.9m	-	$166.9m
1B	$180.4m	$15.9m	$25.9m	-	$222.2m
2	$209.0m	$17.3m	$59.1m	-	$285.4m
3	-	$33.2m	-	-	$33.2m
4	$125.7m	$15.3m	$25.9m	-	$166.9m
5	-	-	-	$216.0m (initial) $102.1m (reinvestment)	$318.1m

We do not foresee material biodiversity offset costs for any of the options assessed (as has been included in other RIT-Ts) as they would not require any material clearing works.

The assumed timing for each option has been reviewed and updated since the PADR to reflect both the passage of time as well as the latest views regarding when each option can realistically be delivered (from both the internal Transgrid project delivery team as well as the third party proponent of the BESS in Option 4).

Capital costs have been revised since the PADR in order to take account of current market trends and risks, drawing on the experience of recent projects as well as a detailed review of the scope of each option. The revised costs in this PACR are consequently lower than in the PADR as a result of this process.

[37] As was the case in the PADR, the interim 3-year BESS 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. Coupling Option 1B or Option 2 with an interim 3-year BESS solution would not therefore rank higher in the RIT-T assessment than Option 1A with the interim 3-year BESS solution.

[38] In this PADR, this option represented a proposal by a third party. The proponent has since withdrawn their proposal and so this option now represents a network-owned solution (and the costs have changed as a result).

The assumed costs are very important to the outcome of this RIT-T and we have therefore investigated a number of 'boundary tests' on the costs that give us additional confidence that the identification of the preferred option is robust to the assumed underlying costs (as outlined in section 7.5.2).

All network options are assumed to have annual operating and maintenance costs equal to approximately one per cent of their capital costs. Option 4 also involves a network support payment to Edify for the BESS component but this is netted off in the net benefit calculations (as outlined in section 6.1).

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).

We have 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

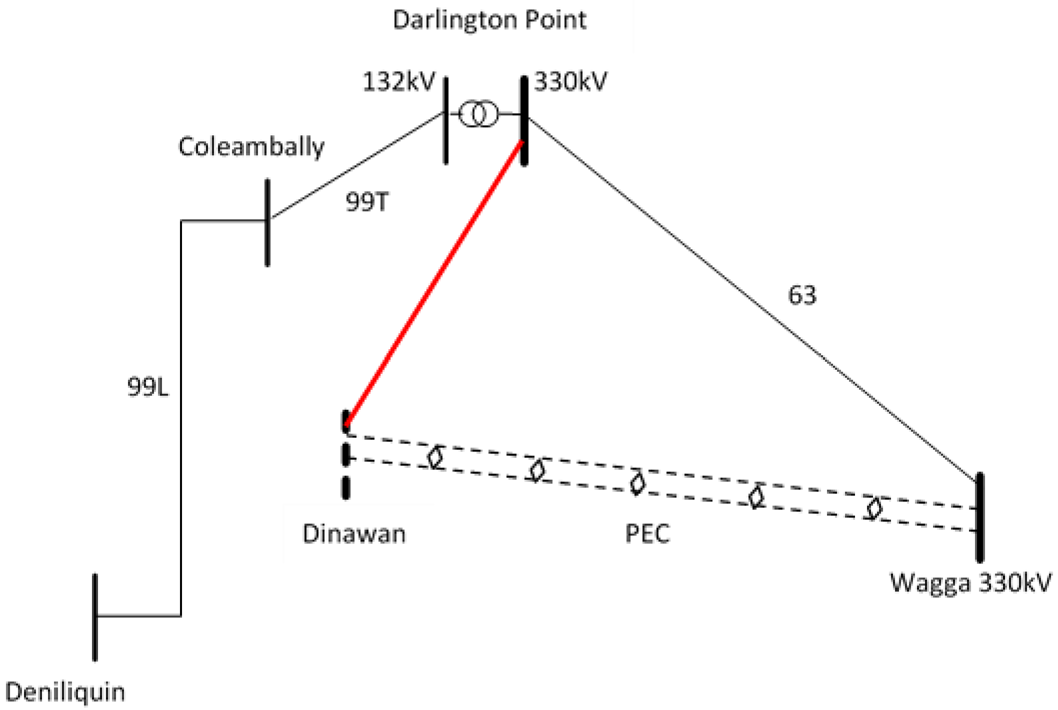
Option 1A involves the establishment of a new greenfield transmission line between Darlington Point and the new Dinawan substation (that will be developed as part of EnergyConnect).

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.

Figure 4-1: Option 1A network diagram



The estimated capital cost of Option 1A is $166.9 million. Delivery is expected to take 4-5 years, with commissioning possible in 2025/26, subject to obtaining necessary environmental and development approvals.

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

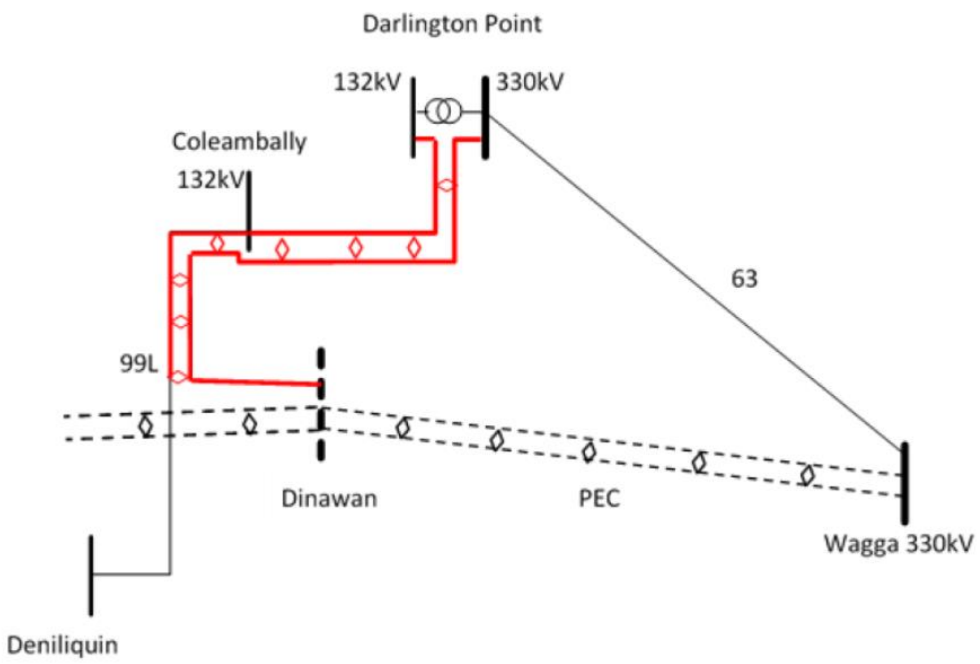
Option 1B involves the rebuild of existing 132 kV transmission lines to establish a 330 kV connection between Darlington Point and the proposed Dinawan substation. This option is consistent with Transgrid's overall general preference for brownfield investments.

The high-level scope of this option includes:

- rebuild the existing 99T Darlington Point to Coleambally 132 kV circuit as a 330 kV double circuit transmission line (approximately 13 km), with one side to be operated at 132 kV;
- 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 41 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 31 km); 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 $222.2 million. Option 1B is more expensive than Option 1A due to the cost of rebuilding the existing 132 kV transmission line and rebuilding as a 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 2025/26, subject to obtaining necessary environmental and development approvals.

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

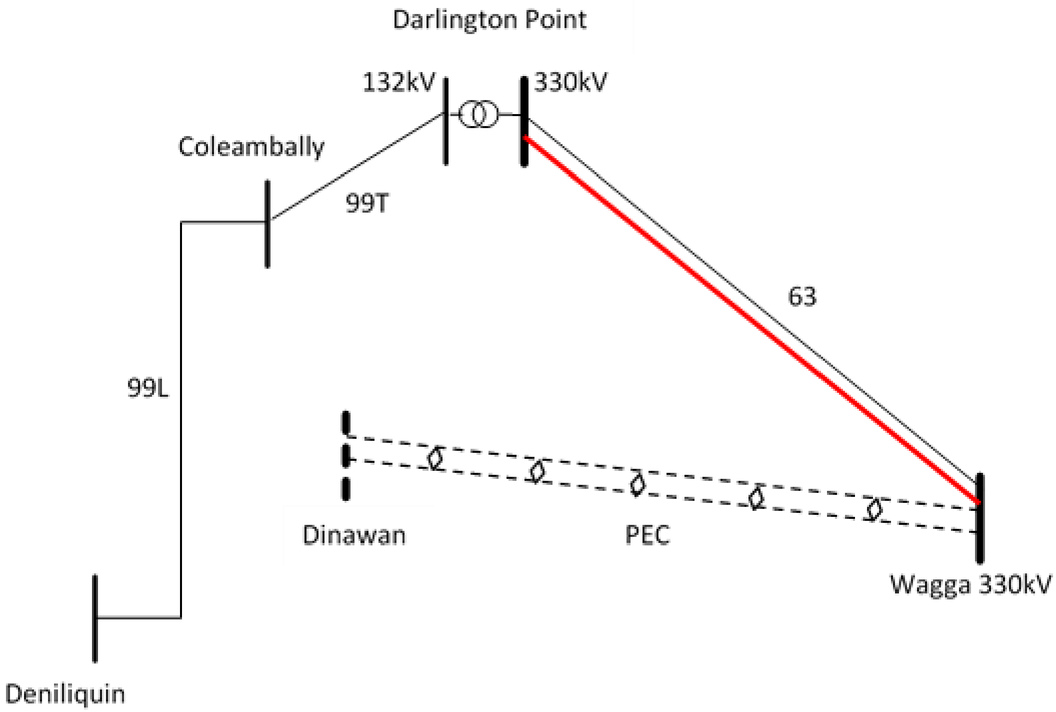
Option 2 involves the establishment of a new 330 kV single circuit transmission line between Wagga Wagga 330/132 kV substation and Darlington Point substation.

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 $285.4 million. Delivery is expected to take 4-5 years, with commissioning possible in 2026/27,[39] subject to obtaining necessary environmental and development approvals.

[39] While Option 2 has the same broad delivery time estimate as the other options (i.e., 4-5 years), we expect that it will actually be towards the end of this range (which is why this option is assumed to be commissioned a year later than the other options).

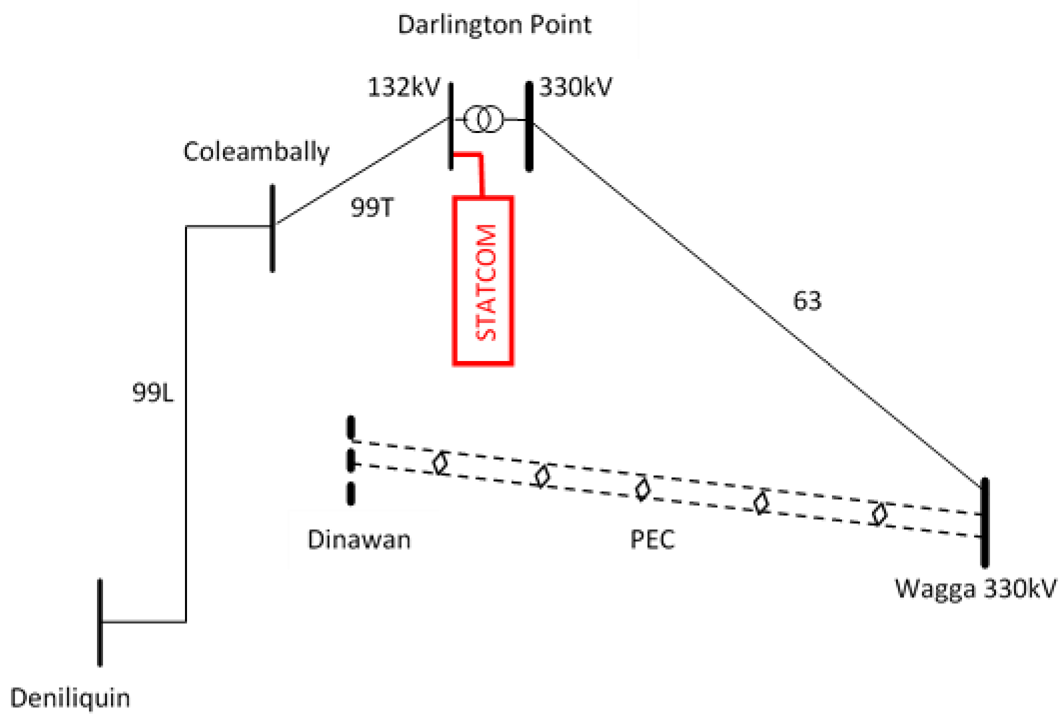
4.4. Option 3 – STATCOM

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

We noted in the PADR 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, we continue to include the STATCOM solution on an indicative basis in the PACR analysis to identify whether, if it was technically feasible and could alleviate the constraint, 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 $33.2 million. Delivery is expected to take 3-4 years, with commissioning possible in 2025/26,[40] subject to obtaining necessary environmental and development approvals.

