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Managing the risk on Line 86 (Tamworth – Armidale)

RIT-T – Project Assessment Conclusions Report

Region: Northern New South Wales

Date of issue: 29 July 2022

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Executive summary

Line 86 is a 330 kV single-circuit line, running between Tamworth and Armidale (111 km), and was constructed in 1982 using mostly composite wood pole[1] structures.[2] Line 86 is the only 330 kV line in our network that was not constructed using steel towers.

Wood rot beneath the composite pole joint sleeve is prevalent throughout the composite wood poles that are utilised along the line. We have replaced, or remediated, 40 poles since 2000, which represents 10 per cent of the original wood poles on Line 86.

Given the expected increasing rate of defect issues, including required pole replacements, and past experience with composite wood pole structures, we consider it is likely that all the remaining wood structures on Line 86 are exhibiting various forms of decay, which is only expected to worsen over time. The deteriorating condition of the wood poles gives rise to bushfire risk and also results in higher expected costs associated with reactive maintenance (which may need to be done under emergency conditions).

This Regulatory Investment Test for Transmission (RIT-T) process was initiated to progress and consult on the assessment of investment options to address the asset condition issues identified on Line 86. This includes assessing whether the benefit expected from proactively avoiding the risks with the deteriorating condition of the wood poles (i.e., ahead of when they fail) is expected to exceed the replacement costs, while providing the greatest overall net benefit to the National Electricity Market (NEM) over the long-term. 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 May 2022.

Overview

The PACR finds that a focused replacement of the highest risk Line 86 wood poles, like for like and in-situ with concrete or steel poles ('Option 1C') is the preferred option for meeting the identified need on a weighted basis and in the sensitivities assessed. Option 1C is expected to deliver approximately $6.2 million in net benefits over the 19-year assessment period (on a weighted-basis), and approximately $5.7 million under the most likely scenario (the central scenario).

Option 1C satisfactorily reduces the bushfire risk posed by the deteriorating poles on Line 86, and avoids significant expected costs associated with reactive maintenance (which may need to be done under emergency conditions).

The PACR assessment shows that the additional costs of replacing Line 86 with either a higher capacity line or in combination with a VTL (i.e., Option 3 and Option 1B, respectively) are not outweighed by the additional wholesale market benefits expected.

Option 1C involves replacing the 31 highest risk poles of Line 86 between 2025-26 and 2027-28 (making up approximately 8 per cent of the remaining poles to be replaced/remediated). The replacement of the remaining poles on Line 86 would be subject to a separate RIT-T in the future to determine whether this work is justified (and in what form).

The estimated capital cost of replacing the 31 highest risk poles of Line 86 under Option 1C is approximately $10.65 million.

1 A composite wood pole consists of a two-piece pole arrangement that is held together by a metal cylinder/sleeve.
2 A short section (3.72km) of the line outside Tamworth is constructed on steel towers.

Benefits from addressing the condition of the Line 86 wood poles

If action is not taken, the condition of the wood poles is expected to expose Transgrid and its customers to unacceptable levels of risk going forward. Specifically, there are significant bushfire risks under the 'do nothing' base case, as well as higher expected costs associated with reactive maintenance that may be required under emergency conditions ('financial risks'). There are also expected to be reputational, safety and reliability risks if the condition of the poles is not addressed but these are small relative to the bushfire and financial risks estimated.

While all of the credible options assessed in this PACR mitigate the risks associated with the condition of the wood poles, they also have the potential to impact the wider wholesale market in various ways, through increasing the network transfer capacity between Tamworth and Armidale. These expected wider wholesale market interactions are primarily due to the interaction with:

- the nearby Queensland to New South Wales Interconnector (QNI), which is currently being upgraded; and
- the New England Renewable Energy Zone (REZ) around Armidale, which is being progressed under the NSW Government's Electricity Infrastructure Roadmap.

Each of the options are expected to affect the wholesale market relative to the base case by reducing the time that Line 86 is out of service due to poles failing.

The larger capacity option (Option 3) and the VTL option (Option 1B) also increase the overall network transfer capacity. These options therefore also have a further impact on the wholesale market, which has been reflected in the analysis in this PACR. However, the assessment finds that either this wider impact results in a negative market benefit (Option 3), or that any additional positive market benefit is outweighed by the additional cost of the option (Option 1B).

Key developments since the PADR that have been reflected in the PACR

The PADR was released in May 2022, with written submissions requested by 15 July 2022. No submissions were received in relation to the PADR.

There have been three key developments since the PADR was released that have affected the analysis of wholesale market benefits in the PACR – namely:

- the final 2022 ISP was published 30 June 2022;
- AEMO released its latest database of committed and anticipated generation projects in the NEM in June 2022; and
- Transgrid and ElectraNet have updated the date that full capacity is expected to be available from EnergyConnect following the completion of inter-regional testing to 1 July 2026.[3]

Each of these have been reflected in the wholesale market modelling presented in this PACR. Specifically, the inputs and assumptions in the PACR wholesale market modelling fully align with the final 2022 ISP, with the exception of the database of committed and anticipated generation projects and the assumed

[3] AEMO, *2022 Integrated System Plan*, June 2022, p. 66, Table 5.

timing of EnergyConnect (both of which reflect the latest information available and were not able to be reflected in the final 2022 ISP).

We have also further considered the appropriate assessment period for this RIT-T, as flagged in the PADR, in light of the expected timing and uncertainty around later stages of investment. In particular, in the PADR the analysis of Option 1C included an indicative second set of pole replacements that is not expected to be required until after 2040 (and would again only focus on the highest risk poles at that time). Given how far into the future this investment is expected to occur, and its indicative nature at this stage, we have taken the approach of truncating the assessment period for the PACR so that it ends in 2040-41 (i.e., before any further investment is expected to be required). Any future program of investment to replace further poles on Line 86 would be subject to a subsequent RIT-T closer to the time.

We note that shortening the assessment period from 27 years to 19 years has the effect of reducing the net benefits of the options because:

- substantial avoided risk cost benefits after 2040-41 are no longer captured in the analysis; and
- any further capital expenditure included towards to the end of the assessment period would have a high terminal value, and so has little impact on the present value of costs in the analysis.

We therefore consider that the 19-year assessment period adopted for the PACR represents a conservative assumption of the net market benefits of the options.

The PACR assessment covers four different credible options

The PACR assesses four different credible options that cover:

- replacing all poles on Line 86 in one go, versus in a targeted manner;
- replacing the poles in-situ and leaving the line capacity the same, versus rebuilding the line at a higher capacity; and
- providing greater capacity to this area of the network through either building a new line, or through coupling the existing line with a VTL.

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

Table E-1: Summary of the credible options

Option	Description	Estimated capital cost ($2021-22)	Expected completion date**	Expected transfer improvement (reduced service outages)***	Expected transfer improvement (higher rating)
Replace Line 86 like for like in-situ utilising concrete or steel poles, keeping the existing twin lime conductor and single circuit configuration, while maintaining the overall design temperature at 100°C					
1A	Replace all (367) poles in one-go	95.7	2027-28	280 MW	-
1B	Replace all (367) poles in one-go and couple with a VTL (2 x 200 MW batteries)	95.7 (for the line) Confidential for the VTL	2027-28 (for the line) 2023-24 (for the VTL)	280 MW	200 MW (from the VTL)
1C	Replace the highest risk structures (31) over 2025-26 to 2027-28; with the remaining structures (336) replaced beyond the assessment period	10.65 (2025-26 to 2027-28)	2028-29	280 MW	-
Rebuild Line 86 as a double circuit with twin olive conductors and a 120°C design temperature along a new easement parallel to the original Line 86 (which is then removed)					
3	Rebuild Line 86 as a double circuit line	315.4	2027-28	280 MW	350 MW

** 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 (as relevant and subject to requested confidentiality) in the body of this PACR. ** The 'expected completion date' denotes the year after the replacement, or rebuild, work is undertaken and is akin to a 'commissioning year' for new lines. *** The expected transfer improvement due to reduced service outages reflects the transfer capacity loss under the base case if Line 86 fails (it has been coupled with the probability of failure, which increases each year going forward as the poles are left to deteriorate further, in the market modelling).*

This is the same set of credible options that was assessed in the PADR. However, as discussed above, Option 1C no longer includes an indicative second tranche of wood pole replacements because the assessment period for the PACR ends in 2040-41, before any further investment is expected to be required under Option 1C.

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.

Table E2: Summary of scenarios assessed in this PACR

Variable	Central	Low net economic benefits	High net economic benefits
Network capital costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Non-network costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Estimated risk costs	Base estimate	Base estimate - 25%	Base estimate + 25%
Wholesale market benefits estimated	EY estimated based on the step-change 2022 ISP scenario	EY estimated based on the progressive change 2022 ISP scenario	EY estimated based on the hydrogen superpower 2022 ISP scenario
Discount rate	5.50%	7.50%	2.30%

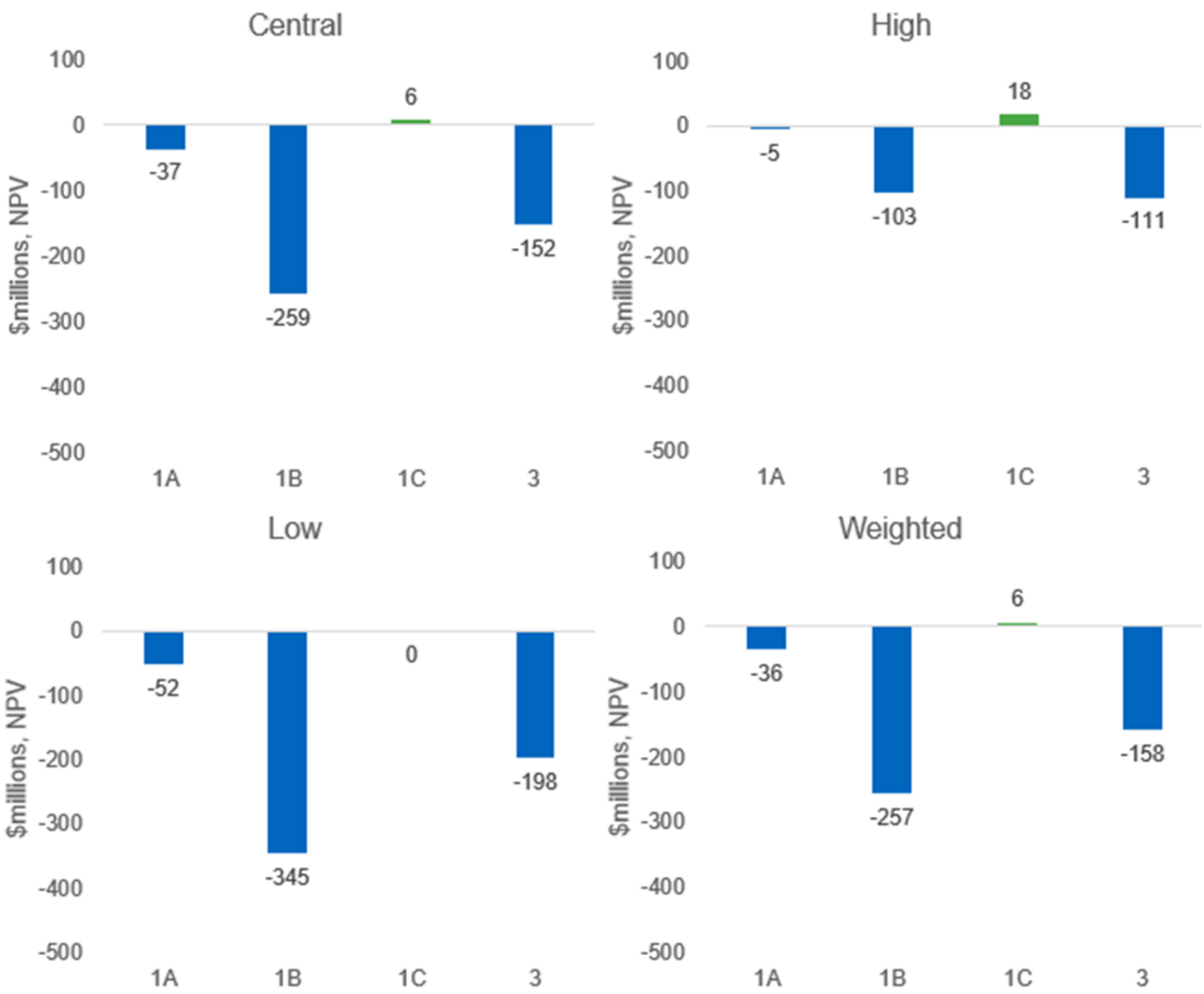
The wholesale market modelling in this PACR has been undertaken across the three key 2022 Integrated System Plan (ISP) scenarios. We have also weighted each of the scenarios for this RIT-T based on the 2022 ISP weightings for the underlying ISP scenarios, i.e.:

- 52 per cent to central scenario (based on the step-change scenario in the ISP);
- 30 per cent to the low benefits scenario (based on the progressive change scenario in the ISP); and
- 18 per cent to the high benefits scenario (based on the hydrogen superpower scenario in the ISP).

