Transgrid

Maintaining Reliable Supply to the North West Slopes Area

RIT-T - Project Assessment Conclusions Report [Amended]

Region: Northern New South Wales

Date of issue: 31 January 2023

People. Power. Possibilities.

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Executive summary

We have applied the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining reliable supply to the North West Slopes area of northern New South Wales (NSW). An initial Project Assessment Conclusions Report (PACR) was released for this RIT-T on 30 June 2022 (referred to throughout this document as the 'initial PACR').

On 1 August 2022, the Australian Energy Regulator (AER) received a dispute notice from the Public Interest Advocacy Centre (PIAC), contending that Transgrid may have incorrectly applied the RIT-T in the initial PACR. On 29 November 2022, the AER released its determination on the dispute and has required Transgrid to amend the PACR in a number of areas by 1 February 2023.

This amended PACR therefore updates the assessment and PACR in-line with the AER dispute determination. The amended PACR only varies from the initial PACR to the extent necessary to reflect the changes made to the scenario assumptions in light of the AER determination, to present the revised results and to provide the additional information requested by the AER. We have engaged with the AER on the approach for amending the PACR and consider that this document fully aligns with the direction provided in the determination and those subsequent discussions.

The time taken to address the RIT-T dispute and may change the availability of network and non-network solutions beyond the expected timing considered in this PACR. This will be assessed during the competitive procurement process and commercial negotiations with non-network proponents. However, we consider that any change is likely to equally apply to both network and non-network options and will therefore not materially impact the relative benefits or ranking of options presented in this amended PACR.

Overview

The preferred option identified in this amended PACR remains unchanged from the initial PACR and involves a non-network solution provided through a BESS at the Gunnedah 132 kV substation and the installation of a third 60 MVA 132/66 kV transformer at the Narrabri 132/66 kV substation in the near-term. It also involves the rebuilding of the existing 969 line between the Tamworth 330 kV and Gunnedah substations as a double circuit line and upgrading the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA over the longer-term, depending on outturn demand forecasts.

The proposals of two separate third party non-network BESS proponents have been found to be ranked effectively equal in the PACR assessment. These options are referred to as Option 5B and Option 5C in the PACR, and reflect the proposed BESS component followed by the network investment outlined above. These options are found to deliver approximately $459 million and $441 million in net benefits, respectively, relative to the 'do nothing' base case on a weighted basis, which compares to $419 million for the preferred solely network option (Option 3A).[1] The proposal of the third BESS proponent (assessed as Option 5A) has been found to deliver lower net benefits than these two options but to effectively be ranked equally with Option 3A.

The non-network solutions will provide up to 57 MW and 20 MVAr in the Gunnedah area, providing both network and dynamic reactive support by 2030 to manage thermal constraints and voltage variations during high demand periods. Options with non-network solutions generally have higher net benefits because they can be deployed an estimated one to two years earlier than the pure network options, avoiding significant unserved energy in that period.

[1] Option 3A includes an additional network component to Options 5A-5C, as well as earlier investment in some components.

We will now enter into a competitive procurement process and commercial negotiations with non-network proponents for a network support contract and seek to put in place a contract with one of these parties. We consider these negotiations should involve all proponents involved in the RIT-T process (i.e., including the proponent for Option 5A, which has lower estimated net benefits than the other two non-network options) and potentially others who are able to provide the same kind of solution within the required timeframe, since the timing of when a BESS can be implemented is critical to which solution is ultimately preferred (and may be able to be refined through the negotiation process). In addition, we consider that having more parties involved in this process will ensure that the network support costs paid for by consumers are as efficient as possible.

Notwithstanding the above, we consider that if either of the following two events occur, they would likely constitute a 'material change in circumstances' (i.e., under clause 5.16.4(z3) of the NER):

1. None of the non-network proponents being able to commit to having the BESS in place to provide network support by a date that ensures that option continues to be considered as the top-ranked option under the RIT-T; or
2. Transgrid not being able to finalise a network support contract with any of the proponents that is expected to be accepted as prudent and efficient by the AER.

Should either (or both) of these events occur, we would seek an exemption from the AER under clause 5.16.4(z3) of the NER to avoid having to reapply the RIT-T. Specifically, we consider that, should either of the above events occur, then the analysis presented in this PACR demonstrates that Option 3A (i.e., the top ranking solely network option) should then be considered the preferred option under this RIT-T.