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

Option 4 involves the exact same network components as Option 1A outlined above as well as the use of a BESS solution for three years to provide network support before the new network can be commissioned, as proposed by Edify in response to the PSCR.[41]

[40] While STATCOMs are considered quicker to install than the line work in the other options, they are also highly bespoke components that require significant upfront design work, procurement and manufacturing compared to the other options. The consequence of this is that Option 3 has the same delivery/build time as Option 1A.

[41] As was the case in the PADR, the interim 3-year BESS 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 BESS solution would not therefore rank higher in the RIT-T assessment than Option 1A with the interim 3-year BESS solution.

The estimated capital costs of the network elements are $166.9 million. The BESS component which provides the interim network support has no incremental capital costs compared to the base case (since it is considered 'committed', as outlined in section 2.1.3).

Option 4 involves a network support payment to Edify for the BESS component but this is netted off in the net benefit calculations (as outlined in section 6.1).

The network support capability would be available from July 2023. Delivery of the network element is expected to take the same time as Option 1A and be commissioned in 2025/26.[42]

Edify would be the owner of the BESS under this option and, as outlined in section 2.1, the BESS development is going ahead independent of this RIT-T and it has now been confirmed as 'committed' under the RIT-T.[43] This is a key change from the PADR for this option as the costs of the BESS component now feature in both the base case and the Option 4 case and so effectively have no bearing in the RIT-T assessment.[44]

The proponent has advised us that the full capacity of the BESS will be available for trading in the wholesale market while also providing the interim network support services. The consequence of this is that the BESS component does not provide direct wholesale market benefits since its operation, from the perspective of the wholesale market, does not change between the base case and the Option 4 case. It does however provide indirect wholesale market benefits, as the other options do, through relieving the constraint on Line 63.

While the BESS is able to provide network support for a period of three years, it is not considered to constitute a longer-term solution and replace the need for the network component (Option 1A). Specifically, while the BESS can relieve the constraint for current existing and committed generators in the region, our preliminary assessments indicate that it is impractical to reconfigure the BESS controls to continue to provide the identified benefits when more new generators connect to the network due to BESS system technical limitations such as the limit to system strength contribution (i.e., fault current limitations) and the need to satisfy its performance standard for normal market operation.[45]

Consequently, the BESS component has been included as an interim measure for the three years only (as proposed by the proponent).

4.6. Option 5 – Standalone long-term BESS solution

Option 5 involves a standalone BESS 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 estimated capital cost of Option 5 is $216.0 million for the initial BESS. Delivery is expected to take 1-2 years, with commissioning possible in 2024/25, subject to obtaining necessary environmental and

42 While there are two years between when the network support capability would be available from the BESS and when the network element can be commissioned, we have included three years of network support in the NPV modelling (i.e., network support is provided the year the network element is commissioned) to cater for delivery uncertainty. We note that this has no bearing on the assessment as network costs are netted off in the NPV assessment.

43 While, at the date of this PACR, the Edify BESS is still listed as 'proposed' in the latest publicly available AEMO generation and storage database (dated February 2022), we note that there is a lag between when developments are considered 'committed' and them then appearing as such in the AEMO database. Edify have confirmed as part of this PACR that the BESS meets all relevant criteria under the RIT-T to be considered 'committed'.

44 We have confirmed that the costs of the BESS would not change if coupled with Option 1A (ie, as part of Option 4) compared to the base case, e.g., due to a different sized BESS being required.

45 We currently consider these processes will take around 30 weeks to complete and cost the new connecting generator approximately $600,000 (please note also that both of these estimates are considered conservative).

development approvals.[46] The BESS is expected to have an asset life of 20 years, after which a replacement BESS is assumed to be required in 2044/45, with an estimated capital cost of $102.1 million.

While this option in the PADR involved a third-party owned stand-alone BESS solution, the proponent has since withdrawn their offer. This option in the PACR is now a network-owned version and the cost, build time and operating characteristics of this option are based on our internal database for such solutions and do not draw on what was proposed by the original proponent of this option.

We have not exhaustively tested and confirmed the technical feasibility of the BESS in Option 5 given this is a substantial exercise and, instead, we have assumed it for the purposes of the PACR. However, we note that this option does not rank favourably in the cost benefit assessment and is not considered the preferred option overall (as outlined in section 7).

Moreover, we consider that Option 5 would have similar practical issues as the BESS component in Option 4 (i.e., needing to reconfigure the battery as new generators connect in the future), although to a likely lesser extent.

4.7. Options considered but not progressed

We have 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 4-4. These options were not commented on in submissions to the PSCR.

Table 4-4: Options considered but not progressed

Option	Reason(s) for not progressing
Third-party owned standalone long-term BESS solution	As outlined in section 4.6 above, the third-party proponent of this option at the PADR stage has since withdrawn their offer.
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.

[46] We note that the delivery and commissioning date for this option is considered optimistic and is to be interpreted only as indicative. Extending the delivery time/commissioning date is not expected to be material for this option however based on how poorly it fares in the NPV assessment.

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. We have identified the 'boundary value' for key factors, beyond which the outcome of the analysis would change.

5.1. The assessment considers three '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 three scenarios as part of this PACR assessment, which differ in terms of the key drivers of the estimated net market benefits. The scenarios considered have been updated since the PADR.[47] Specifically, we have modelled the market benefits of each of the options across each of the following three 2022 ISP scenarios:

- step-change;
- progressive change; and
- hydrogen superpower.

The slow-change scenario from the 2022 ISP scenarios has not been modelled given the low likelihood ascribed to this scenario in the draft 2022 ISP (i.e., the 4 per cent weighting AEMO gave this scenario).[48]

Table C-6 in Appendix C summarises the key variables in each scenario that influence the net benefits of the options.

We have weighted each of the scenarios based on the draft 2022 ISP weightings. Specifically, we have given each scenario a weighting based on the proportion its weighting in the draft 2022 ISP makes up of the cumulative 96 per cent given to these three scenarios, i.e.:[49]

- 52 per cent to the step-change;

[47] See discussion in section 2.1.1.
[48] AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 57.
[49] We note also that these weights align with the weights AEMO have recommended be applied to the VNI West RIT-T (where the same three scenarios are to be considered) in the draft 2022 ISP released in December 2021 – see: AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 69.

- 30 per cent to the progressive change; and
- 18 per cent to the hydrogen superpower.

While these weights have been applied to weight the estimated market benefits and identify the preferred option across scenarios (illustrated in section 7), we have also carefully considered the results in each scenario in section 7.

5.2. Sensitivity analysis

As outlined above, the three 2022 ISP scenarios cover a range of assumptions that are expected to affect the net benefits of the options assessed in this PACR.

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

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

- the impact of the temporary SPS funded by a generator;
- changes in the capital costs of the credible options; and
- alternate commercial discount rate assumptions.

The results of the sensitivity tests are discussed in section 7.5.

In addition, we have also sought to identify the 'boundary value' for key variables beyond which the outcome of the analysis would change.

6. Estimating the market benefits

As outlined in section 2, depending on the scenario, the key benefits expected from the options stem from more efficient building of new capacity and avoided generator dispatch costs.

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. It first covers how the costs of the non-network component (as part of Option 4) have been captured in the analysis.

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

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

6.1. Treatment of BESS component costs

The costs of the BESS component (i.e., the interim battery network support component for Option 4) have been incorporated in the PACR assessment in line with the revised guidance provided by the AER as part of its 2020 update of the RIT-T Application Guidelines.[50]

In particular, the PACR assessment reflects:

- the proposed network support cost as the cost of the option (this is an operating cost that will be payable by Transgrid and is approved by the AER under the network support pass through provisions in the NER); and
- the same network support cost as a benefit to the option proponent.

These costs therefore net off in the NPV assessment.

A key change since the PADR assessment is that the capital costs of the BESS component now feature in both the base case and the Option 4 case and so effectively have no bearing in the RIT-T assessment.[51] This is on account of the proponent informing us that the BESS meets the status of 'committed' under the RIT-T (as outlined in section 4.5 above).[52]

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

[51] We have confirmed that the costs of the BESS would not change if coupled with Option 1A (ie, as part of Option 4) compared to the base case, e.g., due to a different sized BESS being required.

[52] While, at the date of this PACR, the Edify BESS is still listed as 'proposed' in the latest publicly available AEMO generation and storage database (dated February 2022), we note that there is a lag between when developments are considered 'committed' and them then appearing as such in the AEMO database. Edify have confirmed as part of this PACR that the BESS meets all relevant criteria under the RIT-T to be considered 'committed'.

6.2. Expected market benefits from expanding transfer capacity

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

- changes in costs for parties, other than the RIT-T proponent (i.e., changes in investment in generation and storage);
- changes in fuel consumption in the NEM arising through different patterns of generation dispatch;
- 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.

6.2.1. 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 most material category of market benefit estimated across the three scenarios.

6.2.2. 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.

One of the 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. As shown in section 7, this is only a material category of market benefit under the progressive change scenario.

6.2.3. 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).

This category of market benefit has been found to be relatively small within the market modelling.

6.2.4. 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 Expected Unserved Energy (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.

6.2.5. 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 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 small within the market modelling, reflecting that the level of voluntary load curtailment is not significantly different between the option cases and the base case.

6.2.6. 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 PACR.

6.3. General modelling parameters adopted

The RIT-T analysis spans a 27-year assessment period from 2021-22 to 2047-48. This reflects the capital cost profile of the options as well as 25 years of wholesale market modelling by EY (from 2023-24 to 2047-48).

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.[53] 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. We note 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 well before the end of the assessment period under all three scenarios.

A real, pre-tax discount rate of 5.50 per cent has been adopted as the central assumption for the NPV analysis presented in this PADR, consistent with the assumptions adopted in 2021 Inputs, Assumptions and Scenarios (IASR). The RIT-T also requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 1.96 per cent,[54] and an upper bound discount rate of 7.50 per cent (i.e., the upper bound proposed for the 2022 ISP[55]).

6.4. Classes of market benefit not considered material

The NER requires that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific category (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option.[56]

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 PACR do not exhibit flexibility in terms of how they can be developed. We do 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. We consider 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 PACR. 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 (and the option with the largest wholesale market benefits (Option 4) already being found to be the top-ranking option in all three scenarios assessed).

[53] We note also that where assets have asset lives shorter than the assessment period (i.e., the Option 5 BESS), we assume reinvestment in order to ensure all options are assessed on a 'like-for-like' basis.
[54] 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/ausnet-services-determination-2022%E2%80%9327/final-decision
[55] AEMO, *2021 Inputs, Assumptions and Scenarios Report*, July 2021, p. 105.
[56] NER clause 5.16.1(c)(6).

7. Net present value results

This section outlines the results of the NPV assessment we have undertaken of the credible options.

The accompanying EY market modelling report provides additional detail in terms of the modelled wholesale market impacts for each option, under each scenario.

7.1. Step-change scenario

The step-change scenario is summarised by AEMO as 'rapid consumer-led transformation of the energy sector and coordinated economy-wide action'. The step-change scenario moves quickly initially to fulfilling Australia's net zero policy commitments and, rather than building momentum (as is the case for the progressive change scenario), sees a consistently fast-paced transition from fossil fuel to renewable energy in the NEM. By 2050, this scenario assumes that most consumers rely on electricity for heating and transport, and the global manufacture of internal-combustion vehicles has all but ceased.[57]

Under these assumptions, Option 4 is found to be the top-ranked option with estimated net market benefits of $129 million. Option 1A, which is the network component of Option 4 (i.e., just the New Darlington Point to Dinawan 330 kV transmission line), is the second-ranked option with estimated net market benefits of $94 million. All other options fall substantially behind Option 4 and Option 1A (with Option 5 resulting in a small net cost).