Option 1C is found to be the preferred option on a weighted basis and in the sensitivities investigated

The PACR finds that a focused replacement of the highest risk Line 86 poles, like for like in-situ with concrete or steel poles ('Option 1C') is the preferred option for meeting the identified need on a weighted basis and in the sensitivities assessed. Option 1C is expected to deliver approximately $6.2 million in net benefits over the 19-year assessment period (on a weighted-basis across the three scenarios), and approximately $5.7 million under the most likely scenario (the central scenario). Option 1C also delivers a positive benefit in the high scenario and is equivalent to the 'do nothing' base case in the low scenario, and is the highest ranked option in both cases.

Figure E-1: Estimated net benefits for each scenario



The vast majority of the estimated market benefits for the options in each scenario comes from their ability to avoid the risk costs identified.

The assessment finds that the cost of increasing the capacity of Line 86 to provide wider benefits to the wholesale market, either via network investment (Option 3) or a VTL (Option 1B), is not outweighed by additional expected benefits. This is the case in all scenarios investigated.

We have also tested the robustness of the conclusion that Option 1C is the preferred option to a range of sensitivities as part of this PACR – namely, for the most likely central scenario we have tested the impact of changes in:

- assumed level of risk costs;
- higher and lower network capital costs;
- higher and lower non-network capital costs; and
- alternate commercial discount rate assumptions.

Each sensitivity confirms Option 1C as the preferred option under this RIT-T.

We further find that there is no realistic increase in capital costs or commercial discount rate that would lead to Option 1C having a negative net benefit in the central scenario. Similarly, we find that there is no realistic decrease in the assumed level of risk costs that would result in Option 1C having negative net benefits in the central scenario.

Further information and next steps

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

Further details in relation to this project can be obtained from regulatory.consultation@transgrid.com.au. In the subject field, please reference 'Line 86 PACR.'

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Contents

1. Introduction

We have applied the Regulatory Investment Test for Transmission (RIT-T) to options for mitigating the risks we, and ultimately our downstream consumers, face as a consequence of the condition of the transmission poles that form part of one of the two key 330 kV transmission lines running between Tamworth and Armidale (Line 86). The condition of these wood poles gives rise to bushfire risk, and also results in higher expected costs associated with reactive maintenance (which may need to be done under emergency conditions).

Publication of this Project Assessment Conclusions Report (PACR) represents the final stage in the RIT-T process and follows the Project Assessment Draft Report (PADR) released on 30 May 2022. No submissions were received in relation to the PADR.

Line 86 is 111 km in length and was constructed in 1982 using mostly composite wood pole[4] structures. Specifically, there are 400 wood pole structures used in Line 86, representing 91 per cent of the total poles used.[5] Wood rot beneath the metal sleeve cylinder that holds the two wood pole sections together (referred to as a pole 'joint sleeve') is prevalent across the line and we have had to replace/remediate 10 per cent of the structures to-date.

While all of the credible options assessed in this PACR mitigate the risks associated with the condition of the wood poles, they also have the potential to impact the wider wholesale market in various ways, through increasing the network transfer capacity between Tamworth and Armidale. These expected wider wholesale market interactions are primarily due to the interaction with:

- the Queensland to New South Wales Interconnector (QNI), which is currently being upgraded; and
- the New England Renewable Energy Zone (REZ) around Armidale, which is being progressed under the NSW Government's Electricity Infrastructure Roadmap.

There was one structure failure on Line 86 in April 2020 due to wood rot deteriorating pole strength to below that required to withstand a strong wind event. While there were no customer interruptions due to the time of year the failure occurred (i.e., being outside of the peak summer period), it did limit the transfer capability across the QNI interconnector due to Line 86 being out of service while the pole was remediated. Specifically, Line 86 was out of service for a total of five days and the average import limit on QNI was reduced by approximately 822 MW, while the average export limit was reduced by approximately 264 MW.

1.1. Purpose

The purpose of this PACR is to:

- identify and confirm the market benefits expected from the various options for managing the risk on Line 86;
- outline the result of the PADR consultation process and developments since the PADR was released and highlight how these have been taken into account in the RIT-T analysis;
- describe the options 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;

4 A composite wood pole consists of a two-piece pole arrangement that is held together by a metal cylinder/sleeve.
5 A short section (3.72km) of the line outside Tamworth is constructed on steel towers.

- 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 under 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 a supplementary market modelling report on our website to complement this PACR. Detailed cost benefit results are included as a spreadsheet appendix accompanying this report.

1.2. Further information and next steps

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

Further details in relation to this project can be obtained from regulatory.consultation@transgrid.com.au. In the subject field, please reference 'Line 86 PACR.'

2. Benefits from addressing the condition of the Line 86 wood poles

This section outlines the key benefits expected from the options assessed for addressing the condition of the Line 86 wood poles. It first summarises the developments that have occurred since the PADR was released and how they have been reflected in this PACR. It then outlines the two key sources of benefits expected from addressing the condition of the Line 86 wood poles before re-summarising the identified need for this RIT-T.

2.1. Developments since the PADR

There have been three key developments since the PADR was released that have affected the analysis of wholesale market benefits in the PACR – namely:

- the final 2022 ISP was published 30 June 2022;
- AEMO released its latest database of committed and anticipated generation projects in the NEM in June 2022; and
- Transgrid and ElectraNet have updated the date that full capacity is expected to be available from EnergyConnect following the completion of inter-regional testing to 1 July 2026.[6]

Each of these have been reflected in the wholesale market modelling presented in this PACR. Specifically, the inputs and assumptions in the PACR wholesale market modelling fully align with the final 2022 ISP, with the exception of the database of committed and anticipated generation projects and the assumed timing of EnergyConnect (both of which reflect the latest information available and were not able to be reflected in the final 2022 ISP).

We have also further considered the appropriate assessment period for this RIT-T, as flagged in the PADR, in light of the expected timing and uncertainty around later stages of investment. In particular, in the PADR the analysis of Option 1C included an indicative second set of pole replacements that is not expected to be required until after 2040 (and would again only focus on the highest risk poles at that time). Given how far into the future this investment is expected to occur, and its indicative nature at this stage, we have taken the approach of truncating the assessment period for the PACR so that it ends in 2040-41 (i.e., before any further investment is expected to be required). Any future program of investment to replace further poles on Line 86 would be subject to a subsequent RIT-T closer to the time.

We note that shortening the assessment period from 27 years to 19 years has the effect of reducing the net benefits of the options because:

- substantial avoided risk cost benefits after 2040-41 are no longer captured in the analysis; and
- any further capital expenditure included towards to the end of the assessment period would have a high terminal value, and so has little impact on the present value of costs in the analysis.

We therefore consider that the 19-year assessment period adopted for the PACR represents a conservative assumption of the net market benefits of the options.

6 AEMO, *2022 Integrated System Plan*, June 2022, p. 66, Table 5.

2.2. Avoiding an unacceptable level of risk due to pole condition issues

Line 86 is a 330 kV single-circuit line, running between Tamworth and Armidale (111 km), and was constructed in 1982 using mostly composite wood pole[7] structures.[8]

Line 86 is the only 330 kV line in our network that was not constructed using steel towers. Due to its composite wood pole construction, Line 86 was designed and constructed to a lower set of criteria more comparable to other lower capacity Transgrid wood pole lines rather than the criteria applied to 330 kV steel towers. Its construction utilises shorter span lengths and a smaller lighter weight twin 'lime' ACSR conductor (compared to typical 'mango'/'olive' conductors used on other Transgrid 330 kV lines),[9] which reduces the rating of the line.

Wood rot beneath the composite pole joint sleeve is prevalent throughout the composite wood poles that are utilised along the line. We have replaced, or remediated, 40 poles since 2000, which represents 10 per cent of the original wood poles on Line 86.

Figure 2-1 shows an example of wood rot on one of the poles that required replacing.

Figure 2-1: Example of wood rot on Line 86

We undertake frequent monitoring and condition reporting on Line 86, which has consistently identified issues with wood decay beneath the composite pole joint sleeves. For example, in 2011, twenty two structures were identified to be defective and required replacement due to condition related issues. Further, in the past two years, an additional four defective poles have had to be replaced and, over the course of 2021, we identified a further ten wood pole structures that require replacement due to the condition issues.

Defective wood poles are ideally identified and replaced before they fail structurally. However, sometimes poles fail before defects are able to be identified and/or the poles replaced. For example, in April 2020, we had a pole forming part of Line 86 structurally fail due to wood rot deteriorating pole strength to below that required to withstand a strong wind event. While there were no customer interruptions due to the time of year the failure occurred (i.e., being outside of the peak summer period), it did limit the transfer capability across the QNI interconnector due to Line 86 being out of service while the pole was remediated. Line 86

7 A composite wood pole consists of a two-piece pole arrangement that is held together by a metal cylinder/sleeve.

8 A short section (3.72km) of the line outside Tamworth is constructed on steel towers.

9 A 'lime' conductor has strand sized at 30 / 7/ 3.5mm. This compares to 'mango' conductors that have strand sized at 54 /7/3.00mm and 'olive' conductors that have strand sized at 54 /7/3.50mm. The stranding gives the number and diameter of aluminium and steel strands, e.g. lime 30 / 7/ 3.5mm means 30 strands of aluminium and 7 strands of steel, all 3.5mm in diameter.

was out of service for a total of five days and the average import limit on QNI was reduced by approximately 822 MW, while the average export limit was reduced by approximately 264 MW.

If action is not taken, the condition of the wood poles is expected to expose Transgrid and its customers to unacceptable levels of risk going forward. Specifically, and as set-out in section 6.2, there are significant bushfire risks under the base case, as well as higher expected costs associated with reactive maintenance that may be required under emergency conditions ('financial risks'). There are also expected to be reputational, safety and reliability risks if the condition of the poles is not addressed but these are small relative to the bushfire and financial risks estimated.

The condition of the wood poles on Line 86 was raised as part of the NSW Government's 2020 Bushfire Inquiry. Specifically, the Inquiry heard that the capacity of the QNI interconnector relies in part on wood power poles and the Inquiry's Final Report stated that "the QNI is a vital asset and should be made more resilient through the replacement of the timber poles with suitable alternatives that are more fire resistant."[10] This statement reinforces the identified need for this RIT-T.

2.3. Potential to provide wider wholesale market impacts due to the location of Line 86

Figure 2-2 illustrates the location of Line 86 in our Northern NSW transmission network, i.e., running between Armidale and Tamworth.

Figure 2-2: Northern NSW transmission network

10 Final Report of the NSW Bushfire Inquiry, 31 July 2020, p. 327 – available at: https://www.dpc.nsw.gov.au/assets/dpc-nsw-gov-au/publications/NSW-Bushfire-Inquiry-1630/Final-Report-of-the-NSW-Bushfire-Inquiry.pdf.