We consider this approach provides sufficient confidence that Transgrid will be able to progress an option to ensure the externally-imposed regulatory obligations and service standards this RIT-T is designed to meet are met at an efficient cost level without having to re-do the RIT-T. We note that re-doing the RIT-T would take significant time, which would compromise the reliability of supply to customers in the North West Slopes area and ultimately likely cost all NSW electricity customers more in the long-run.

We will update stakeholders when we consider that the network support agreement for one of these options is sufficiently certain, or at the point we determine there has been a material change in circumstances and that the investment should be progressed as a solely network option (i.e., Option 3A) (i.e., when we would submit an exemption to the AER from having to reapply the RIT-T).

All non-network options, as well as Option 3A, are expected to generate sufficient benefits to recover their costs within **two years** of commissioning their respective long-term solutions (under the weighted results and in present value terms).

The identified need driving investment

Our latest forecasts indicate that electricity demand is expected to increase substantially in the North West Slopes area going forward due to a number of substantial industrial loads that are anticipated to connect, as well as underlying general load growth in Narrabri and Gunnedah.

Schedule 5.1.4 of the National Electricity Rules (NER) requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage.[2] The NER also requires the power

2 These levels are specified in Clause S5.1a.4.

system to be operated in a satisfactory operating state, which requires voltages to be maintained within these levels, both in normal operation and following any credible contingency event.[3]

We have undertaken planning studies that show that the current North West Slopes network will not be capable of supplying the combined increases in load in the area without breaching the NER requirements and that voltage-limited constraints will have to be applied in the 132 kV supply network if action is not taken, leading to substantial levels of unserved energy to end customers. Our planning studies also show that the increased demand will also lead to thermal constraints going forward, particularly during times of low renewable generation dispatch in the region.

If the longer-term constraints associated with the load growth are unresolved, it could result in the interruption of a significant amount of electricity supply under both normal and contingency conditions due to voltage and thermal limitations in the area.

This RIT-T has therefore examined various network and non-network options for relieving these constraints going forward to ensure compliance with the requirements of the NER and provide the greatest net benefit to the market. We consider this a 'reliability corrective action' under the RIT-T as the proposed investment is for the purpose of meeting externally-imposed regulatory obligations and service standards, i.e., Schedule 5.1.4 of the NER.

Benefits from the options considered in this PACR

Without action, voltage-limited constraints will have to be applied in the 132 kV supply network that will lead to substantial levels of unserved energy to end customers. We are taking action under this RIT-T in order to avoid this outcome. All of the credible options have been designed to maximise the avoided unserved energy expected and ensure compliance with the requirements of the NER.

In addition, some of the credible options assessed also affect the wholesale electricity market. In particular, four of the options involve grid-connected BESS that are expected to introduce new entities trading in the wholesale market, eg, dispatching into the National Electricity Market (NEM) outside of the allocation of storage needed to meet network support commitments.

Both the benefits from the provision of reliable supply to the North West Slopes area and wider wholesale market benefits have been estimated as part of this PACR.

Key developments since the PADR have been reflected in the PACR

There have been a number of key developments since the Project Assessment Draft Report (PADR) was released in February 2022, which impact the analysis in this RIT-T. In particular:

- the demand forecasts have been updated based on additional information provided by proponents of new or expanded industrial spot loads, as well as updated information on general load growth from Essential Energy;
- our forecasts of when voltage and thermal limits are expected to be breached have been updated in light of the revised demand forecasts;

[3] These requirements are set out in Clauses 4.2.6, 4.2.4 and 4.2.2(b) of the NER. The requirement for secure operation of the power system in Clause 4.2.4 requires the power system to be in a satisfactory operating state following any credible contingency event, that is, to maintain voltage within 10 per cent of normal voltage following the first credible contingency event.

- the wholesale market modelling has been updated to reflect the assumptions underpinning AEMO's 2022 Integrated System Plan (ISP) and is now focused on the Step Change, Progressive Change and Hydrogen Superpower scenarios (the scenario weightings have also been updated to be consistent with the 2022 ISP);
- there have been a number of updates to the non-network options that were assessed in the PADR (Option 5A and Option 5B), including to reflect new information provided by the proponents;
- a new non-network option (Option 5C) has been included in the assessment following a submission to the PADR;
- there has been an update to the assumptions regarding how BESS components are likely to be able to trade in the wholesale market, based on further analysis of the amount of storage that would be required to be reserved to provide network support; and
- there have been a number of updates to the network options, including revised costs and reactive support sizing.