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

Figure 7-1: Summary of the estimated net benefits under the step-change scenario[58]

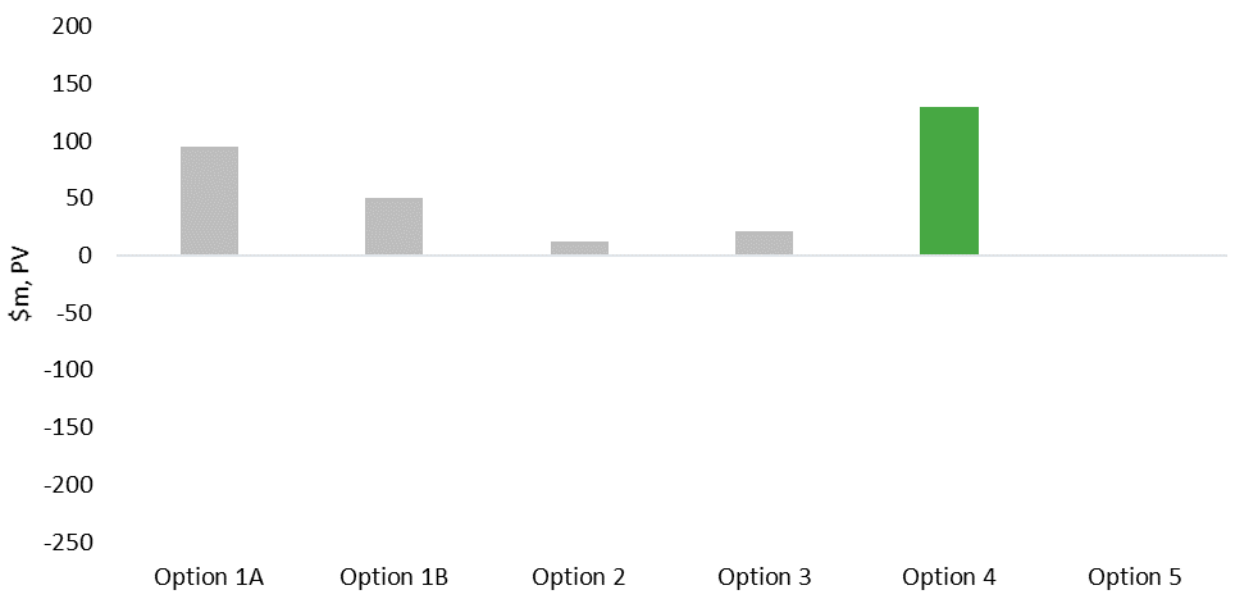
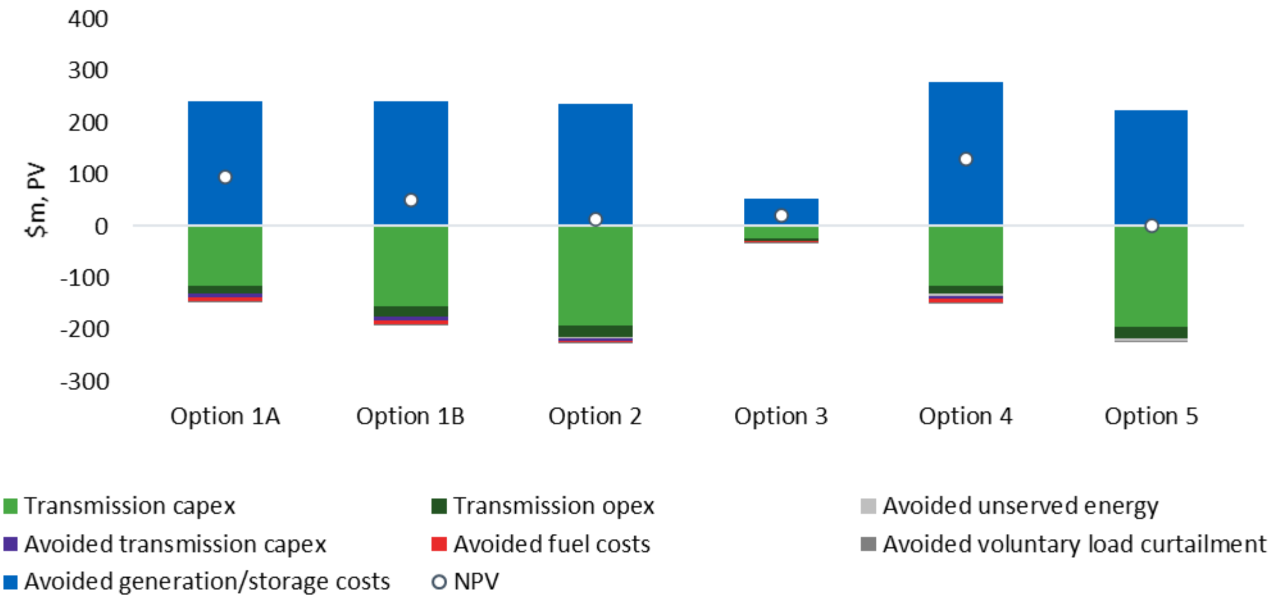


Figure 7-2 shows the composition of estimated net benefits for each option under the step-change scenario.

[57] AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 27.
[58] Option 5 exhibits a slightly negative net benefit of $67,000, and therefore is close to zero net benefit in this figure given the scale used.

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



The vast majority of the estimated market benefits for the options under this scenario come from avoided and deferred costs for new generators and storage. This is driven primarily by avoided fixed operating and maintenance costs from the early retirement of black coal plants and avoided or deferred solar capital costs.

Figure 7-3 below presents the estimated cumulative expected gross benefits for Option 4 for each year of the assessment period under the step-change scenario.[59] It shows that the majority of the overall benefits have accrued by the mid- to late-2020s under this scenario.

[59] This figure only presents the annual breakdown of estimated gross benefits for the preferred investment option Option 4. 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 4 shown in Figure 7-2 above. This applies to all figures of this type in this document.

Figure 7-3: Breakdown of cumulative gross benefits for Option 4 under the step-change scenario[60]

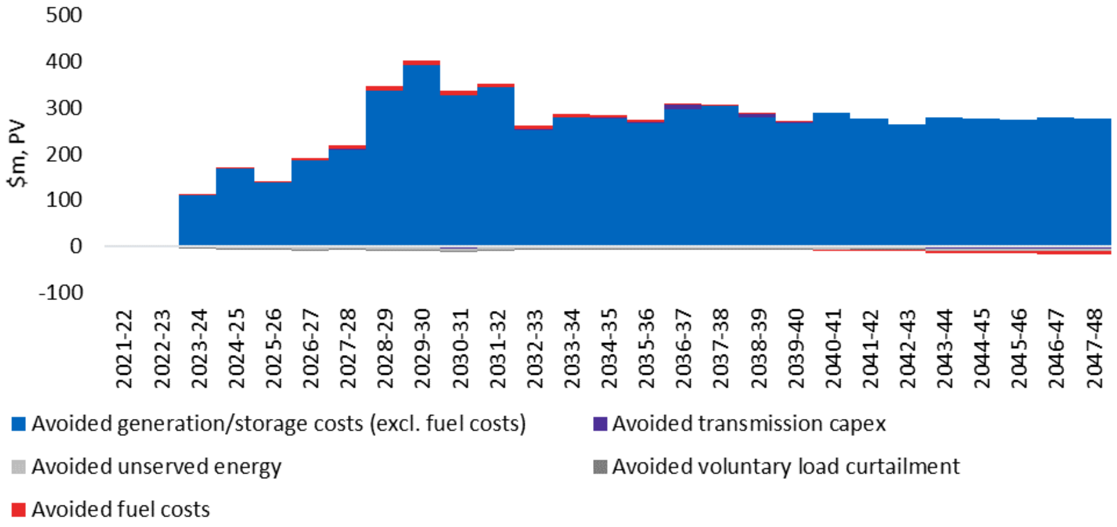
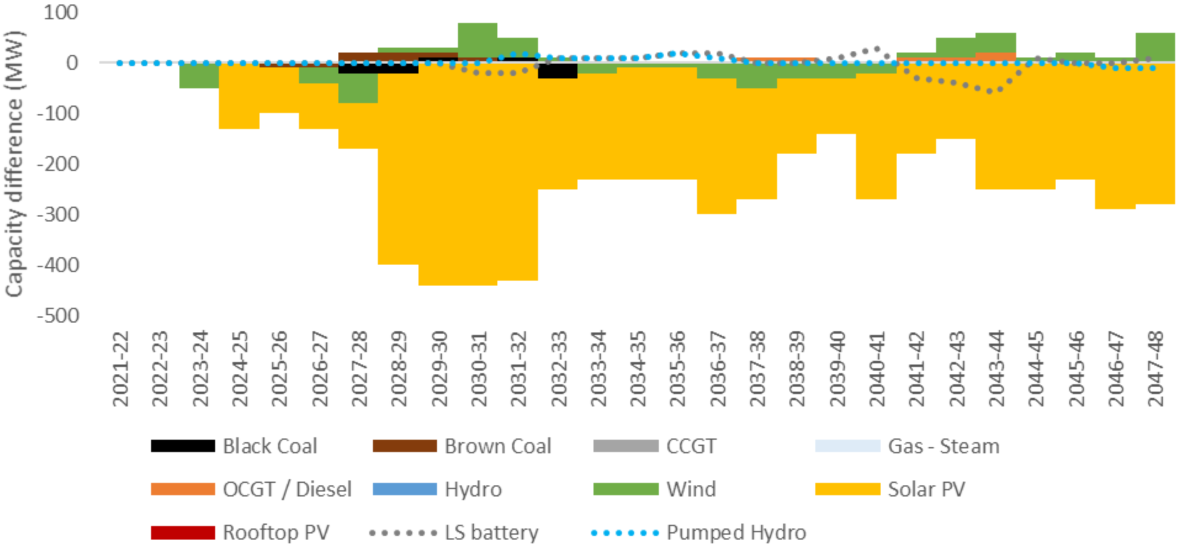


Figure 7-4 summarises the difference in generation and storage capacity modelled for Option 4 (in MW), compared to the base case, i.e., what is found to be driving the avoided or deferred costs associated with generation and storage benefit. The accompanying market modelling results workbook provides the data underpinning this chart, as well as the same data for all other options, benefit classes and scenarios (at both the technology and regional levels).

60 While all generator and storage capital costs have been included in the market modelling on an annualised basis, this chart, and all charts of this nature in the PACR, present the entire capital costs of these plant in the year avoided in order to highlight the timing of the expected market benefits. This is purely a presentational choice that we have made to assist with relaying the timing of expected benefits and does not affect the overall estimated net benefit of the options. A decrease in the blue bars between years therefore signifies where Option 4 results in *more* investment than the base case (e.g., due to investment that would otherwise have occurred earlier under the base case being deferred).

Figure 7-4: Difference in cumulative capacity built with Option 4, compared to the base case, under the step-change scenario



7.2. Progressive change scenario

The progressive change scenario is summarised by AEMO as 'pursuing an economy-wide net zero emissions 2050 target progressively, ratcheting up emissions reduction goals over time'. The progressive change scenario delivers the decarbonisation objectives of Australia's Emissions Reduction Plan, with a progressive build-up of momentum ending with significant reductions in emissions from the 2040s. Electric vehicles become more prevalent over time and consumers gradually switch to using electricity to heat their homes and businesses.[61]

Under these assumptions, Option 4 is found to be the top-ranked option with estimated net market benefits of $35 million. Option 1A is the second-ranked option with estimated net market benefits of $25 million. All other options fall substantially behind Option 4 and Option 1A and result in net costs (with the exception of Option 3, which has a marginally positive net benefit).

Figure 7-5 shows the overall estimated net benefit for each option under the progressive change scenario.

[61] AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 27.

Figure 7-5: Summary of the estimated net benefits under the progressive change scenario