Line 86 is a critical transmission line in the evolving National Electricity Market (NEM) and there are expected to be wider wholesale market impacts from both lower outages on Line 86 (due to replacing the deteriorating poles) as well as from any expansion in its transfer capacity, given future wholesale market developments. Specifically:

- with Liddell Power Station, shown at the bottom of Figure 2-2, retiring in April 2023, Line 86 will transfer more power from Queensland and Northern NSW to supply major load centres in NSW (and elsewhere in the NEM);
- the New England REZ, shown in light blue in Figure 2-2, is to be developed in the area surrounding Armidale as part of the NSW Government's Electricity Strategy and Electricity Infrastructure Roadmap and is planned to support the development of up to 8,000 MW of renewable generation capacity,[11] which will rely in part on Line 86 to transmit this electricity to the wider NEM; and
- following the completion of the QNI minor upgrade (a committed transmission project), in mid-2023,[12] the lines between Tamworth and Armidale will be the main constraint in the sharing of capacity between NSW and Queensland. In the event of a failure of Line 86, significant operating constraints will need to be applied on QNI to manage the next credible contingency (the trip of the remaining Armidale-Tamworth line) that would otherwise result in separation of Queensland and Northern NSW from the rest of the NEM.

The notional transfer capacity increases that Transgrid has determined for each of the options assessed in this PACR are a result of our modelling of the thermal limitations under each option, as well as the future limitations expected in the base case if no action is taken.

As stated in the PADR, at the time of the PSCR, we expected that increasing the transfer capacity of Line 86 by rebuilding it with a larger capacity line (or coupling it with a VTL) would result in significant wholesale market benefits due to the above interactions. This expectation was supported by preliminary, internal analysis using the 2020 ISP assumptions.

This PACR (as well as the PADR) includes a comprehensive wholesale market modelling exercise undertaken by EY that draws on the assumptions used in the Final 2022 ISP. The 2022 ISP includes a range of updated assumptions since the 2020 ISP that have affected the wholesale market benefits associated with increasing the transfer capacity of Line 86. In particular, the 2022 ISP contains updated assumptions in relation to the New England REZ and its associated transmission connection.

The wholesale market modelling undertaken as part of this PACR (and the PADR) has found that rebuilding Line 86 as a higher capacity line actually results in significant negative wholesale market benefits (i.e., a cost relative to the base case). This was not expected prior to the PADR assessment and has been found to be due to the larger capacity line reducing the impedance on the existing 330 kV flow-path from Armidale to Tamworth to Liddell, which increases the proportion of flow across that path rather than the assumed 500 kV route from Armidale to Tamworth to Baywater as part of the New England REZ augmentation. This causes the 330 kV lines from Tamworth to Liddell to bind sooner, which results in lower transfer limits between northern NSW and central NSW than under the base case and so a wholesale market *cost* for this option. Since NSW demand cannot be met as easily from generation in northern NSW or Queensland in light of the lower transfer limits, more generation capacity is forecast to be built in central NSW than under the base case (which is the primary driver of the market cost).

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[11] https://www.energy.nsw.gov.au/renewables/renewable-energy-zones
[12] AEMO, *2022 Integrated System Plan,* June 2022, p. 66.

2.4. Description of the ‘identified need’

Given the increasing rate of defect issues, including required pole replacements, and past experience with composite wood pole structures, we consider it is likely that all the structures on Line 86 are exhibiting various forms of decay, which is only expected to worsen over time. The deteriorating condition of the wood poles gives rise to bushfire risk and also results in higher expected costs associated with reactive maintenance (which may need to be done under emergency conditions). The benefit expected from avoiding these risks proactively (i.e., ahead of when they fail) is expected to exceed the replacement costs for the preferred option.

In addressing the condition issues on Line 86, we have also investigated whether an opportunity exists to provide extra capacity in this region of our network, and in doing so address the potential for future constraints in the network and facilitate conditions that enable greater access to market benefits associated with new generation and storage within the NEM.

This RIT-T therefore assesses options to address the asset condition issues identified on Line 86, while providing the greatest overall net benefit to the market over the long-term.

We consider this a ‘market benefits’ driven RIT-T, as opposed to a ‘reliability corrective action’, and expect the ultimately preferred option to have positive expected net market benefits (as is shown in the NPV assessment presented in this PACR).

3. Consultation on the PADR

The PADR was released in May 2022, with written submissions requested by 15 July 2022.

No submissions were received in relation to the PADR.

4. Credible options assessed

The credible options in this RIT-T assessment are those that meet the identified need from a technical, commercial, and project delivery perspective.[13] This includes options put forward by proponents in response to the earlier PSCR.

We have identified and assessed four options that we consider meet the identified need for this RIT-T, as summarised in Table 4-1 below.

Table 4-1: Summary of the credible options

Option	Description	Estimated capital cost ($2021-22)	Expected completion date*	Expected transfer improvement (reduced service outages)**	Expected transfer improvement (higher rating)
Replace Line 86 like for like in-situ utilising concrete or steel poles, keeping the existing twin lime conductor and single circuit configuration, while maintaining the overall design temperature at 100°C					
1A	Replace all (367) poles in one-go	95.7	2027-28	280 MW	-
1B	Replace all (367) poles in one-go and couple with a VTL (2 x 200 MW batteries)	95.7 (for the line) Confidential for the VTL	2027-28 (for the line) 2023-24 (for the VTL)	280 MW	200 MW (from the VTL)
1C	Replace the highest risk structures (31) over 2025-26 to 2027-28; with the remaining structures (336) replaced beyond the assessment period	10.65 (2025-26 to 2027-28)	2028-29	280 MW	-
Rebuild Line 86 as a double circuit with twin olive conductors and a 120°C design temperature along a new easement parallel to the original Line 86 (which is then removed)					
3	Rebuild Line 86 as a double circuit line	315.4	2027-28	280 MW	350 MW

** The 'expected completion date' denotes the year after the replacement, or rebuild, work is undertaken and is akin to a 'commissioning year' for new lines. ** The expected transfer improvement due to reduced service outages reflects the transfer capacity loss under the base case if Line 86 fails. It has been coupled with the probability of failure, which increases each year going forward as the poles are left to deteriorate further, in the market modelling.*

In relation to Option 1C, there has been an update to the option since the PADR. We have further considered the appropriate assessment period for this RIT-T, as flagged in the PADR, in light of the expected timing and uncertainty around later stages of investment for Option 1C. In particular, in the PADR the analysis of Option 1C included an indicative second set of pole replacements that is not expected to be required until after 2040. Given how far into the future this investment is expected to occur, and its

[13] As per clause 5.15.2(a) of the NER.

indicative nature at this stage, we have taken the approach of truncating the assessment period for the PACR so that it ends in 2040-41 (i.e., before any further investment is expected to be required). Any future program of investment to replace further poles on Line 86 would be subject to a subsequent RIT-T closer to the time.

The assessment in the PADR (which adopted a longer assessment period and which did include this indicative second tranche of investment), found that Option 1C was the preferred option, and so we do not consider the change in this assumption material to the outcome of this RIT-T. Further, as discussed in section 6.4, shortening the assessment period represents a conservative assumption because it has the effect of reducing the net benefits of the Option 1C due to lower avoided risk cost benefits.

Table 4-2 provides a further breakdown of the categories of capital cost estimated for each of the credible options.

Table 4-2: Breakdown of the estimated capital costs of the credible options, $m 2021-22

Option	Lines	Substations	Land	Batteries	Total
1A	95.7	-	-	-	95.7
1B	95.7	-	-	Confidential	Confidential
1C	10.65	-	-	-	10.65
3	251.6	-	63.8 (includes 39.96 for biodiversity offsets)	-	315.4

We note that Option 1A, Option 1B and Option 1C only replace the poles on Line 86 and do not replace the actual line ('conductor'). Our current view is that the existing conductor will need to be replaced under these options in 30-40 years' time and so has not been included in the NPV assessment.[14]

4.1. Option 1A – Replace Line 86 wood poles like for like in-situ with concrete or steel poles by the end of 2026-27

Option 1A involves replacing Line 86 wood poles like for like in-situ with concrete or steel poles, keeping the existing twin lime conductor and single circuit configuration. The scope of this option does not involve replacing the existing concrete poles and maintains the overall design temperature at 100°C.

It is expected that the works will be undertaken in various stages between 2023-24 and 2026-27, with the actual targeted replacement work occurring in the last two years of this period (the first two years are primarily planning and procurement). All work is expected to be completed by the end of 2026-27.

Option 1A provides an increase in transfer capacity between Armidale and Tamworth of approximately 280 MW, relative to the base case, when it is assumed that there is the possibility that the line may be out of service due to pole failure. However, it does not result in any increase in actual line capacity, compared to

[14] Specifically, we have not included the replacement of the existing conductor under Option 1A, 1B or 1C in the analysis on account of how far into the future it is expected to be required, as well as its relatively low expected cost (currently estimated at $27 million). Moreover, a conductor of this type typically has a life of 90 years.

when the existing line is in-service under the base case, i.e., it maintains the same operating capacity as the current line.

Given the existing line is already in service, outages will be planned as necessary in order to complete the works. Outages are assumed to occur over three, three month periods each year (i.e., nine months in total) in order to minimise the impact on the wholesale market. The impact of these planned outages on the wholesale market has been captured for Option 1A in the PACR market modelling.

The estimated capital cost of this option is approximately $95.7 million. Routine operating and maintenance costs are expected to be approximately $80,000/annum (around 0.08 per cent of the capital expenditure), which compares to approximately $293,000/annum under the base case (where more frequent inspections are required due to the deteriorating wood pole condition).

4.2. Option 1B – Coupling a VTL with Option 1A

Option 1B involves coupling Option 1A with a VTL. Specifically, Option 1B involves exactly the same scope, timing and outage profile as Option 1A in term of replacing the poles on Line 86 as well as 200 MW batteries at each of Armidale and Liddell operating as a VTL.

In addition to the 280 MW increase in transfer capacity between Armidale and Tamworth provided by Option 1A, relative to the base case in the event that the existing wood poles fail, Option 1B also increases transfer capacity at all times in this region of our network by 200 MW due to the VTL component.

The estimated costs of the VTL component have been kept confidential in this PACR, as requested by the proponent.

4.3. Option 1C – Replacement of highest risk Line 86 wood poles like for like in-situ with concrete or steel poles in 2027-28

Option 1C involves replacing the 31 highest risk[15] Line 86 wood poles between 2025-26 and 2027-28 like for like in-situ with concrete or steel poles, keeping the existing twin lime conductor and single circuit configuration. As with Option 1A, the scope of this option does not involve replacing the existing concrete poles and maintains the overall design temperature at 100°C.

We note that the replacement of the remaining poles on Line 86 would be subject to a separate RIT-T in the future to determine whether this work is justified (and in what form).

In the PADR the analysis of Option 1C included an indicative second set of pole replacements that is not expected to be required until after 2040 (and would again only focus on the highest risk poles at that time). We have further considered the appropriate assessment period for this RIT-T, in light of the expected timing and uncertainty around later stages of investment. Given how far into the future the second tranche of pole replacements is expected to occur, and its indicative nature at this stage, we have taken the approach of truncating the assessment period for the PACR so that it ends in 2040-41 (i.e., before any further investment is expected to be required). As discussed in section 6.4, shortening the assessment period represents a conservative assumption because it has the effect of reducing the net benefits of the Option 1C due to lower avoided risk cost benefits.

15 When we refer to 'highest risk' in this PACR, we are referring to the poles that have been determined to present the greatest risk, which is based on an assessment of both the condition of individual poles and the risk that they pose, e.g., taking into account the likelihood and consequence(s) of failure.

Option 1C, which is a smaller scale option than those originally put forward in the PSCR, was included in the PADR investigation following the findings that:

- the larger capacity options (e.g., Option 2 and Option 3 from the PSCR) are not expected to provide gross wholesale market benefits; and
- the avoided risk costs associated with replacing all poles in one-go (i.e., Option 1A) does not justify the cost of doing so.