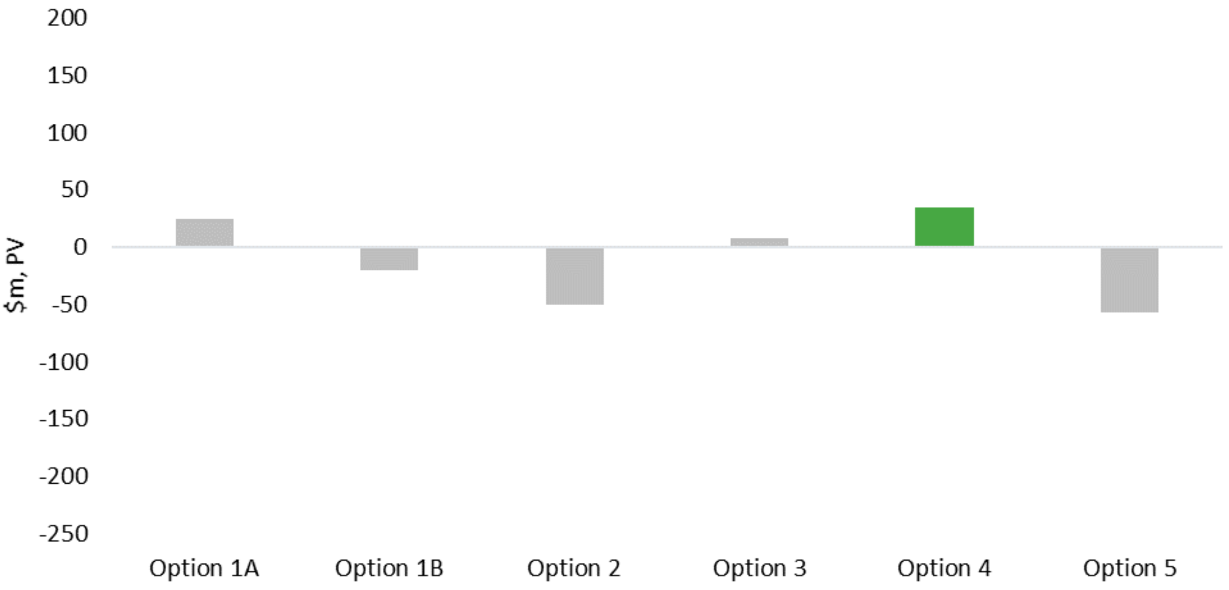
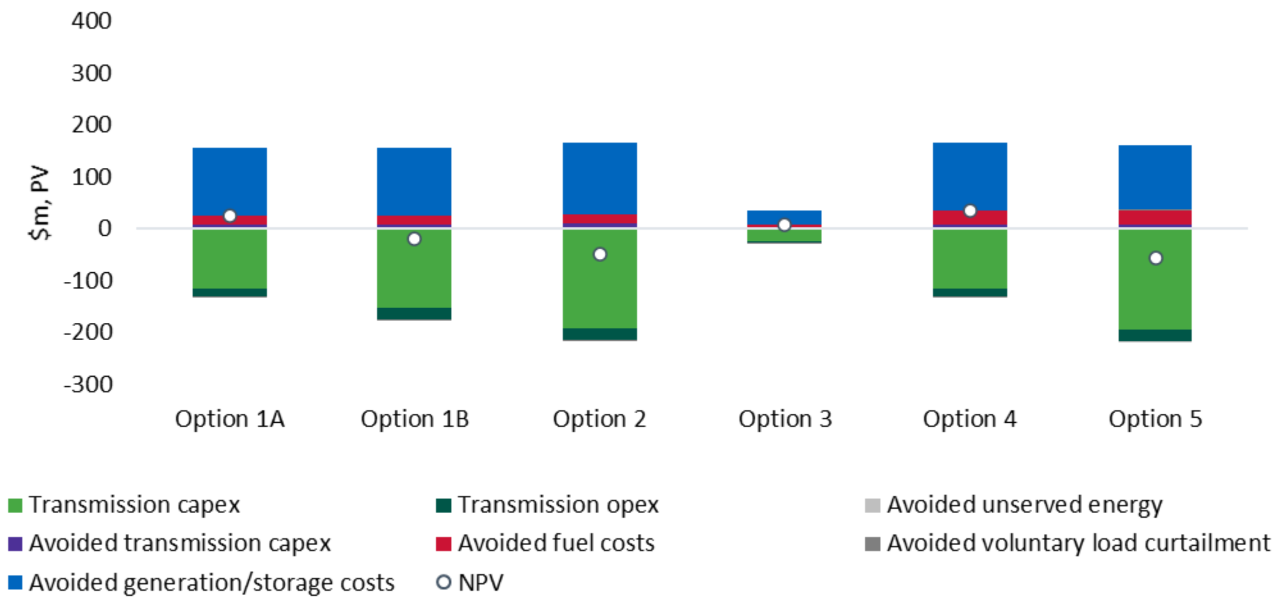


Figure 7-6 shows the composition of estimated net benefits for each option under the progressive change scenario.

Figure 7-6: Breakdown of estimated net benefits under the progressive change scenario



As with the step-change scenario, the largest source of estimated market benefits for the options comes from avoided and deferred costs for new generation and storage. However, the level of these benefits is lower than for the step-change scenario, which is driven by the lower demand in this scenario as well as no carbon budget constraint before 2029/30 (which results in a lower level of coal retirement in this scenario and thus a lower need for new investment, particularly renewable investment).

The progressive change scenario also has a reasonably significant level of avoided fuel costs. This is due to the lower level of coal retirement in this scenario and the fact that the options enable the dispatch of this coal generation to be displaced by renewable generation in south-western NSW.

Figure 7-7 below presents the estimated cumulative expected gross benefits for Option 4 for each year of the assessment period under the progressive change scenario. It shows that the benefits accrue more gradually than the step-change scenario, with the majority of the overall benefits having accrued by the mid-2030s under this scenario.

Figure 7-7: Breakdown of cumulative gross benefits for Option 4 under the progressive change scenario

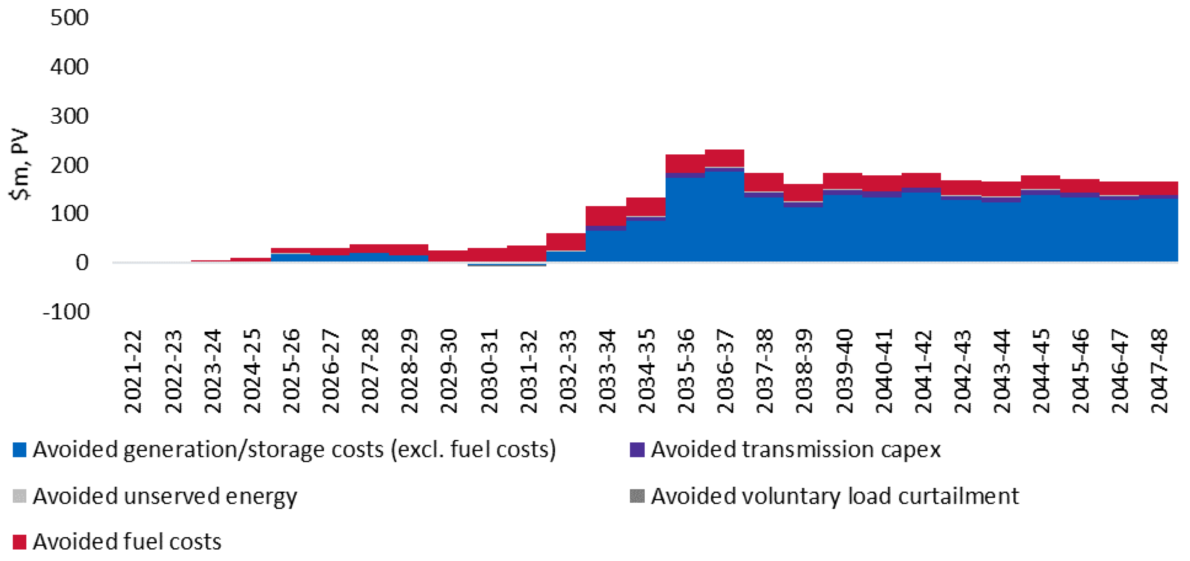


Figure 7-8 summarises the difference in generation and storage capacity modelled for Option 4 (in MW), compared to the base case, i.e., what is found to be driving the avoided or deferred costs associated with generation and storage benefit.

Figure 7-8: Difference in cumulative capacity built with Option 4, compared to the base case, under the progressive change scenario

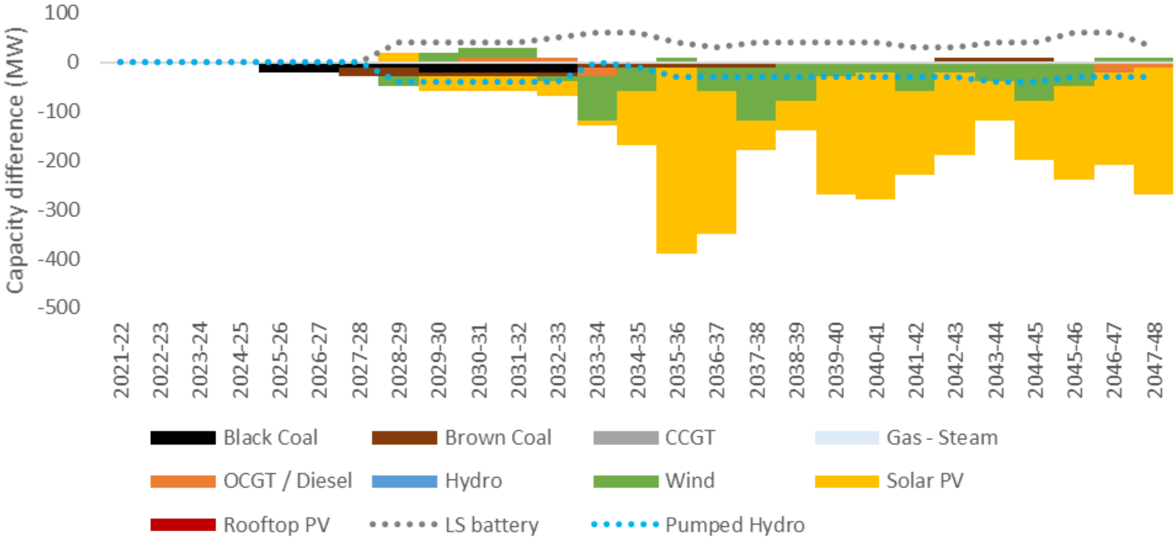
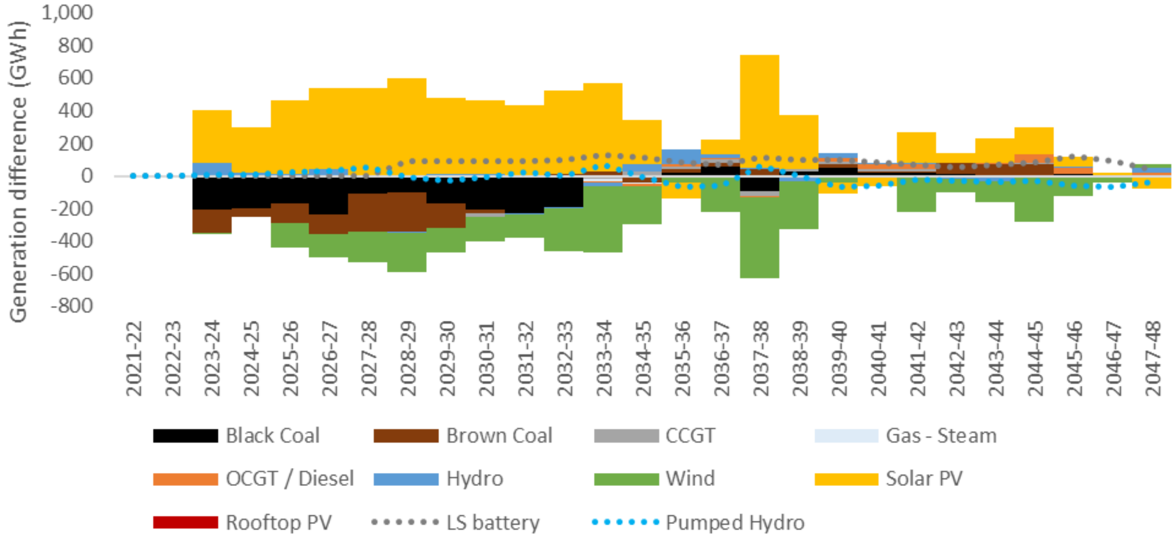


Figure 7-9 summarises the difference in generation and storage output modelled for Option 4 (in GWh), compared to the base case, i.e., what is found to be driving the avoided fuel cost benefit.

Figure 7-9: Difference in output with Option 4, compared to the base case, under the progressive change scenario



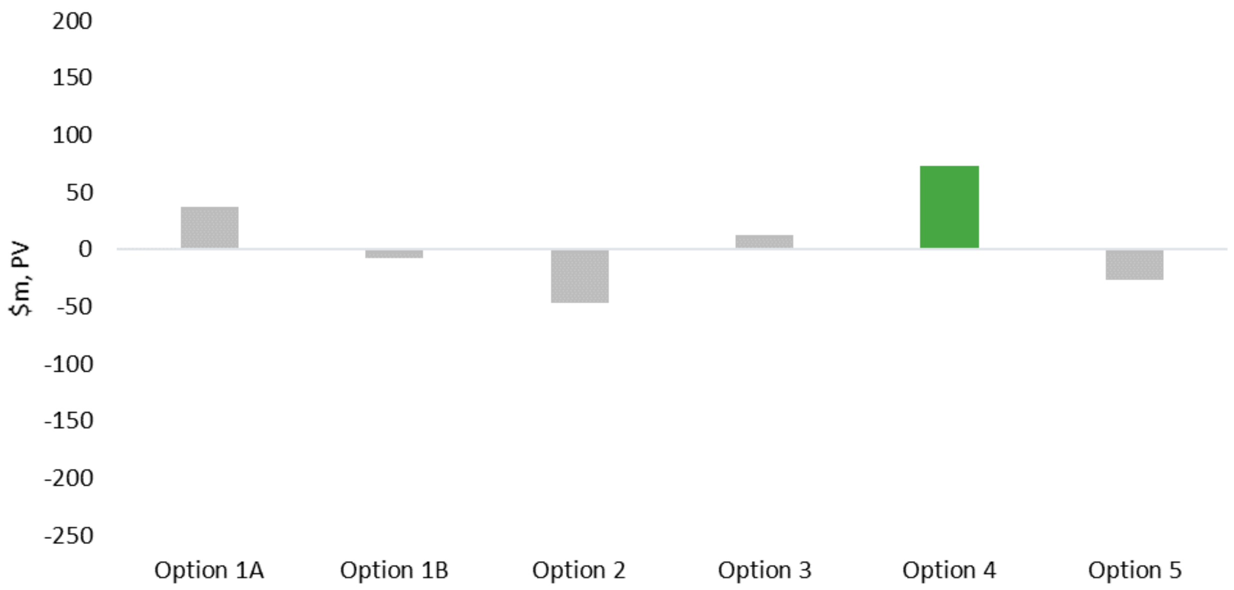
7.3. Hydrogen superpower scenario

The hydrogen superpower scenario is summarised by AEMO as ‘strong global action and significant technological breakthroughs’. While the two previous scenarios assume the same doubling of demand for electricity to support industry decarbonisation, the hydrogen superpower scenario nearly quadruples NEM energy consumption to support a hydrogen export industry. Households with gas connections progressively switch to a hydrogen-gas blend, before appliance upgrades achieve 100 per cent hydrogen use under this scenario.[62]

Under these assumptions, Option 4 is found to be the top-ranked option with estimated net market benefits of $73 million. Option 1A is the second-ranked option with estimated net market benefits of $37 million. All other options fall substantially behind Option 4 and Option 1A (with Option 2 and Option 5 yielding significant net costs).

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

Figure 7-10: Summary of the estimated net benefits under the hydrogen superpower scenario

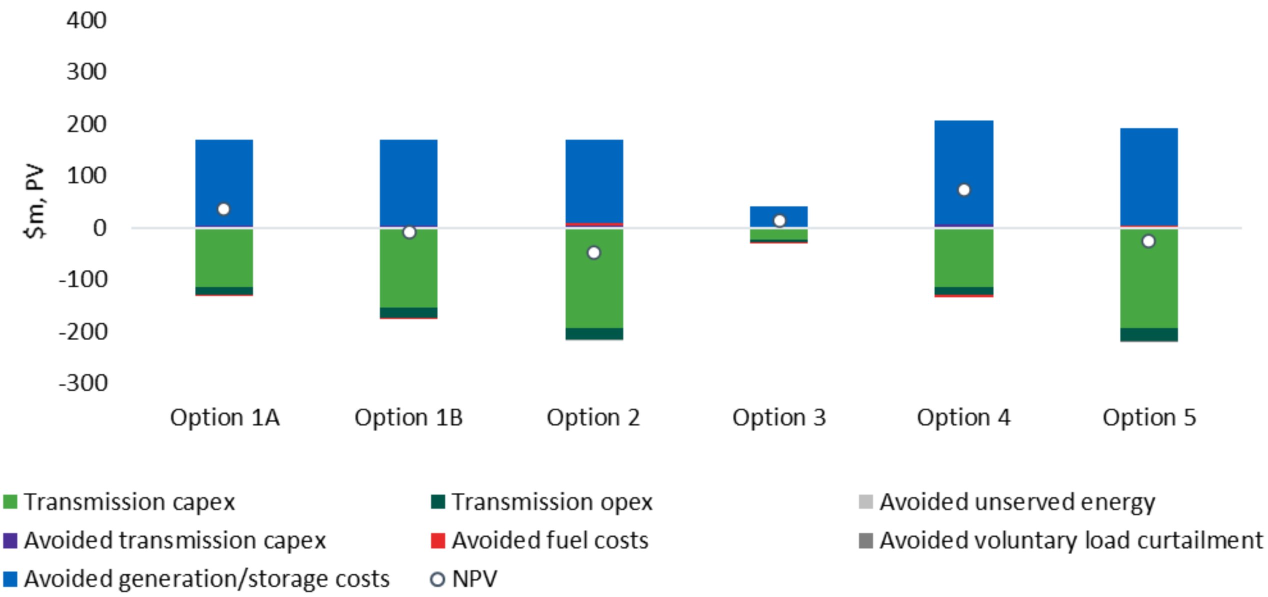


The hydrogen superpower scenario has lower estimated gross market benefits than the step-change scenario (and is more in-line with the progressive change scenario). This is driven by the relatively high demand in all regions for the hydrogen superpower scenario as well as how demand increases significantly from the late 2020s. Specifically, the higher Victorian demand due to significant hydrogen load results in a higher right-hand side of Line 63 stability constraint and, as such, lower binding time for the constraint in the base case. This results in the credible options having less opportunity to accrue benefits from relieving the constraint under this scenario, compared to the step-change scenario.

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

[62] AEMO, *Draft 2022 Integrated System Plan*, December 2021, p. 27.

Figure 7-11: Breakdown of estimated net benefits under the hydrogen superpower scenario



As with the step-change scenario, the vast majority of the estimated market benefits for the options comes from avoided and deferred costs for new generators (primarily solar generation).

Figure 7-12 below presents the estimated cumulative expected gross benefits for Option 4 for each year of the assessment period under the hydrogen superpower scenario. It shows that the majority of the overall benefits has accrued by the late-2020s under this scenario.

Figure 7-12: Breakdown of cumulative gross benefits for Option 4 under the hydrogen superpower scenario

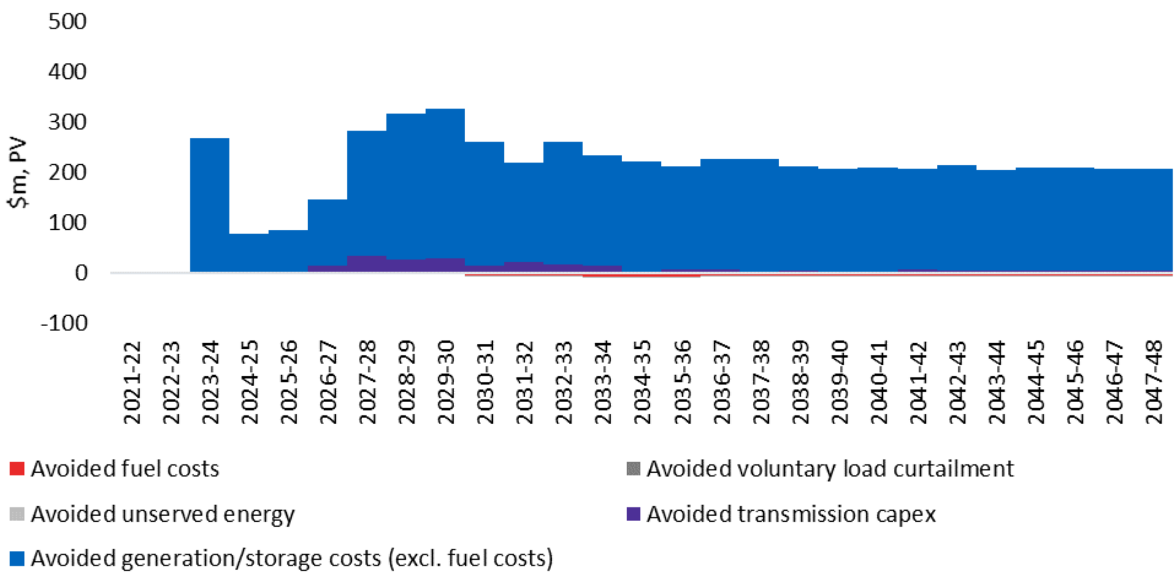
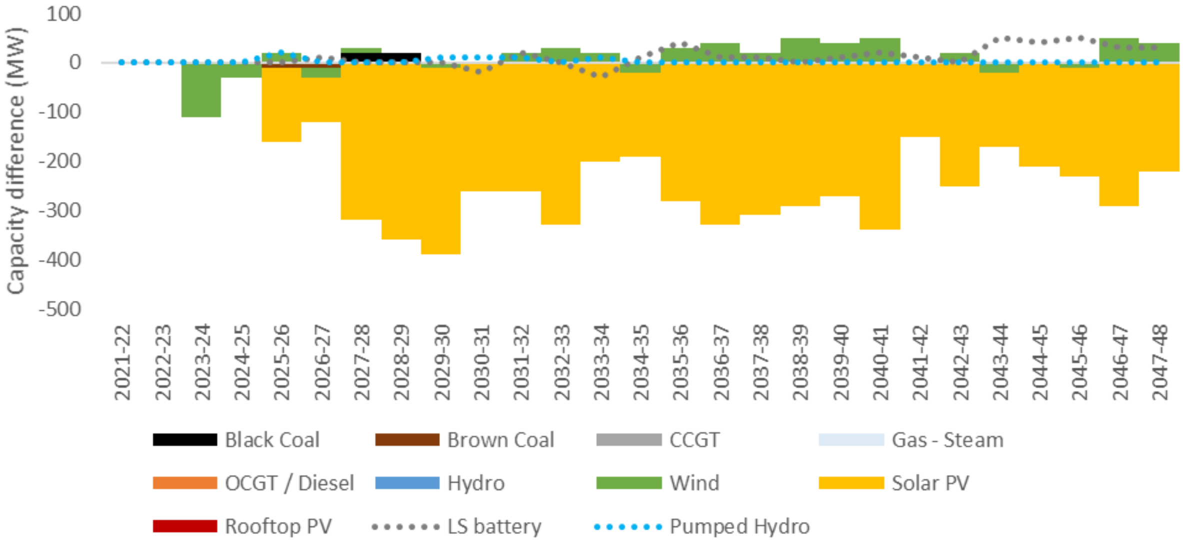


Figure 7-13 summarises the difference in generation and storage capacity modelled for Option 4 (in MW), compared to the base case, i.e., what is found to be driving the avoided or deferred costs associated with generation and storage benefit.

Figure 7-13: Difference in cumulative capacity built with Option 4, compared to the base case, under the hydrogen superpower scenario

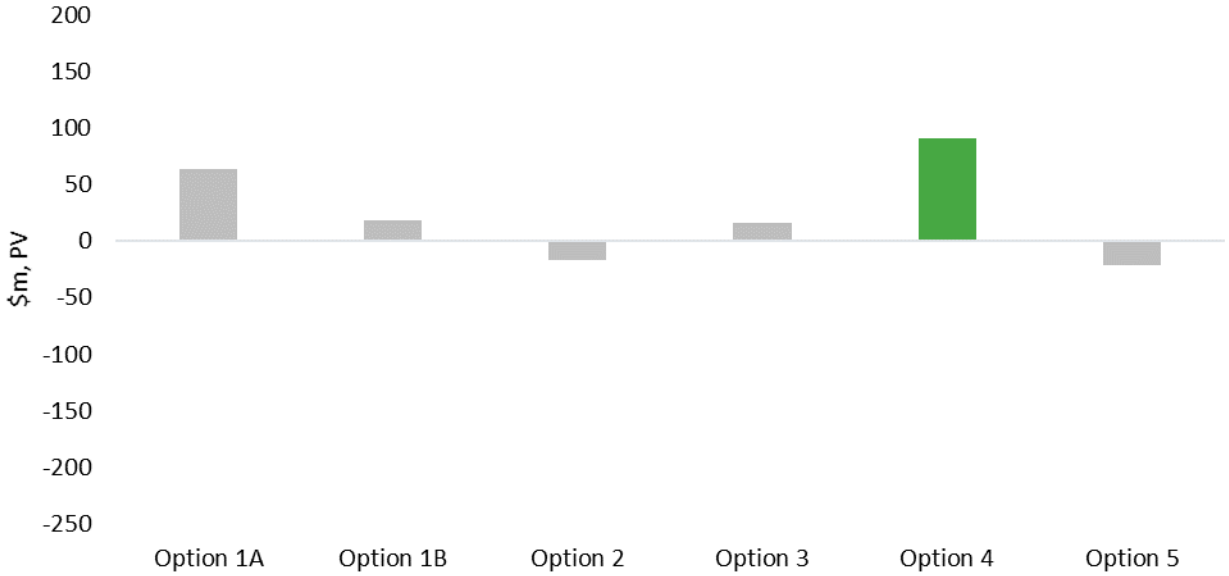


7.4. Weighted net benefits

Figure 7-14 shows the estimated net benefits for each of the credible options weighted across the scenarios investigated (and discussed above).

Under the weighted outcome, Option 4 is the top-ranked option and is found to result in an estimated net benefit of $91 million overall. Option 1A is ranked second with an estimated net benefit of $63 million and all other options fall substantially behind the top two options.

Figure 7-14: Summary of the estimated net benefits, weighted across the scenarios



7.5. Sensitivity analysis

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing. These tests all relate to the weighted net benefits, unless stated otherwise.

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

- the impact of the temporary SPS funded by a proponent;
- changes in the capital costs of the credible options; and
- alternate commercial discount rate assumptions.