The 31 poles included for replacement between 2025-26 and 2027-28 were identified through a process of reviewing the updated data on both the condition and risk of each of the 400 poles on Line 86 and comparing the expected risk reduction from replacing each pole with the associated cost. Specifically, this process involved an assessment of both the condition of individual poles and the risk that they pose, e.g., taking into account the likelihood and consequence(s) of failure. We consider that replacing the 31 poles maximises the expected aggregate risk reduction relative to replacement cost in the immediate term.

Like Option 1A, Option 1C does not result in any increase in actual line capacity, compared to when the existing line is in-service under the base case, i.e., it maintains the same operating capacity as the current line.

Outages are estimated to take one month (March 2028). The impact of these planned outages on the wholesale market has been captured for Option 1C in the PACR market modelling.

The estimated capital cost of this option is approximately $10.65 million. We note that the replacement cost per pole is higher under Option 1C than Option 1A due to the efficiencies associated with replacing all poles in one-go (Option 1A), compared to a piecemeal replacement (Option 1C), e.g., contractor establishment, mobilisation and management costs.

Routine operating and maintenance costs are expected to fall to approximately $271,000/annum after replacing the 31 highest risk Line 86 poles, compared to $293,00/annum in the base case.

4.4. Option 3 – Rebuild Line 86 as a double circuit line (strung on both sides)

Option 3 involves rebuilding Line 86 as a double circuit line with both sides strung initially using twin olive conductors and a 120°C design temperature.

Option 3 is expected to provide an increase in transfer capacity between Armidale and Tamworth of approximately 630 MW, relative to the base case, through both avoiding the expected periods of line outage in the event that the existing wood poles fail (i.e., consistent with Option 1A) and also through providing an additional circuit in this part of the network.

It is expected that the works will be undertaken between 2023-24 and 2026-27, with ultimate commissioning of the new line in 2027-28. Once the new line is commissioned the existing line will be removed and the cost of this has been included in the cost for Option 3.

Option 3 is estimated to involve one week of planned outage in June 2027. The impact of this planned outage on the wholesale market has been included in the PACR market modelling.

The estimated capital cost of this option is approximately $315.4 million, including the additional easement cost and biodiversity offset costs. Routine operating and maintenance costs are expected to be approximately $92,000/annum (around 0.03 per cent of the capital expenditure), which compares to $293,000/annum under the base case (where more frequent inspections are required).

4.5. Options considered but not progressed

We have also considered whether other options could meet the identified need over the course of this RIT-T. The reasons these options were not progressed are summarised in Table 4-3.

Table 4-3: Options considered but not progressed

Option	Reason(s) for not progressing
Rebuild Line 86 as a double circuit line (initially strung on one side only) – 'Option 2' from the PSCR	This option was determined not to be commercially feasible in light of the wholesale market modelling undertaken as part of the PADR. The updated market modelling in the PACR, with the same pattern of estimated market benefits as the PADR, does not change this conclusion. This option was designed to be a 'flexible' option that rebuilt the line to be able to be operated as a double-circuit line but initially only strung on one side, i.e., effectively initially operating as Option 1A until being upgraded to Option 3. As outlined in the PADR (and this PACR), the wholesale market modelling finds that both Option 1A and Option 3 have significantly negative net market benefits due to the pattern of outages relative to the base case (for Option 1A) and the additional costs (for Option 3), meaning that Option 2 from the PSCR is also expected to have significantly negative net market benefits and so has not been assessed further. Moreover, the market modelling results for Option 3 mean that Option 2 is now never expected to be upgraded from being strung on one side to being strung on both sides and so essentially represents a significantly more expensive version of Option 1A (with the same expected market benefits).
Coupling a VTL with Option 1C	We have not investigated coupling a VTL with Option 1C since the additional cost of the VTL is found to not be outweighed by the additional expected wholesale market benefits under the assessment of Option 1B (where the VTL is coupled with Option 1A). This will not change if the VTL is coupled with Option 1C and so this combination is not considered commercially feasible and has not been progressed.
Use of an alternate conductor technology	In response to the PSCR, a party proposed the use of an alternate conductor technology for Option 2 and Option 3. The use of this technology has been assessed but not progressed as part of the PADR or PACR since these two network options are found to either not be commercially feasible (Option 2), or have costs that far outweigh the benefits (Option 3), and any cost reductions due to the alternate conductor technology are not expected to change these findings. Furthermore, the variants of Option 1 do not include replacement of the existing conductor in the analysis period, and therefore combining an Option 1 variant with replacement of the existing conductor with an alternate technology is not considered commercially feasible and has not been progressed.

Option	Reason(s) for not progressing
Further uprating the existing line (e.g., by installing taller poles)	Not commercially feasible. Line 86 is constructed with a twin lime ACSR conductor with an original design temperature of 85°C. It has since been upgraded to a design temperature of 100°C. While the option to uprate the line to a design temperature of 120°C has been considered, it results in only a negligible contingency rating increase and is not expected to provide incremental benefits that are commensurate with the increase in cost associated with the uprating.
Rebuild Line 86 as single circuit with twin mango conductors and a 120°C design temperature parallel to the original Line 86 (which is then removed) on a new easement	Not commercially feasible. This option has been considered but not progressed since it costs significantly more than Option 1A ($192.7 million, compared to $95.7 million) and is expected to provide essentially the same benefits in terms of both avoided risk costs and through its increase in transfer capacity compared to the base case. While this option would avoid an extended period of outage during construction, relative to Option 1A, since the new line is built on a separate easement, the impact of this is not expected to be commensurate with the cost difference between these two options.

5. Ensuring the robustness of the analysis

The 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 also identified the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for these factors, beyond which the outcome of the analysis would change.

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 (including the expected impact on the wholesale market).

The three alternative scenarios are characterised as follows:

- a 'low net economic benefits' scenario, involving a number of assumptions that gives a lower bound and conservative estimate of net present value of net economic benefits;
- a 'central' scenario which consists of assumptions that reflect our central set of variable estimates that provides the most likely scenario; and
- a 'high net economic benefits' scenario that reflects a set of assumptions which have been selected to investigate an upper bound of net economic benefits.

The table below summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered.

Table 5-1: Summary of scenarios

Variable	Central	Low net economic benefits	High net economic benefits
Network capital costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Non-network costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Estimated risk costs	Base estimate	Base estimate - 25%	Base estimate + 25%
Wholesale market benefits estimated	EY estimated based on the step-change 2022 ISP scenario	EY estimated based on the progressive change 2022 ISP scenario	EY estimated based on the hydrogen superpower 2022 ISP scenario
Discount rate	5.50%	7.50%	2.30%

While wholesale market benefits (and so the ISP scenarios) are relevant to this RIT-T, we note that they are only one element that is expected to affect the ranking of the credible options. The scenarios developed for this RIT-T therefore include the three 2022 ISP scenarios, as well as the following variables that are expected to affect the ranking of the options:

- network and non-network capital costs – given the cost differences between the options, the underlying drivers of capital costs are expected to have a bearing on which option is ultimately preferred, and a 25 per cent higher and lower range is consistent with the level of accuracy in the estimates provided;
- estimated risk costs – these estimates are subject to uncertainty, and avoided risk costs are a key source of benefit for each of the options, and so we have reflected risk costs estimates that are 25 per cent higher and lower across the scenarios; and
- discount rate – the discount rate directly affects the trade-off between costs now and benefits in the future and we have reflected three different discount rates in the scenarios

The three scenarios assessed in this PACR reflect combinations of the above assumptions, as well as wholesale market benefits estimated for each of the three 2022 ISP scenarios. We consider that this approach allows for a more robust test of the preferred option compared with adopting individual sensitivity tests, since multiple variables are changed at once.

We engaged EY to undertake the wholesale market modelling to assess the market benefits/costs associated with how each of the credible options are expected to have an impact on the wholesale market. As outlined in section 2.1, the wholesale market modelling has been updated since the PADR to align with the final 2022 ISP as well as additional information regarding generator developments and the timing of EnergyConnect.

As shown above, EY have modelled the wholesale market benefits of each of the options across each of the following three 2022 ISP scenarios:

- step-change (for the 'central' scenario above);
- progressive change (for the 'low benefits' scenario above); and
- hydrogen superpower (for the 'high benefits' scenario above).

The slow-change scenario from the 2022 ISP scenarios has not been modelled given the low likelihood ascribed to this scenario in the 2022 ISP (i.e., the 4 per cent weighting AEMO gave this scenario).[16]

The ISP scenarios reflect different assumptions regarding key drivers of the wholesale market benefits, including demand, future carbon policies and the uptake of renewable generation (including for the New England REZ). The ISP also sets out the 'optimal development path' for the timing and size of other transmission developments in the NEM (e.g., the QNI minor upgrade scheduled for mid-2023).[17]

We have weighted each of the scenarios based on the 2022 ISP weightings. Specifically, we have given each scenario a weighting based on the proportion its weighting in the 2022 ISP makes up of the cumulative 96 per cent given to these three scenarios, i.e.:[18]

- 52 per cent to the step-change;
- 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 7.4), we have also carefully considered the results in each scenario in section 7.

5.2. Sensitivity analysis

As outlined above, the three 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, which varies one variable at a time to test the robustness of the preferred option to alternate assumptions regarding that variable alone (in relation to the most likely, central scenario).

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

- assumed level of risk costs;
- higher and lower network capital costs;
- higher and lower non-network capital costs; 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 'threshold value' for key variables beyond which the outcome of the analysis would change.

16 AEMO, *2022 Integrated System Plan*, June 2022, p. 34.
17 Table B-1 in Appendix B summarises the key variables in each ISP scenario that influence the net benefits of the options.
18 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 2022 ISP released in June 2022 – see: AEMO, *2022 Integrated System Plan*, June 2022, p. 75.

6. Estimating the benefits of the credible options

As outlined in section 2, the credible options are expected to provide significant benefits through avoided risk costs (from replacing the Line 86 wood poles) as well as impact the wider wholesale market in varying capacities relative to the base case.

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:

- inherent risks and their expected costs (i.e., the 'risk costs'); and
- NEM outcomes expected, 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 benefit have been estimated. It first outlines the 'base case' for assessment.

EY has undertaken the wholesale market modelling component of the PACR assessment. Appendix B provides additional detail on the wholesale market modelling undertaken by EY. EY have published 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. Base case

Consistent with the RIT-T requirements, the assessment undertaken in the PACR compares the costs and benefits of each option to a base case 'do nothing' option. The base case is the (hypothetical) projected case if no action is taken, i.e.:[19]

> *"The base case is where the RIT-T proponent does not implement a credible option to meet the identified need, but rather continues its 'BAU activities'. 'BAU activities' are ongoing, economically prudent activities that occur in absence of a credible option being implemented"*

Under the base case, where the affected poles are not replaced, there is expected to be significant risk to our network and customers. In particular, we consider the base case to involve material risk costs and, in particular, bushfire and financial risks.

In addition, the base case will also result in a reduction in the transfer limit between Armidale and Tamworth, and hence the QNI interconnector, during periods of outage on Line 86.

While the base case is not a situation we plan to encounter, and this RIT-T has been initiated specifically to avoid it, the assessment is required under the RIT-T to use this base case as a common point of reference when estimating the net benefits of each credible option.

The base case for the PACR assessment includes the replacement of the wood pole structures identified over the course of inspections in 2021 in estimating risk costs (since these assets have failed our inspection/serviceability tests and require reactive replacement).

[19] AER, *Regulatory Investment Test for Transmission Application Guidelines,* August 2020, p. 21.

6.2. Avoided risk cost benefits

Key sources of benefit for this RIT-T relate to avoiding the estimated risk cost associated with the deterioration in the condition of the composite wood poles utilised for Line 86. This section describes the assumptions underpinning our assessment of the base case risk costs, i.e., the value of the risk avoided by undertaking the credible options.

We have a robust model for quantifying risk costs in our network, which has recently been subject to a thorough review and enhancement (including with respect to asset health and the probability of failure[20]).