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

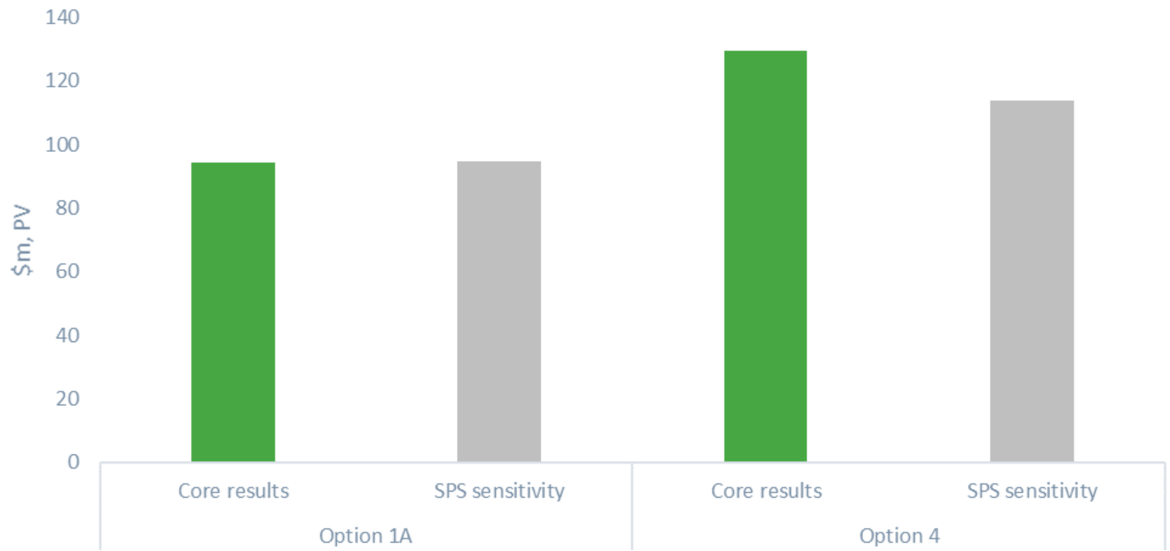
7.5.1. The effect of the interim SPS

As outlined in section 2.1.5, the constraint on Line 63 was relieved in December 2021 by around 200 MW (depending on system conditions) following Transgrid commissioning a temporary SPS funded by a generator in the area. The generator proposed the SPS as a temporary measure only until a long-term solution can be put in place. Transgrid accepted and implemented the SPS as a temporary measure (i.e., until a longer-term solution can be commissioned) as it is not considered to meet long-term network design standards. In light of the SPS being funded by the proponent as a short-term measure until the optimal long-term solution can be identified and put in-place following this RIT-T, we have not included it in the core market modelling undertaken for this PACR.

This sensitivity investigates the expected effect of the temporary SPS on the ranking of the options. Specifically, it increases the limits on Line 63 until 2025/26, consistent with the temporary SPS, and tests whether this alters the conclusion of this PACR under the step-change scenario.

Figure 7-15 shows that, while the net benefits of Option 1A and Option 4 decrease with the temporary SPS assumed, the ranking between the options does not change. Option 4 and Option 1A are also still expected to deliver significant net benefits with the SPS in place (of $114 million and $95 million. respectively).

Figure 7-15: Impact of the temporary SPS, step-change scenario



The finding that Option 4 continues to have greater expected net benefits than Option 1A confirms that the temporary BESS in Option 4 is expected to be net beneficial, i.e., it is expected to provide net benefits, even with the temporary SPS in place.

The relative impact on the expected net benefits of Option 1A and Option 4 from the temporary SPS is expected to be similar in the other two scenarios. Specifically, while assuming the temporary SPS is expected to reduce the net market benefit of Option 4 under these scenarios by a greater amount than for Option 1A, it is not expected to be so great as to affect the relative ranking of the options (as is shown above for the step-change).

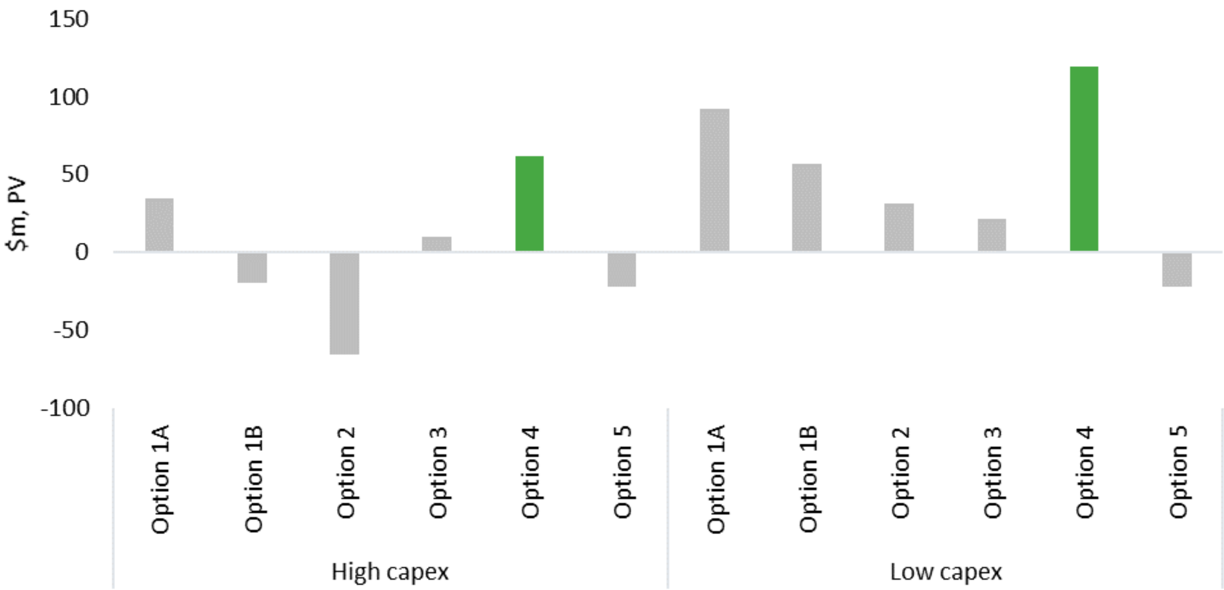
7.5.2. Changes in the capital costs of the credible options

We have tested the sensitivity of the results to the underlying capital costs of the credible options.

It is considered reasonable to expect any factors affecting the network capital costs equally but not necessarily the BESS option (Option 5) due to the fundamentally different underlying cost drivers. Figure 7-16 shows both 25 per cent higher and 25 per cent lower assumed capital costs for all options besides Option 5 and shows that Option 4 remains the top-ranked option under both sensitivities (with Option 1A ranked second).[63]

[63] While the costs presented in this PACR have been refined from the PADR (as outlined in section 4), we still consider them to be at a +/-25 per cent level of accuracy. The next major step in cost estimation that will mark a change (increase) in the accuracy of the cost estimates is the procurement process for the preferred option, which occurs after the RIT-T.

Figure 7-16: Impact of 25 per cent higher and lower network capital costs, weighted NPVs



Looking at Option 4 on its own, 'boundary testing' finds that the central estimates of capital costs (i.e., the capital cost of Option 1A) would need to increase by around 79 per cent in order for Option 4 to have negative net benefits on a weighted basis. We do not consider this likely in light of the refined cost estimates presented in this PACR and so do not consider the preferred option to be sensitive to the assumed capital costs.

We also find that the central estimates of capital costs for Option 1A would need to increase by around 55 per cent in order for Option 1A to have negative net benefits on a weighted basis. We also do not consider this likely in light of the refined cost estimates presented in this PACR.

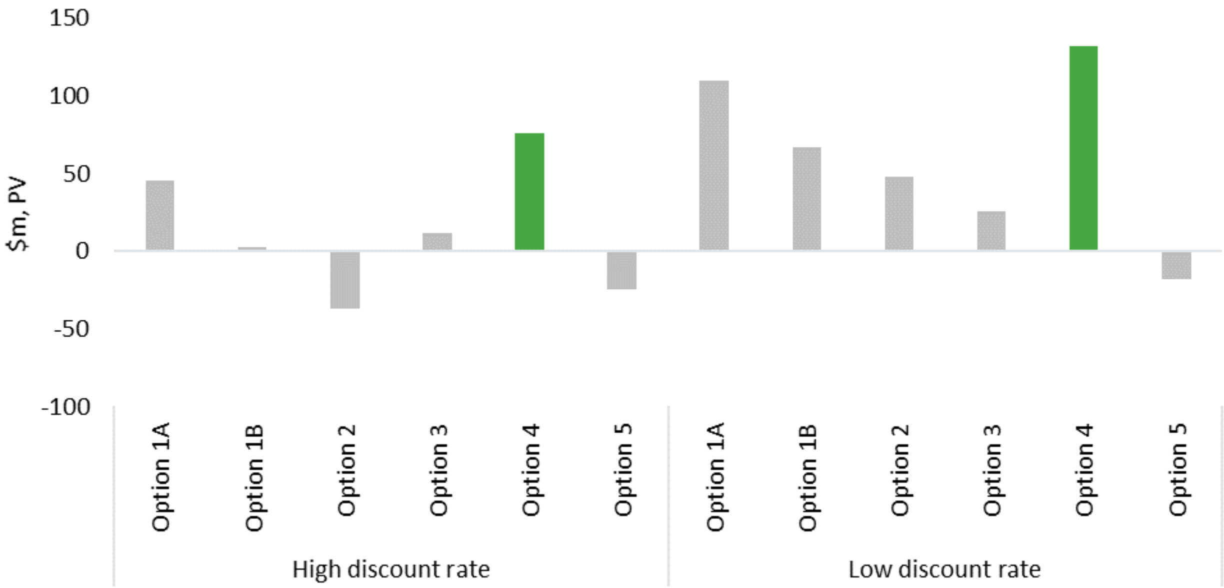
In addition, recognising that BESS have different cost drivers to the traditional network elements, we have also investigated a sensitivity on the BESS costs assumed for Option 5 and find that, even with 50 per cent lower assumed capital costs, Option 5 would not become the preferred option. Extending this sensitivity, we find that the assumed BESS costs would need to fall by more than 50 per cent in order for Option 5 to become the preferred option, which we do not consider to be realistic.

7.5.3. Alternate commercial discount rate assumptions

Figure 7-17 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 7.50 per cent; and
- a low discount rate of 1.96 per cent.

Figure 7-17: Impact of different assumed discount rates, weighted NPVs



Under the high discount rate sensitivity, Option 4's net benefits decrease by $15 million, or about 17 per cent, on a weighted basis compared to net benefits under a central discount rate of 5.50 per cent. Under the low discount rate sensitivity, the net benefits of Option 4 increase by $41 million, or 45 per cent, compared to net benefits under the central discount rate. Under both sensitivities, Option 4 remains the top-ranked option (with Option 1A the second-ranked option).

'Boundary testing' finds that the discount rate would need to be greater than 73 per cent in order for Option 4 to have negative net benefits and greater than 18 per cent in order for Option 1A to have negative net benefits. These discount rates are not considered realistic.

8. Conclusion

This RIT-T finds that a new Darlington Point to Dinawan 330 kV transmission line coupled with an interim 3-year BESS solution ('Option 4') is the preferred option for meeting the identified need across all scenarios and sensitivities assessed. Option 4 is expected to deliver approximately $91 million in net benefits over the assessment period (on a weighted-basis).

The high-level scope of Option 4 involves:

- utilising a BESS development that is currently going ahead independent of this RIT-T (i.e., it is considered 'committed' under the RIT-T) to provide interim network support from 2023-24; and
- the establishment of a new greenfield transmission line between Darlington Point and the new Dinawan substation (that will be developed as part of EnergyConnect).

The new transmission line by itself is referred to as 'Option 1A' in this PACR and involves:

- construction of a single circuit 330 kV transmission line from Darlington Point to Dinawan (approximately 90 km); and
- installation of new 330 kV switchbays at Darlington Point and Dinawan substations.

Under Option 4, the BESS is expected to provide network support from 2023/24 to 2025/26 (when the new line is expected to be commissioned).

Option 4 is expected to provide net benefits to consumers and producers of electricity and to support energy market transition by allowing for more efficient sharing of generation and storage across the NEM through relieving the constraint on Line 63. The market modelling finds that this defers, or avoids, significant costs associated with the construction of new, more expensive generation and/or storage capacity in the NEM in all three scenarios assessed in this PACR. Under the progressive change scenario, it also provides significant avoided fuel costs in the NEM through avoiding the use of higher cost generators to meet demand.

The estimated capital costs of the network elements of Option 4 are $166.9 million. The proposed annual network support cost (opex), which is still to be subject to final negotiation, is $3.25 million/year for the three years of support. The network support component has no incremental capital costs compared to the base case (since it is considered 'committed').

While the ability of the BESS component to relieve the constraint still requires full technical feasibility to be confirmed and agreed with AEMO, we consider Option 4 a 'no regrets' option at this stage. Specifically, should the BESS not be found able to address the constraint, ahead of the new line being commissioned, Option 1A will be considered the preferred option and will proceed on the same timing as the identical network component in Option 4.

Both Option 4 and Option 1A are expected to generate sufficient benefits to recover their costs within five years of commissioning the new line in the step-change and hydrogen superpower scenarios, and within ten years in the progressive change scenario.

In terms of capital costs, we find that they would need to increase by approximately 79 per cent in order for Option 4 to have negative expected net benefits, and 55 per cent for Option 1A. We do not consider this likely in light of the refined cost estimates presented in this PACR. If future cost estimates were to increase by this much, it would be likely to constitute a 'material change in circumstances' under the RIT-T (i.e., under clause 5.16.4(z3) of the NER) that would trigger re-application of the RIT-T.