While the sections below focus on the three primary sources of risk for this RIT-T (i.e., bushfire risk, financial risk and reputational risk), our risk cost modelling also captures safety and reliability risks. However, these two sources of risk are substantially lower than the other categories for this RIT-T (making up less than 1 per cent of the total estimated risk cost together for this RIT-T) and so have not been covered here (but have been included in the NPV assessment).[21]

6.2.1. Bushfire risk

This risk refers to the consequence to the community of an asset failure that results in a bushfire starting. We undertook an assessment with the University of Melbourne over December 2020 to improve our quantification of bushfire risks across our network, including the moderation of risk costs.

Our model uses an electricity industry-developed approach to increase consistency with other electricity networks. The model:

- estimates the potential spread from a fire started by each asset in the network, using recognised fire modelling software;
- calculates the consequence based on the number of houses, agricultural and forestry land use (and other infrastructure in the predicted burn area); and
- moderates the consequence using a statistical distribution of fire conditions across the year to come up with a most likely consequence to be used in the investment decision.

Bushfire risk is the largest of all risks quantified under the base case for this RIT-T, making up approximately 74 per cent of the total estimated risk cost.

6.2.2. Financial risk

This risk refers to the direct financial consequence arising from the failure of an asset, including the cost of replacement or repair of the asset which may need to be under emergency conditions. The estimated risk cost includes estimates of litigation costs, investigation costs and legislation breaches.

Financial risk is the second largest of all risks quantified under the base case for this RIT-T, making up 23 per cent of the total estimated risk cost.

6.2.3. Reputational risk

This risk refers to the direct financial consequence associated with the cost of liaison and engagement with media, the community and other stakeholders arising from the failure of an asset. Reputational risk has

[20] See section 2.3.6 of the PSCR for a description of how our risk cost estimation methodology considers asset health and the probability of failure.
[21] A description of these two categories of risk can be found in sections 2.3.4 and 2.3.5 of the PSCR, respectively.

been quantified as a much lower order of magnitude under the base case for this RIT-T, making up only 3 per cent of the total estimated risk cost.

6.3. Expected wholesale market benefits

The options considered are also expected to affect outcomes in the wholesale market, relative to the base case, particularly for those options which increase the operating capacity of the current Line 86.

The following categories of wholesale market benefit under the RIT-T have been modelled as part of this PACR:

- changes in costs for parties other than the RIT-T proponent (ie, 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 the market benefits is discussed in greater detail in the accompanying market modelling report prepared by EY.

6.4. General modelling parameters adopted

The analysis in this PACR spans a 19-year assessment period, from 2022-23 to 2040-41. This is shorter than the 27-year period, from 2021-22 to 2047-48, adopted for the PADR analysis.

As noted in section 4.3, we have further considered the appropriate assessment period for this RIT-T, as flagged in the PADR, in light of the expected timing and uncertainty around later stages of investment. In particular, in the PADR the analysis of Option 1C included an indicative second set of pole replacements that is not expected to be required until after 2040 (and would again only focus on the highest risk poles at that time). Given how far into the future this investment is expected to occur, and its indicative nature at this stage, we have taken the approach of truncating the assessment period for the PACR so that it ends in 2040-41 (i.e., before any further investment is expected to be required). Any future program of investment to replace further poles on Line 86 would be subject to a subsequent RIT-T closer to the time.

We consider that the assessment period adopted continues to take into account the size, complexity and expected lives of the options and provides a reasonable indication of the costs and benefits over a long outlook period. We note that shortening the assessment period from 27 years to 19 years has the effect of reducing the net benefits of the options because:

- substantial avoided risk cost benefits after 2040-41 are no longer captured in the analysis; and
- any further capital expenditure included towards to the end of the assessment period would have a high terminal value, and so has little impact on the present value of costs in the analysis.

We therefore consider that the 19-year assessment period adopted for the PACR represents a conservative assumption of the net market benefits of the options.

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

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 PACR, 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 2.30 per cent,[22] and an upper bound discount rate of 7.50 per cent (i.e., the upper bound used for the 2022 ISP[23]).

6.5. 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.[24]

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. None of the credible options assessed in this PACR have the requisite flexibility for option value. While Option 2 from the PSCR exhibited this flexibility, it has consequently been found to not be commercially feasible (as outlined in section 4.5) and so has not been assessed in this PACR.

As explained in the PADR, we no longer consider competition benefits to be potentially material for this RIT-T in light of the wholesale market modelling undertaken. Specifically, in light of findings of the PADR, we do not expect competition benefits to add sufficient gross wholesale market benefits to Option 1B (the only option with positive gross wholesale market benefits) in order to bridge the gap with Option 1C. These findings are supported by the results of the PACR analysis. In addition, we expect that the inclusion of competition benefits would further add to the net costs of Option 1A and Option 3 since they have both been found to have gross wholesale market costs.

Changes in ancillary service costs are also not considered likely to be material, which was flagged in the PSCR and received no submissions.

While the cost of Frequency Control Ancillary Services (FCAS) may change as a result of changed generation dispatch patterns and changed generation development following any increase to transfer capacity from the options, we consider that changes in FCAS costs are not likely to be materially different between options and are not expected to be material in the selection of the preferred option. FCAS costs are relatively small compared to total market costs.

[22] 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/powerlink-determination-2022%E2%80%9327/final-decision.

[23] AEMO, *2021 Inputs, Assumptions and Scenarios Report*, July 2021, p. 105; and AEMO, *2022 Integrated System Plan*, June 2022, p. 91.

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

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

7. Net present value results

This section outlines the results of the assessment we have undertaken of the credible options for this RIT-T.

Due to the confidentiality requested by proponents of solutions, we are only able to present the overall net market benefits for Option 1B (i.e., the present value of the aggregate market benefits estimated less the present value of the aggregate costs).

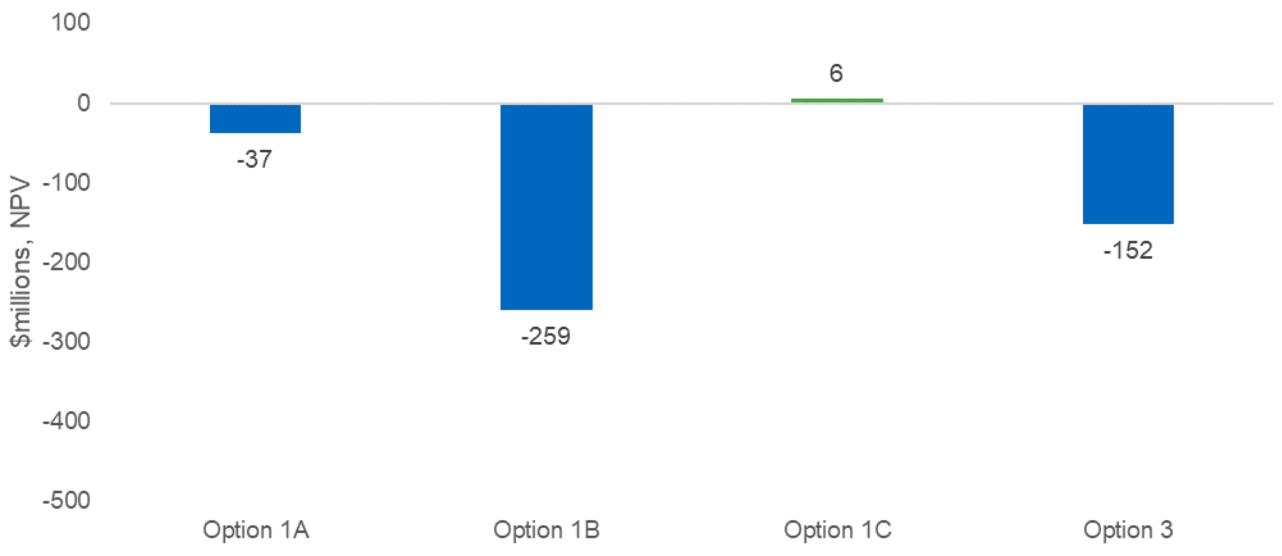
7.1. Central scenario

The central scenario reflects our central view of key underlying assumptions and is considered the most likely scenario in terms of the net market benefits for each of the options. These assumptions include central cost estimates, central risk costs estimates and commercial discount rate estimates. This scenario also includes EY's market modelling of the wholesale market benefits under the 2022 ISP step-change scenario.

Under these assumptions, Option 1C is found to be the top-ranked option and to deliver approximately $5.7 million in net benefits. Option 1C is the only option delivering positive net benefits under the central scenario, with the next best option (Option 1A) delivering net costs of $37.0 million and so being ranked below the option of taking no action (i.e., the 'do nothing' base case).

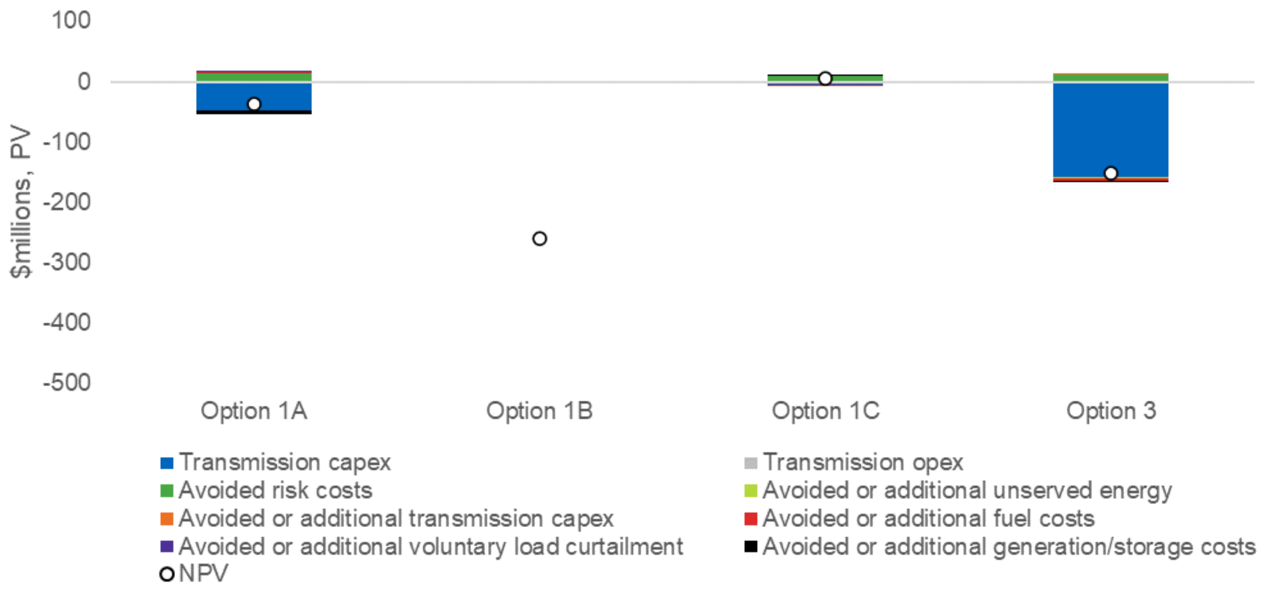
Figure 7-1 shows the overall estimated net benefit for each option under the central scenario.

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



As presented in Figure 7-2, the primary category of benefits for Option 1A, Option 1C and Option 3 is the avoided risk costs, which range from $10.2 million under Option 1C to $12.6 million under Option 1A/1B. The impact on the wholesale market ranges from significant gross benefits (for Option 1B, which have been redacted to preserve confidentiality) to gross market *costs* of $5.1 million (for Option 3). Option 1C is found to have a negligible effect on the wholesale market.

Figure 7-2: Breakdown of present value costs and benefits under the central scenario[25]



The estimated gross wholesale market *cost* for Option 3 is due to it reducing the impedance on the existing 330 kV flow-path from Armidale to Tamworth to Liddell, which increases the proportion of flow across that path relative to the assumed 500 kV route from Armidale to Tamworth to Baywater (the New England REZ augmentation) compared to the proportion in the base case. This is expected to increase the binding constraints in the 330 kV lines from Tamworth to Liddell, resulting in lower transfer limits between northern NSW and central NSW than under the base case and so a wholesale market *cost* from Option 3 (which is the case in all three scenarios modelled). Since NSW demand cannot be met as easily from generation in northern NSW or Queensland in light of the lower transfer limits, more generation capacity is forecast to be built in central NSW than under the base case (which is the primary driver of the market cost for Option 3, i.e., the black bar shown above for Option 3).

7.2. Low economic benefits

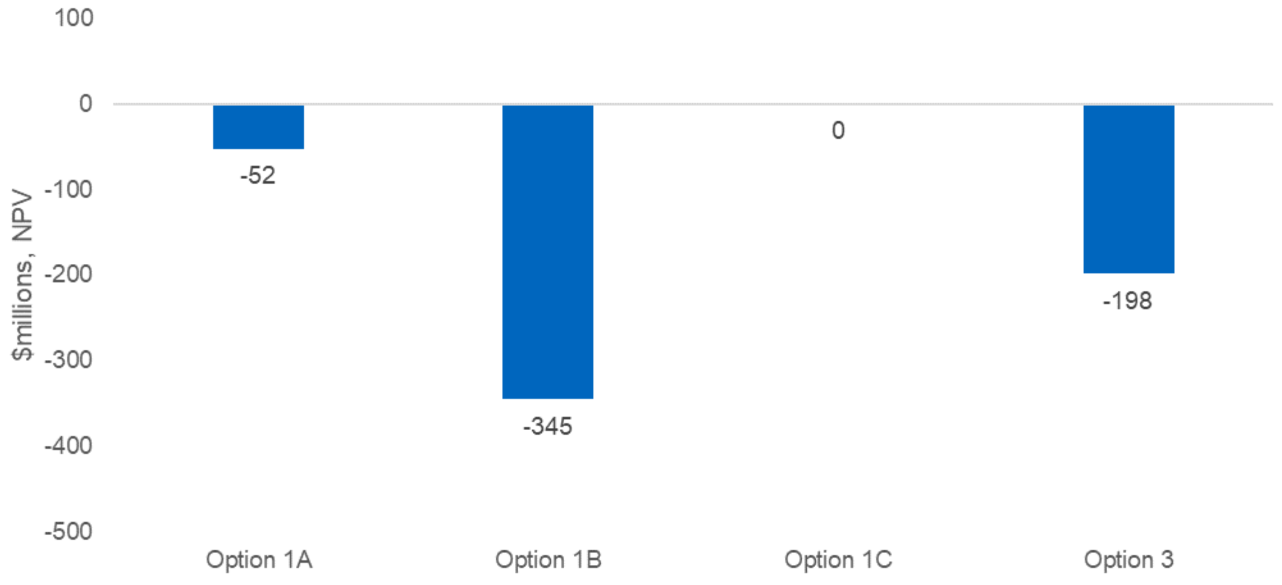
The low net economic benefits scenario reflects a number of assumptions that gives a lower bound and conservative estimate of net present value of net economic benefits. These assumptions include high cost estimates, low risk cost estimates and a high commercial discount rate estimate. This scenario also includes EY's market modelling of the wholesale market benefits under the 2022 ISP progressive change scenario.

Under these assumptions, Option 1C is found to be ranked effectively equal to the option of taking no action (i.e., the 'do nothing' base case), and to deliver approximately $0.1 million in net costs. Each of the other options are expected to deliver substantive net costs under the low benefits scenario, and so to be ranked below the base case, with the next best option (Option 1A) delivering net costs of $52.4 million.

[25] Only the net present value for Option 1B is presented in this figure (and all figures of this type in the PACR) due to confidentiality requirements.

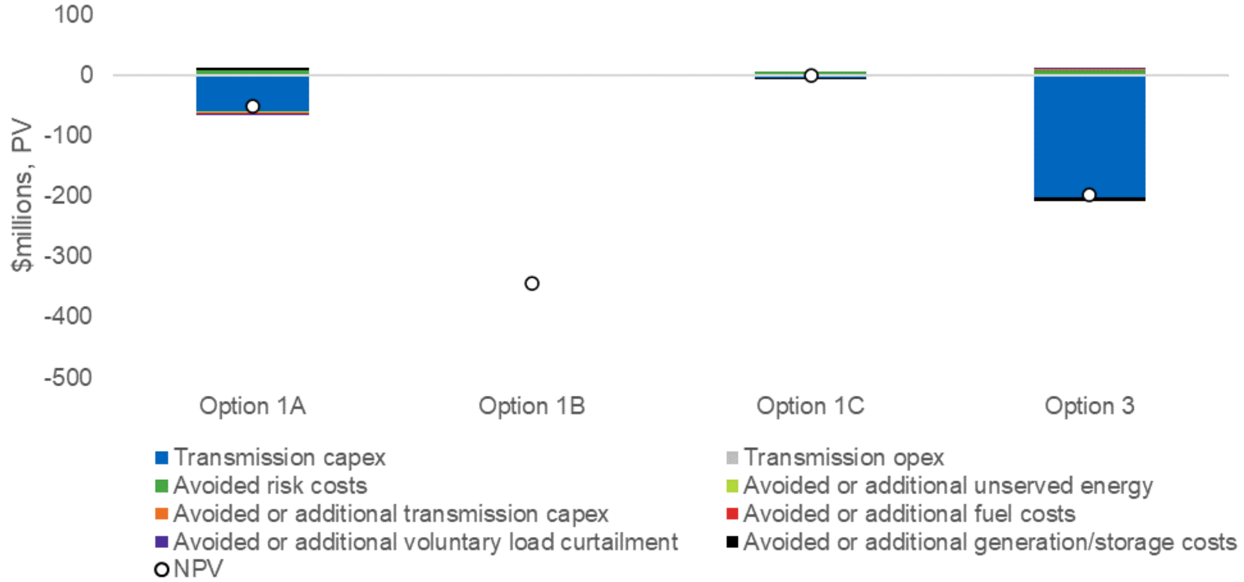
Figure 7-3 shows the overall estimated net benefit for each option under the low benefits scenario.

Figure 7-3: Summary of the estimated net benefits under the low benefits scenario



As presented in Figure 7-4, the primary source of benefit for Option 1A, Option 1C and Option 3 under this scenario continues to be avoided risk costs, which range from $5.8 million under Option 1C to $7.2 million under Option 1A/1B. The impact on the wholesale market ranges from positive gross benefits (for Option 1B, which have been redacted to preserve confidentiality) to gross market costs of $2.9 million (for Option 3). Option 1C is found to have a negligible effect on the wholesale market.

Figure 7-4: Breakdown of present value costs and benefits under the low benefits scenario



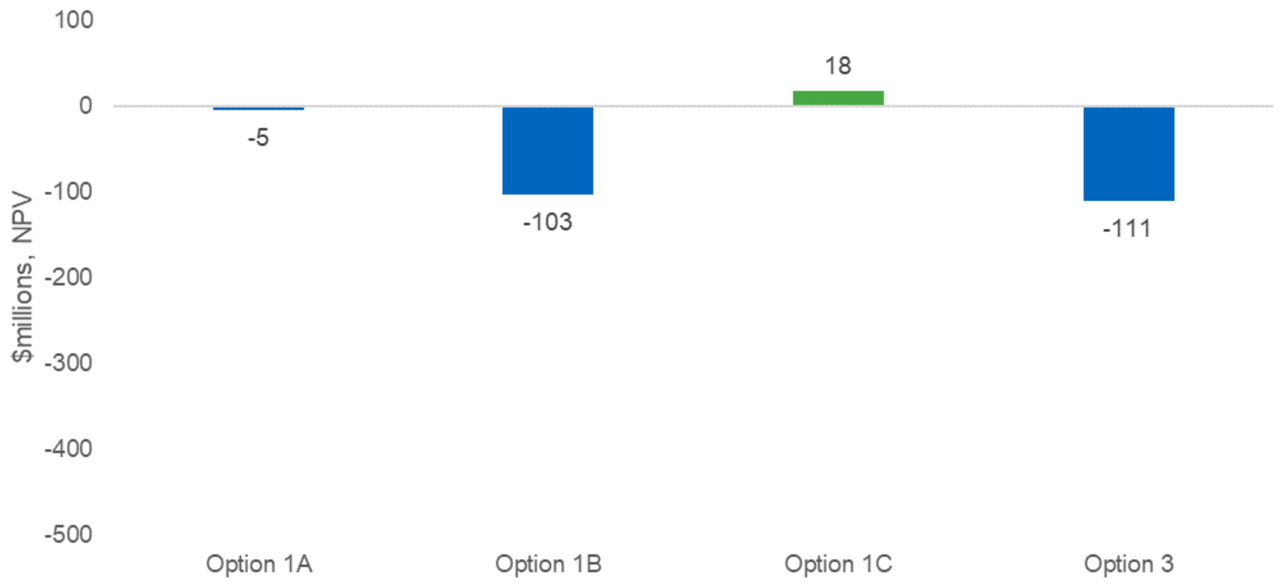
7.3. High net economic benefits

The high net economic benefits scenario reflects a number of assumptions that give an upper bound estimate of net present value of net economic benefits. These assumptions include low cost estimates, high risk cost estimates and a low commercial discount rate estimate. This scenario also includes EY's market modelling of the wholesale market benefits under the 2022 ISP hydrogen superpower scenario.

Under these assumptions, Option 1C is found to be the top-ranked option and to deliver approximately $17.8 million in net benefits. Option 1C is the only option delivering positive net benefits under the high scenario, with the next best option (Option 1A) delivering net costs of $4.6 million and so being ranked below the option of taking no action (i.e., the 'do nothing' base case).

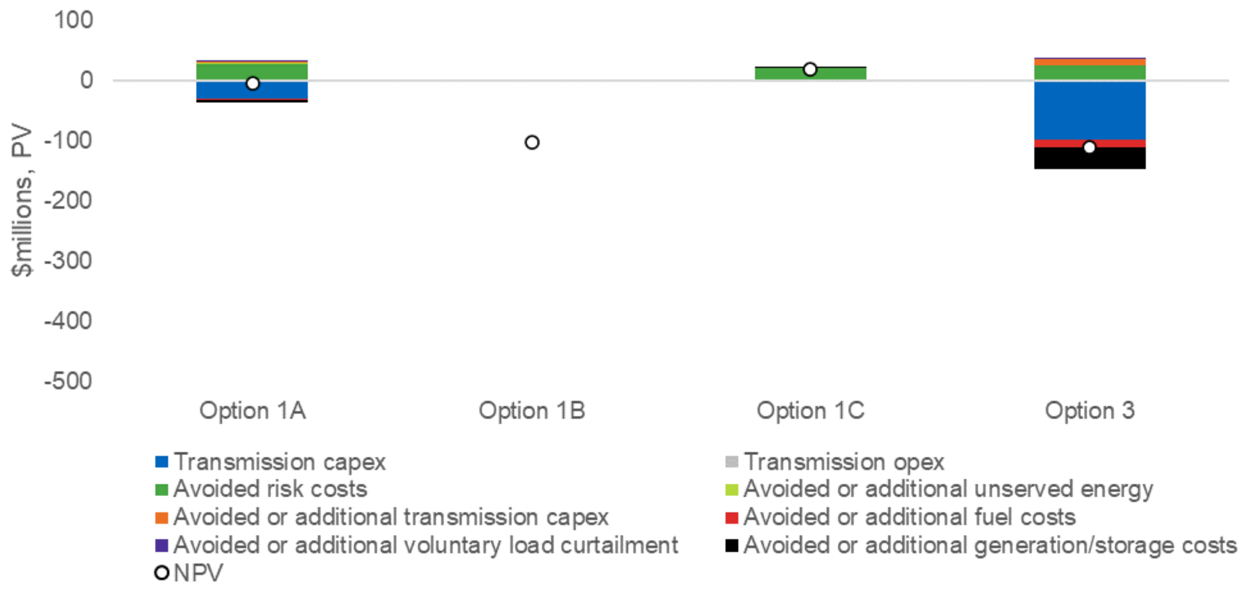
Figure 7-5 shows the overall estimated net benefit for each option under the high benefits scenario.