This RIT-T also considered a brownfield option (Option 1B) to rebuild existing transmission lines.[64] As noted, the outcome of the RIT-T is that Option 4, which involves a greenfield lines component (i.e. Option 1A), has the highest net market benefits. Despite this, we note that the brownfield option (Option 1B) is more consistent with Transgrid's overall general preference for brownfield investments.

Importantly, for greenfield transmission line investments, the RIT-T does not address line route specifics for the preferred option.[65] These are scoped by the TNSP and assessed within the Environmental Impact Statement (EIS). Planning approval would only be granted by the NSW Minister for Planning and Public Spaces following extensive, genuine community and stakeholder consultation and demonstration that environmental impacts can be effectively managed or mitigated. This process will commence following the conclusion of this RIT-T.

[64] 99T Darlington Point to Coleambally and 99L Coleambally to Deniliquin as 330 kV to Dinawan

[65] Instead, the RIT-T approval process reviews, and publicly consults on, a TNSP's application for new investment to meet an identified need. Overall, it identifies the technical solution to the need that provides the greatest net benefit to the NEM overall. This RIT-T process is undertaken in consultation with consumers, AEMO, Registered Participants and other interested parties regarding the investment options under consideration.

Appendix A Compliance checklist

This section sets out a compliance checklist which demonstrates the compliance of this PACR with the requirements of clause 5.16.4(v) of the National Electricity Rules version 180.

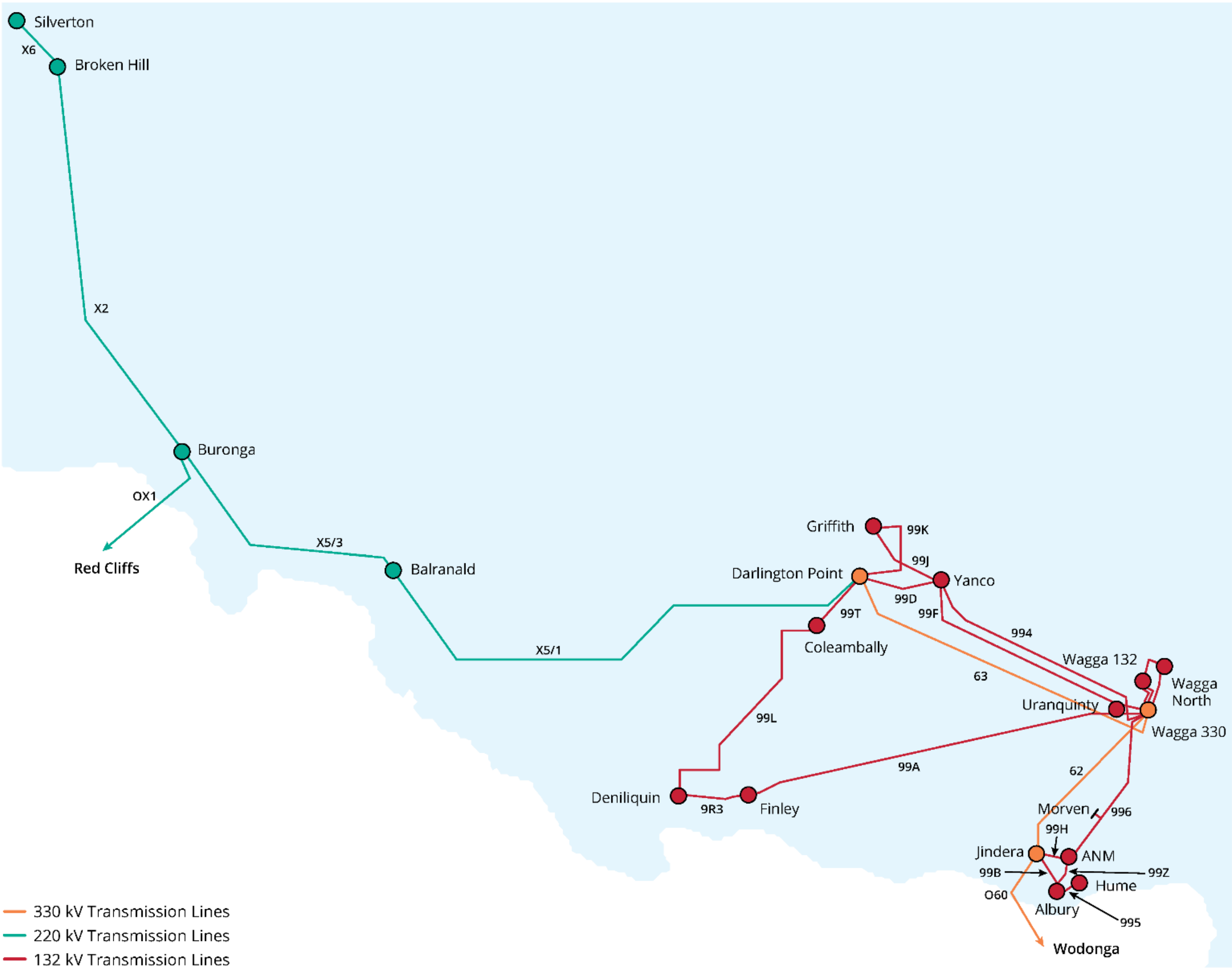
Rules clause	Summary of requirements	Relevant section(s) in the **PACR**
5.16.4(v)	The project assessment conclusions report must set out:	-
	(1) the matters detailed in the project assessment draft report as required under paragraph (k)	See below.
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought	3
5.16.4(k)	The project assessment draft report 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;	See PADR.
	(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, 6 & 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);	6
	(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, Limondale 2 (29 MW) in 2020, and Sunraysia (200 MW) in December 2021.

Further connections are progressing with commissioning scheduled during 2021-22 for the Darlington Point Solar Farm (275 MW), Limondale 1 Solar Farm (220 MW) and Hilston Solar Farm (85 MW).

In summary, there has been more than 790 MW of renewable generation has connected in the area since December 2015 and approximately 580 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 July 2025.[66]
- 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.
  - Early works are expected to be completed by 2026 with wider implementation, so long as the project passes decision rules that demonstrate consumers will continue to benefit from the project, by July 2031.[67]

In September 2021, the Federal government announced it had reached an agreement with Transgrid to improve the capacity of the transmission network in south-western NSW. Under the agreement, the government will provide up to $181.5 million in underwriting support to enable transmission lines being built from south at Dinawan to Wagga Wagga as part of enabling this section of EnergyConnect to be constructed at a larger capacity than originally planned.[68]

The agreement followed Transgrid revising the preferred route for EnergyConnect slightly as a result of design optimisation whereby a new substation at Dinawan was included. The revised route now features a more direct path from Buronga to Wagga Wagga and no longer diverts via the existing Darlington Point substation.

The agreement enables the Dinawan to Wagga Wagga portion of EnergyConnect to be built to be operated at 500 kV when required, but initially operated at 330 KV (as originally planned). A key trigger for operation of this section at 500 kV would be the identification of KerangLink as the preferred option for VNI West as part of the current VNI West RIT-T.

While both EnergyConnect and VNI West 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 PACR).

66 AER, *Transgrid Contingent Project EnergyConnect*, Final Decision, May 2021, p. 1.
67 AER, *Transgrid Contingent Project EnergyConnect*, Final Decision, May 2021, p. 1.
68 https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmission-infrastructure-southwest-nsw

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 B-5 summarises the various new generation developments expected to connect in south-western NSW.

Table B-5: 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
Hillston Solar Farm	2021 (being commissioned)	85 MW
Avonlie Solar Farm	2021 (committed)	160 MW
Yanco Solar Farm	2021 (committed)	60 MW
Additional submitted connection applications	2021-2022	543 MW (in aggregate)
Additional submitted connection applications	2022-23	450 MW (in aggregate)

Appendix C Overview of the wholesale market modelling undertaken

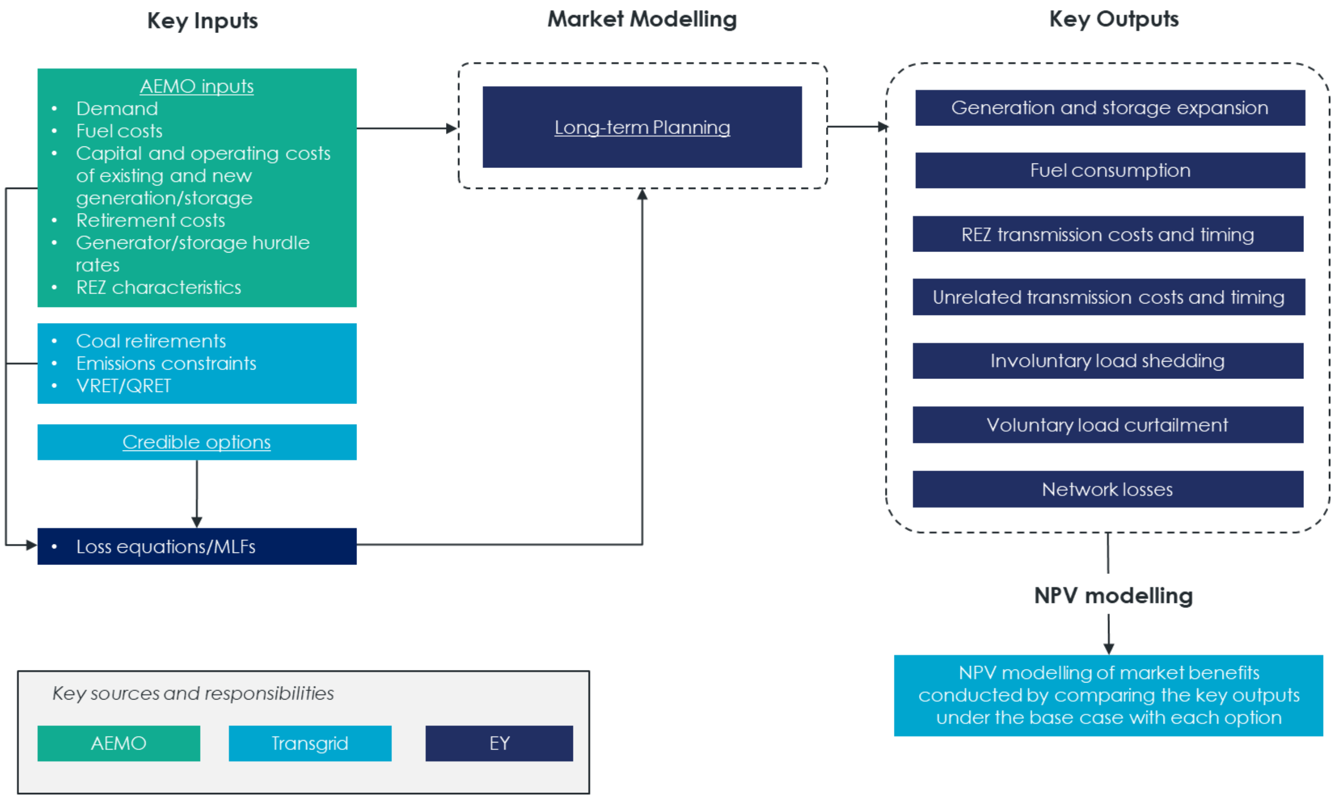
As outlined in the body of this PACR, we have engaged EY to undertake the wholesale market modelling as part of this PACR.

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 reserve 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.

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



The sub-sections below provide additional detail on the key wholesale market modelling exercises EY have undertaken as part of this PACR 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, emissions reduction and renewable energy targets, 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 unplanned and planned 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 BESS 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;
- regional and mainland reserve requirements are met;
- energy-limited generators such as Tasmanian hydro-electric generators, Snowy Hydro-scheme and grid-scale batteries 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 2022 ISP (and was applied in the 2020 ISP and the inaugural 2018 ISP).[69]

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. 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 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.

[69] 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.