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



As presented in Figure 7-6, the primary source of benefits for Option 1A, Option 1C and Option 3 is avoided risk costs, which range from $20.5 million under Option 1C to $25.2 million under Option 1A/1B. The impact on the wholesale market ranges from significant gross benefits (for Option 1B, which have been redacted to preserve confidentiality) to gross market costs of $35.3 million (for Option 3). Option 1C is found to have a negligible effect on the wholesale market.

Figure 7-6: Breakdown of present value costs and benefits under the high benefits scenario



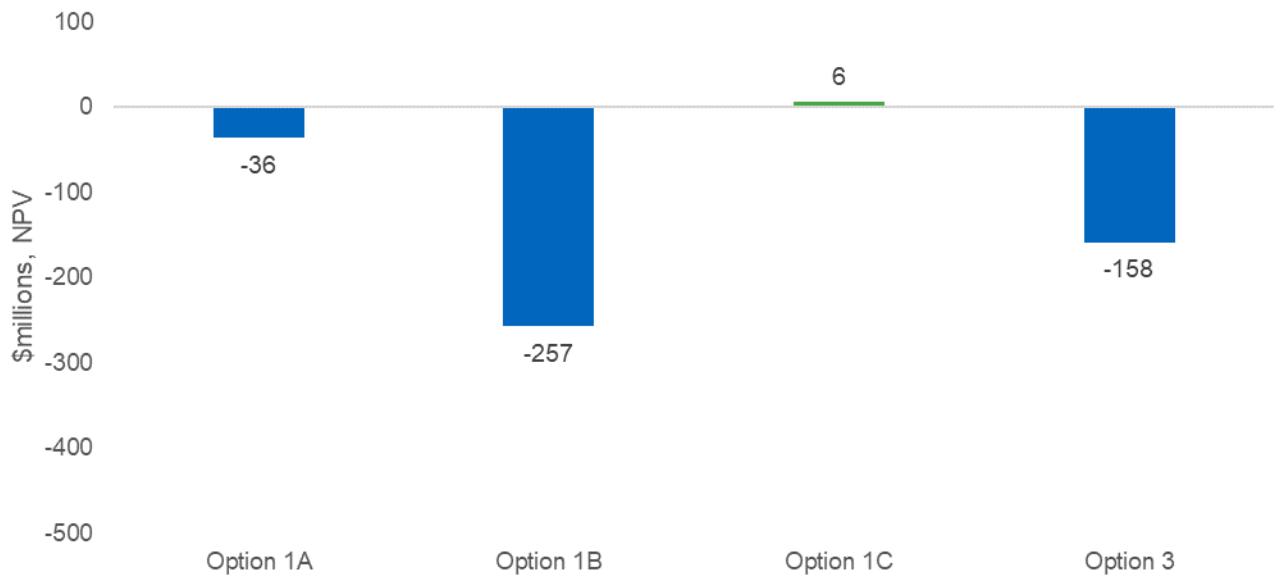
The higher estimated gross wholesale market *cost* for Option 3 under this scenario is driven by the substantially greater levels of renewables and capacity in the hydrogen superpower scenario, compared to the other two 2022 ISP scenarios. This means that the lower transfer limits between northern NSW and central NSW have a greater (negative) impact on the wholesale market than in the other two scenarios and that a greater level of generation capacity is forecast to be built in central NSW, compared to the base case, for Option 3 (which drives the market cost estimated, i.e., the black bar shown above for Option 3).

7.4. Weighted net benefits

Figure 7-7 shows the estimated net benefits for each of the credible options weighted across the three scenarios investigated (and discussed above) using weightings drawn from the 2022 ISP.

Under these assumptions, Option 1C is found to be the top-ranked option and to deliver approximately $6.2 million in net benefits. Option 1C is the only option delivering positive net benefits on a weighted basis, with the next best option (Option 1A) delivering net costs of $35.8 million (and so being ranked below the 'do nothing' base case).

Figure 7-7: Summary of the estimated net benefits, weighted across the three 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 central scenario, which is the most likely scenario.

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

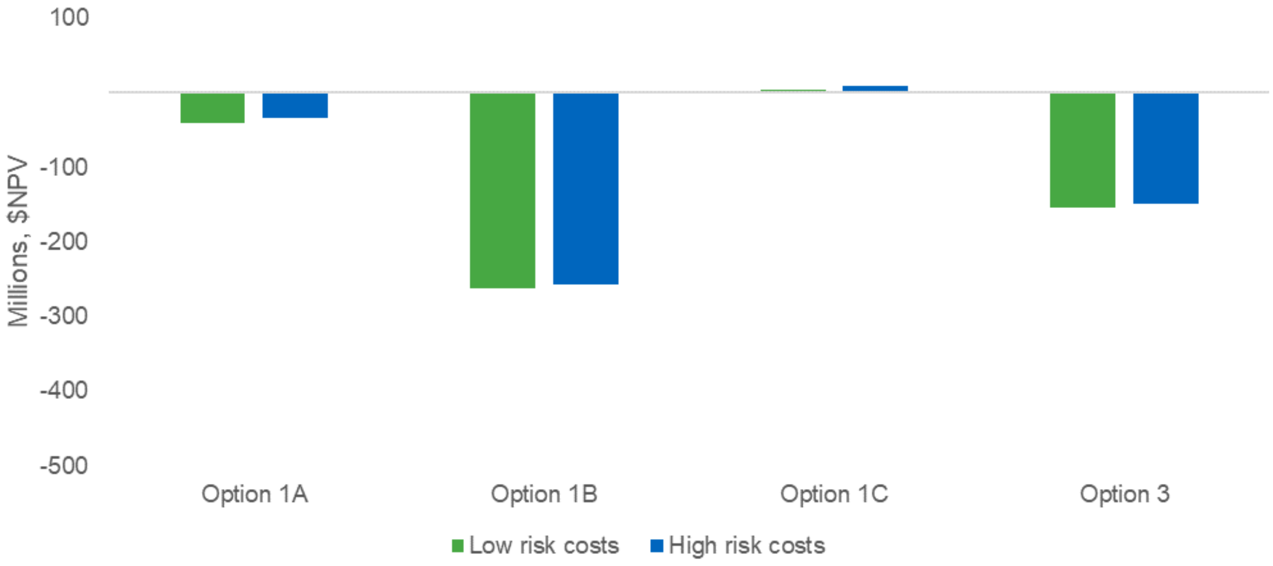
- higher and lower estimated risk costs;
- higher and lower network capital costs;
- higher and lower non-network capital costs; and
- alternate commercial discount rate assumptions.

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

7.5.1. 25 per cent higher and lower assumed risk costs

Figure 7-8 shows that Option 1C continues to be preferred, and to have a positive net benefit, for levels of assumed avoided risk costs between +25 per cent and -25 per cent. In particular, the net benefits of Option 1C range between $3.2 million and $8.3 million in the central scenario for these levels of assumed avoided risk costs.

Figure 7-8: Results with 25% higher and lower assumed risk costs, central scenario

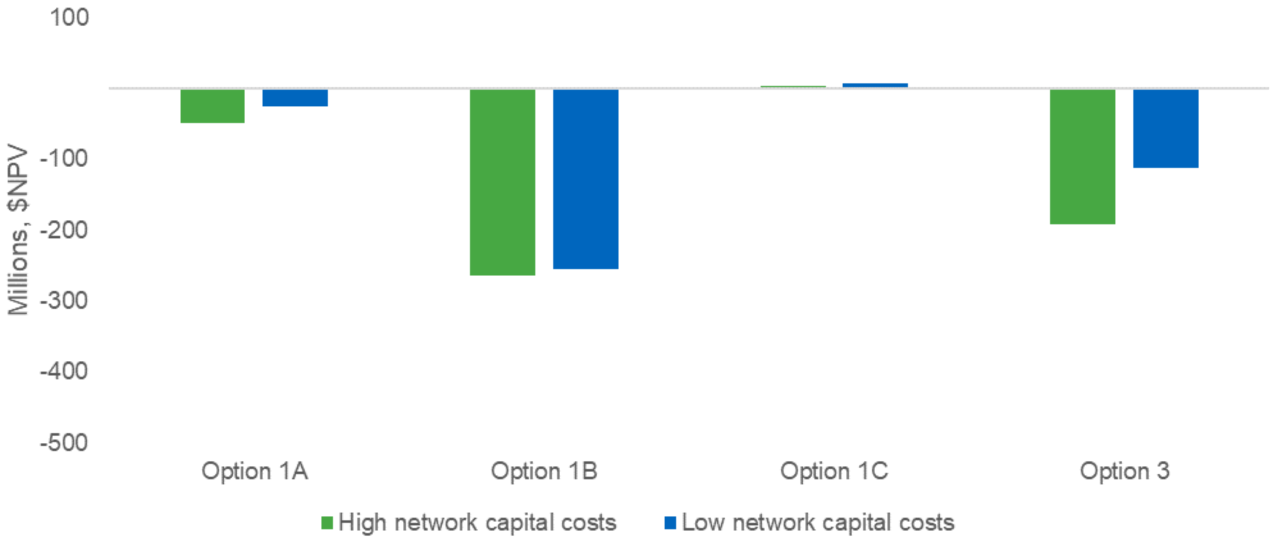


We find that a reduction in risk costs of at least 56 per cent would be required to make the estimated net benefits of Option 1C negative in the central scenario.

7.5.2. 25 per cent higher and lower network capital costs

Figure 7-9 finds that the preferred option, Option 1C, is expected to deliver $4.6 million in net benefits in the central scenario with 25 per cent higher network capital costs and $6.9 million in net benefits in the central scenario with 25 per cent lower network capital costs. Option 1C remains the top-ranked credible option under both higher and lower assumed network capital costs.

Figure 7-9: Results with 25% higher and lower network capital costs, central scenario



We find that there is no realistic increase in network capital costs that would make the estimated net benefits of Option 1C negative in the central scenario. Specifically, we find that network capital costs would need to increase by more than 123 per cent in order for Option 1C to have negative estimated net benefits in the central scenario.

7.5.3. Higher and lower non-network capital costs

In order to preserve the requested confidentiality by the proponent of Option 1B, the non-network capital cost sensitivity results are not presented in detail in this PACR. However, we can confirm that there is no realistic change in non-network capital costs that would make the net benefits of Option 1B positive in the central scenario, or change the rankings of the options.

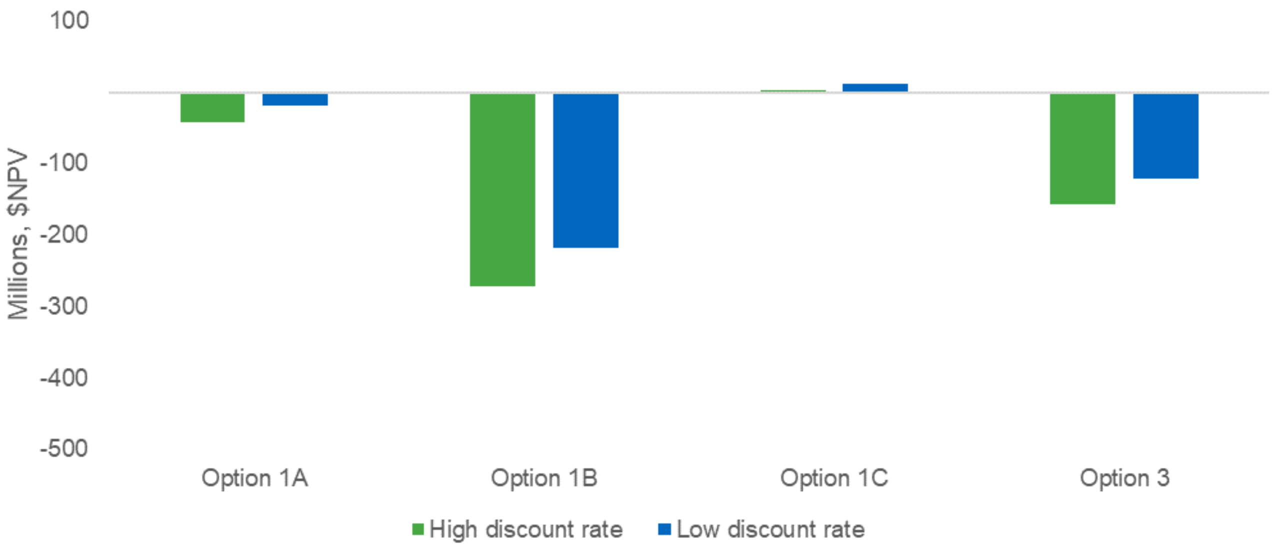
7.5.4. Alternative commercial discount rate assumptions

Figure 7-10 illustrates the sensitivity of the results in the central scenario to different discount rate assumptions in the NPV assessment. In particular, it illustrates two tranches of net benefits estimated for each credible option – namely:

- a high discount rate of 7.50 per cent; and
- a low discount rate of 2.30 per cent.