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-6: PACR modelled scenario's key drivers input parameters

Key drivers input parameters	Step change	Progressive change	Hydrogen superpower
Underlying consumption	ESOO 2021 (draft ISP 2022) – step change	ESOO 2021 (draft ISP 2022) – progressive change	ESOO 2021 (draft ISP 2022) – hydrogen superpower
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PSH, and large-scale batteries	2021 Inputs and Assumptions Workbook – step change	2021 Inputs and Assumptions Workbook – progressive change	2021 Inputs and Assumptions Workbook – hydrogen superpower

Key drivers input parameters	Step change	Progressive change	Hydrogen superpower
Retirements of coal-fired power stations	2021 Inputs and Assumptions Workbook – step change In line with expected closure year, or earlier if economic or driven by decarbonisation objectives	2021 Inputs and Assumptions Workbook – progressive change In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030	2021 Inputs and Assumptions Workbook – hydrogen superpower In line with expected closure year, or earlier if economic or driven by decarbonisation objectives
Gas fuel cost	2021 Inputs and Assumptions Workbook – step change Lewis Grey Advisory 2020, step change	2021 Inputs and Assumptions Workbook – progressive change Lewis Grey Advisory 2020, central	2021 Inputs and Assumptions Workbook – hydrogen superpower Lewis Grey Advisory 2020, step change
Coal fuel cost	2021 Inputs and Assumptions Workbook – step change Wood Mackenzie, step change	2021 Inputs and Assumptions Workbook – progressive change Wood Mackenzie, central	2021 Inputs and Assumptions Workbook – hydrogen superpower Wood Mackenzie, step change
NEM carbon budget to achieve 2050 emissions levels	2021 Inputs and Assumptions Workbook – step change 891 Mt CO_2-e 2023-24 to 2050-51	2021 Inputs and Assumptions Workbook – progressive change 932 Mt CO_2-e 2030-31 to 2050-51	2021 Inputs and Assumptions Workbook – hydrogen superpower 453 Mt CO_2-e 2023-24 to 2050-51
Victoria Renewable Energy Target (VRET)	40 % renewable energy by 2025 and 50 % renewable energy by 2030 VRET 2 including 600 MW of renewable capacity by 2025		
Queensland Renewable Energy Target (QRET)	50 % by 2030		
Tasmanian Renewable Energy Target (TRET)	2021 Inputs and Assumptions Workbook: 200 % Renewable generation by 2040		
NSW Electricity Infrastructure Roadmap	2021 Inputs and Assumptions Workbook: 12 GW NSW Roadmap, with 3 GW in the Central West Orana (CWO) REZ, modelled as generation constraint per the draft 2022 ISP 2 GW of long duration storage (8 hrs or more) by 2029-30		
EnergyConnect	Draft 2022 ISP – EnergyConnect commissioned by July 2025		
Western Victoria Transmission Network Project	Draft 2022 ISP – Western Victoria upgrade commissioned by November 2025		
HumeLink	Draft 2022 ISP – step change: HumeLink commissioned by July 2028	Draft 2022 ISP – progressive change: HumeLink commissioned by July 2035	Draft 2022 ISP – hydrogen superpower: HumeLink commissioned by July 2027
Marinus Link	Draft 2022 ISP – 1st cable commissioned by July 2029 and 2nd cable by July 2031		
Victoria to NSW Interconnector Upgrade (VNI Minor)	Draft 2022 ISP – VNI Minor commissioned by December 2022		
NSW to QLD Interconnector Upgrade (QNI Minor)	Draft 2022 ISP – QNI minor commissioned by July 2022		
QNI Connect	Draft 2022 ISP – step change: QNI Connect commissioned by July 2032	Draft 2022 ISP – progressive change: QNI Connect commissioned by July 2036	Draft 2022 ISP – hydrogen superpower: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030
VNI West	Draft 2022 ISP – step change: VNI West commissioned by July 2031	Draft 2022 ISP – progressive change: VNI West commissioned by July 2038	Draft 2022 ISP – hydrogen superpower: VNI West commissioned by July 2030
Victorian SIPS	Draft 2022 ISP – 300 MW/450 MWh, 250 MW for SIPS service and the remaining 50 MW can be deployed in the market by the operator on a commercial basis, November 2021.		

Key drivers input parameters	Step change	Progressive change	Hydrogen superpower
New-England REZ Transmission	Draft 2022 ISP – step change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	Draft 2022 ISP – progressive change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	Draft 2022 ISP – hydrogen superpower: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2031, and stage 3 by July 2042
Snowy 2.0	2021 Inputs and Assumptions Workbook – Snowy 2.0 is commissioned by December 2026		

Appendix D Summary of consultation on the PADR

This appendix provides a summary of points raised by stakeholders during the PADR consultation process, besides those raised in confidential submissions.

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

A similar table was included in the PADR for submissions received on the PSCR (see Appendix D of the PADR). We note that some of the points summarised in that appendix have been superseded by analysis in the current PACR.

Table D-7 – Summary of consultation on the PADR

Summary of comment(s)	Submitter(s)	Our response
Support for the identified need		
The constraint represents a significant financial impact for generators and one which leads to increased risk premiums for future investments. Given the additional generation planned for this region, the problem will persist and will continue to worsen until system upgrades can be implemented.	Darlington Point Solar Farm Pty Ltd, p. 1	The financial impacts on generators are noted. All options assessed in this PACR strengthen the transmission network to relieve the constraint and we note that the RIT-T is being undertaken as expeditiously as possible to minimise the impact on affected parties.
The constraint represents a significant financial impact on projects and one which was not foreseen (whether by us, AEMO or Transgrid) at the time our project was committed.	RWE Renewables Australia Pty Ltd, p. 1	
The RIT-T provides a strong message to investors and banks for projects in the Riverina that the transmission system operational constraints will be addressed so that the grid system is able to operate in a stable manner and maximise the flow of electricity of the existing transmission infrastructure.	Reach Solar Energy Co Pty Ltd, p. 2	All options assessed in this PACR strengthen the transmission network to relieve the constraint.
Constraints are currently being used to curtail large amounts of low-cost renewable generation in order to manage this part of the network. This represents a lost opportunity for consumers to benefit through lower electricity prices in NSW.	Darlington Point Solar Farm Pty Ltd, p. 1	All options assessed in this PACR strengthen the transmission network to relieve the constraint. The preferred option is found to deliver significantly positive net market benefits to the NEM, which are expected to result in lower electricity bills to consumers compared to the 'do nothing' base case.
Given that the constrained generation is low-cost renewables, it represents a lost opportunity for consumers to benefit through lower electricity prices in NSW.	RWE Renewables Australia Pty Ltd, p. 1	
The expanded transmission capacity will help unlock additional renewable energy in the area, reducing emissions, and delivering lower costs to consumers.	Iberdrola Australia Limited, p. 1	
We consider the Yarrabee Solar project will provide both direct and indirect benefits via local employment and engagement with businesses throughout the region.	Narrandera Shire Council, p. 1	See section 3.1

Summary of comment(s)	Submitter(s)	Our response
The new transmission facility will create the stimulus for the ongoing development of renewable energy projects in the region offering local farmers the opportunity to diversify their income e.g. land rent, and increase community benefits to the townships within the Riverina District.	(Letter submitted to/with the Reach Solar Energy Co submission)	
Current cost recovery arrangements		
We reject the proposal under current cost recovery arrangements, which would require consumers to pay for the proposed network upgrades. Generation businesses, not consumers, are the primary beneficiaries of the upgrades proposed.	Public Interest Advocacy Centre, p. 1	See section 3.2
Transgrid should seek funding from those generation businesses if it considers the upgrades have merit. The revenue benefit for generators will be greater than the wholesale market benefits for consumers and, if generators are unwilling to fund the upgrades, this casts doubt on Transgrid's estimates of costs and benefits. Transgrid has persistently and significantly underestimated costs and, in PIAC's view, exaggerated the benefits of its proposed major transmission projects.	Public Interest Advocacy Centre, p. 1	
Support for specific credible options in the PADR		
We are supportive of Option 1A and encourage Transgrid to proceed as quickly as possible.	Iberdrola Australia Limited, p. 1	Option 4, which involves the same network elements as Option 1A, is found to deliver the greatest level of net market benefits (and gross market benefits) of all options and is the preferred option under this RIT-T (as outlined in section 8).
Supports Option 1A.	Reach Solar Energy Co Pty Ltd, p. 1	
We note that Option 2 provides the greatest gross benefits, and we would support that option if its costs could be reduced. However, on an analysis of net benefits, Option 1A presents as the best overall solution, with the lower gross benefits offset by the lower capex.	RWE Renewables Australia Pty Ltd, p. 1	
Feasibility of BESS options		
The PADR Options 4 and 5 do not provide cost estimates and, based on review by our technical advisors, are not likely to provide a complete solution to the 'identified need'. The economic and risk assessment	Reach Solar Energy Co Pty Ltd, p. 2	See section 3.3

Summary of comment(s)	Submitter(s)	Our response
analysis should consider the transmission line solutions versus non network solutions (NNS) on a 'like-for like' basis i.e.: a. The NNS energy storage system should be evaluated at the energy storage (MWh) required to restore Line 63 from an expected outage. Recent actual transmission line outages in Victoria and South Australia suggest a minimum of two to three weeks to install temporary towers which equates to 900MW x 24hrs x 14 to 21days = a BESS storage of 302,400 to 453,600 MWh. This renders NNS prohibitive and not comparable to a transmission line solution. b. The NNS asset life should also reflect the transmission line solution asset life of over 40 years (which equates to multiple BESS cell replacements over the project life). c. A transmission line has very high reliability and BESS consists of various sensitive components that will fail over the course of its life. Including operational costs, reliability and required redundancy, the BESS solution would be very expensive and not comparable to a transmission line solution		
Support for interim solutions		
We are very interested in exploring possible interim solutions that can provide relief in the short and medium term.	Darlington Point Solar Farm Pty Ltd, p. 2	See section 3.4
While the PADR found an interim BESS solution to be too costly, we encourage Transgrid to consider any alternative interim solutions, be it through plant settings, protection schemes or otherwise, and would welcome any discussions on alternative options to provide interim relief.	RWE Renewables Australia Pty Ltd, p. 2	
Comments on the scenario analysis		
We note that the NEM is currently projected to move faster than AEMO's 2020 step-change scenario and so only one of the four core scenarios in the PADR are likely to be relevant.	Iberdrola Australia Limited, pp. 1-2	See section 3.5
We consider the step-change to be the most appropriate lens for assessing the costs and benefits of the proposed options.	Darlington Point Solar Farm, p. 1	

Summary of comment(s)	Submitter(s)	Our response
Transgrid should consider the impact of the proposed upgrades in a scenario consistent with NSW and Australia's commitments to net-zero by 2050. Transgrid should analyse scenarios with a much the higher uptake of renewable energy across NSW and, in particular, in the South-Western NSW area. While we support the proposed upgrade, it is important that it does not create new problems for existing and committed investments.	Iberdrola Australia Limited, p. 3	
Avonlie solar farm is now committed at 190 MW-ac (245 MWdc), rather than 160 MW-ac. This also includes approval for a 100 MW DC coupled BESS (not yet committed). We understand the Yanco solar farm south of Griffith is also now committed and may impact on the scenario analysis.	Iberdrola Australia Limited, p. 1	
Future-proofing the options		
Given Australia's renewed commitment to net-zero by 2050, it might also warrant consideration of whether additional reinforcements or investment being made at the same time would be of value to consumers. For example, we have undertaken semi-quantitative analysis that suggests with increased uptake of renewables in the area, the 132 kV lines from Avonlie to Wagga Wagga may be impacted by binding constraints in the event of contingencies on the nearby 330 kV lines or one of the two existing 132 kV lines. We therefore propose that Transgrid consider, potentially amongst other options, an upgrade of the lines between Avonlie and Wagga Wagga to consider potential future projects in the area.	Iberdrola Australia Limited, pp. 2, 3.	See section 3.6
We suggest Transgrid engage with the NSW Government and the Consumer Trustee to consider whether additional future-proofing upgrades to this region would be in the long-term interest of consumers.	Iberdrola Australia Limited, p. 3	See section 3.6
Timetable of the project		
We implore Transgrid to do all in its power to fast-track this RIT-T.	Darlington Point Solar Farm Pty Ltd, p. 2	See section 3.7

Summary of comment(s)	Submitter(s)	Our response
We consider that the RIT-T process should be concluded on an urgent basis.	Reach Solar Energy Co Pty Ltd, p. 2	
We also note Transgrid's comments that it is endeavouring to undertake the RIT-T in as timely a fashion as possible within the confines of the regulatory framework, and we respectfully urge it to continue to do so.	RWE Renewables Australia Pty Ltd, p. 2	
Other comments		
By following the existing transmission line corridor (i.e. Line 63), substantial additional land easements should not be required, and as a such, no additional impact on existing agricultural operations should result.	Narrandera Shire Council, p. 2 (Letter submitted to/with the Reach Solar Energy Co submission	Any transmission line route between Darlington Point and Dinawan will still require a new 60 metre wide easement parallel to the existing transmission line easements (i.e., no overlap between easement edges). Any impacts to existing agricultural operations will be considered as part of the overall transmission line environmental and property assessment processes following the RIT-T.
We understand that there is potential for further capacity constraints in the future, limiting exports even further for generators.	RWE Renewables Australia Pty Ltd, p. 1	There are no further constraints forecast for Line 63 under any of the three scenario base cases or option cases.
Suggest the work is done by the EnergyConnect contractor to save time and leverage from synergies between the two projects. The RIT-T scope for Option 1A is relatively modest (50-70km) and we suggest it be completed in parallel with EnergyConnect by mid-2024. This in turn is likely to produce a least cost solution and also intuitively increase the net benefits of the project. The recent announcement by Transgrid and the Commonwealth Government to fund a $180 million for an upgrade to 500 kV for the EnergyConnect transmission line from Dinawan to Wagga Wagga underscores the benefit from extracting synergies mentioned above.	Reach Solar Energy Co Pty Ltd, p. 1	We would expect any synergies arising from one contractor undertaking both projects to feature in their bid to the competitive procurement process for this project once it commences (assuming they have the capacity and appetite to bid).