Figure 7-10 shows that the preferred option, Option 1C, is expected to deliver $3.3 million in net benefits under the high discount rate and $12.5 million in net benefits under the low discount rate. Option 1C remains the top-ranked credible option under both a higher and lower assumed commercial discount rate.

Figure 7-10: Results with higher and lower commercial discount rate assumptions, central scenario



We find that a discount rate higher than 12.8 per cent would be required to make the estimated net benefits of Option 1C negative in the central scenario.

8. Conclusion

This PACR finds that a focused replacement of the highest risk Line 86 wood poles, like for like and in-situ with concrete or steel poles ('Option 1C') is the preferred option for meeting the identified need on a weighted basis and in the sensitivities assessed. Option 1C is expected to deliver approximately $6.2 million in net benefits over the 19-year assessment period (on a weighted-basis).

Option 1C satisfactorily reduces the bushfire risk posed by the deteriorating poles on Line 86, and avoids significant expected costs associated with reactive maintenance (which may need to be done under emergency conditions).

The PACR assessment shows that the additional costs of replacing Line 86 with either a higher capacity line or in combination with a VTL (i.e., Option 3 and Option 1B) are not outweighed by any additional wholesale market benefits.

Option 1C involves replacing the 31 highest risk poles of Line 86 between 2025-26 and 2027-28 (making up approximately 8 per cent of the remaining poles to be replaced/remediated). We note that the replacement of the remaining poles on Line 86 would be subject to a separate RIT-T in the future to determine whether this work is justified (and in what form).

The estimated capital cost of replacing the 31 highest risk poles of Line 86 under Option 1C is approximately $10.65 million.

We consider that this PACR confirms Option 1C as the option that satisfies the RIT-T.

Appendix A – Compliance checklist

This appendix sets out a compliance checklist which demonstrates the compliance of this PACR with the requirements of clause 5.16.4 of the Rules version 183.

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 & 7
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	6 & Appendix B
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	6.5
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	7
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	7
	(8) the identification of the proposed preferred option;	8
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	4 and 8

Appendix B – Overview of the wholesale market modelling undertaken

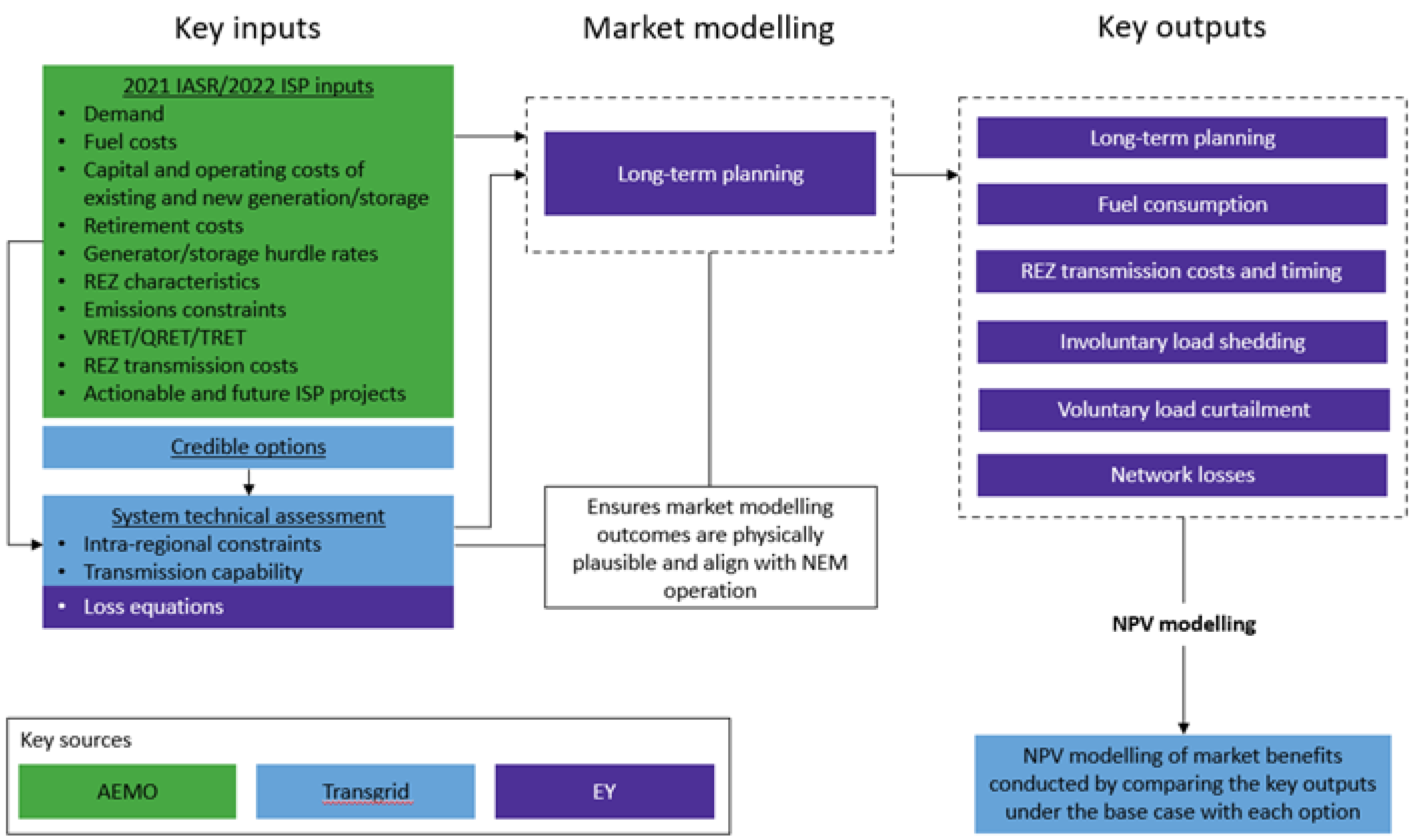
As outlined in the body of this PACR, we engaged EY to undertake the wholesale market modelling as part of this PACR.

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 B-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 B-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 case.

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 battery storage state of charge do not breach maximum and minimum values and cyclic losses are accounted for;
- new generation capacity is connected to locations in the network where it is most economical from a whole of system cost;
- NEM-wide emissions constraints are adhered to;
- NEM-wide and state-wide renewable energy targets are met;
- 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).[26]

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 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.

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

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.

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 B-1: PACR modelled scenario's key drivers input parameters

Key drivers input parameters	Step change	Progressive change	Hydrogen superpower
Underlying consumption	ESOO 2021 (ISP 2022) – step change	ESOO 2021 (ISP 2022) – progressive change	ESOO 2021 (ISP 2022) – hydrogen superpower
Committed and anticipated generation	Latest committed and anticipated generators from the Generation Information Page, published in June 2022		

Key drivers input parameters	Step change	Progressive change	Hydrogen superpower
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PSH, and large-scale batteries	2022 ISP Inputs, Assumptions and Scenarios Workbook – step change	2022 ISP Inputs, Assumptions and Scenarios Workbook – progressive change	2022 ISP Inputs, Assumptions and Scenarios Workbook – hydrogen superpower
Retirements of coal-fired power stations	2022 ISP Inputs, Assumptions and Scenarios Workbook – step change In line with expected closure year, or earlier if economic or driven by decarbonisation objectives	2022 ISP Inputs, Assumptions and Scenarios Workbook – progressive change In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030	2022 ISP Inputs, Assumptions and Scenarios Workbook – hydrogen superpower In line with expected closure year, or earlier if economic or driven by decarbonisation objectives
Gas fuel cost	2022 ISP Inputs, Assumptions and Scenarios Workbook – step change Lewis Grey Advisory 2020, step change	2022 ISP Inputs, Assumptions and Scenarios Workbook – progressive change Lewis Grey Advisory 2020, central	2022 ISP Inputs, Assumptions and Scenarios Workbook – hydrogen superpower Lewis Grey Advisory 2020, step change
Coal fuel cost	2022 ISP Inputs, Assumptions and Scenarios Workbook – step change Wood Mackenzie, step change	2022 ISP Inputs, Assumptions and Scenarios Workbook – progressive change Wood Mackenzie, central	2022 ISP Inputs, Assumptions and Scenarios Workbook – hydrogen superpower Wood Mackenzie, step change
NEM carbon budget to achieve 2050 emissions levels	2022 ISP Inputs, Assumptions and Scenarios Workbook – step change 891 Mt CO_2-e 2023-24 to 2050-51	2022 ISP Inputs, Assumptions and Scenarios Workbook – progressive change 932 Mt CO_2-e 2030-31 to 2050-51	2022 ISP Inputs, Assumptions and Scenarios 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)	2022 ISP Inputs, Assumptions and Scenarios Workbook: 200 % Renewable generation by 2040		
NSW Electricity Infrastructure Roadmap	2022 ISP Inputs, Assumptions and Scenarios Workbook: 12 GW NSW Roadmap, with 3 GW in the Central West Orana (CWO) REZ, modelled as generation constraint per the 2022 ISP 2 GW of long duration storage (8 hrs or more) by 2029-30		
EnergyConnect	2022 ISP Report note – EnergyConnect fully commissioned by July 2026		
Western Victoria Transmission Network Project	2022 ISP – Western Victoria upgrade commissioned by July 2026		
HumeLink	2022 ISP – step change: HumeLink commissioned by July 2028	2022 ISP – progressive change: HumeLink commissioned by July 2035	2022 ISP – hydrogen superpower: HumeLink commissioned by July 2027
Marinus Link	2022 ISP – 1st cable commissioned by July 2029 and 2nd cable by July 2031		
Victoria to NSW Interconnector Upgrade (VNI Minor)	2022 ISP – VNI Minor commissioned by December 2022		
NSW to QLD Interconnector Upgrade (QNI Minor)	2022 ISP – QNI minor commissioned by mid-2023		
QNI Connect	2022 ISP – step change: QNI Connect commissioned by July 2032	2022 ISP – progressive change: QNI Connect commissioned by July 2036	2022 ISP – hydrogen superpower: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030

Key drivers input parameters	Step change	Progressive change	Hydrogen superpower
VNI West	2022 ISP – step change: VNI West commissioned by July 2031	2022 ISP – progressive change: VNI West commissioned by July 2038	2022 ISP – hydrogen superpower: VNI West commissioned by July 2030
Victorian SIPS	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. After SIPS contract ends (March 2032) 300 MW can be deployed in the market by the operator on a commercial basis.		
New-England REZ Transmission	2022 ISP – step change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	2022 ISP – progressive change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	2022 ISP – hydrogen superpower: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2031
Snowy 2.0	2022 ISP Inputs, Assumptions and Scenarios Workbook – Snowy 2.0 is commissioned by December 2026		