The key changes in the PACR demand forecasts compared to the PADR are:

- Essential Energy providing revised general demand forecasts for the region as part of an annual update;
- the inclusion of the Narrabri Coal expansion in the central demand forecast (this is a new spot load that was not included in Essential Energy's demand forecasts at the time of the PADR); and
- a one year delay to the commencement of the expansion of the existing Vickery Coal Mine (VCM).

The last two changes above reflect additional information provided by proponents following the PADR.

There has been no change to the Narrabri Gas Project load reflected in the demand forecasts since the PADR.

We received submissions from four parties in response to the PADR. While submissions covered a range of topics, there were five main topics that emerged:

- a new non-network option was proposed by one submitter (and has been included in the PACR assessment as a new Option 5C);
- further details regarding earlier proposed non-network options were provided by the proponents;
- uncertainty around the demand forecasts;
- a proposal for an alternate conductor technology, that could reduce the network option costs; and
- the appropriateness of the 'high benefits' scenario in the PADR.

The key matters raised in public submissions relevant to the RIT-T assessment are summarised in this PACR, together with our responses and how the matters raised have been reflected in the assessment. Many of the submissions were confidential and we have engaged directly with those parties on the points raised.

We note that this amended PACR does not reflect any further changes to the assumptions since the initial PACR, other than those made as a consequence of the AER's dispute determination. This is consistent with the AER's view that, as a principle, they expect Transgrid to apply the same information that was available at the time of the PACR, unless Transgrid considers that there has been a material change in circumstances as defined in the NER. We have however presented a sensitivity with increased costs for the network component of the options, to reflect our latest unit rates, in line with our revised Regulatory Proposal.

The PACR assessment covers four different types of credible options

This PACR assesses both network options and options involving non-network components followed by network investment.[4]

Each of the credible network options requires the installation of a third 60 MVA 132/66 kV transformer at Narrabri due to the firm supply capacity of the existing transformers at this location being exceeded and to ensure the reliability standard set by the Independent Pricing and Regulatory Tribunal (IPART) is met for Narrabri in the short-term.

Aside from the new 132/66 kV transformer at Narrabri, the credible network options assessed differ in the near-term by where, how and when new capacity is added to the North West Slopes region. In particular, there are three broad types of credible network option assessed that centre on:

- uprating the existing line 969 from Tamworth to Gunnedah (Option 1A and Option 1B);
- installing new single or double circuit transmission lines between Tamworth and Gunnedah (Option 2A, Option 2B, Option 2C and Option 2D); and
- rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line (Option 3A, Option 3B and Option 3C).

Most credible options include the provision of dynamic reactive support at Narrabri provided by an SVC or grid-scale BESS. Two options (Option 2C and Option 3C) involve a new transmission line between Gunnedah and Narrabri as an alternative to dynamic reactive support and the upgrade to the 9UH line.

While there have been no material changes to the network options since the PADR, the non-network options considered in the PACR assessment have been refined to reflect:

- submissions to the PADR, resulting in the timing of Option 5A being brought forward by six months from the PADR, minor revisions to the estimated costs of Option 5A and Option 5B and the inclusion of a third non-network option (Option 5C); and
- elements of the non-network options being resized and rescoped following additional information provided by proponents.

The non-network solutions have been modelled in terms of their ability to efficiently defer or avoid the rebuilding of line 969 as a double-circuit line,[5] which is part of the preferred solely network option (Option 3A).

Non-network options are not able to avoid or defer the need for the initial third transformer required at Narrabri, since capacity is required there immediately to ensure the reliability standard set by IPART is met at Narrabri. The non-network options therefore reflect a combination of an initial non-network component

[4] Non-network options by themselves are not expected to be able to meet the identified need over the entire assessment period.
[5] The rebuilding of this line is required when the Narrabri Gas Project comes online.

and a third Narrabri transformer in all scenarios, followed by a deferred rebuilding of line 969 as a double-circuit line and upgrading the 9UH line between Narrabri and Boggabri North in the Step Change and Hydrogen Superpower scenarios when the Narrabri Gas Project comes online.

Table E-1.1 below summarises each of the credible options assessed in the PACR.

Table E-1.1: Summary of the credible options

Option	Description	Estimated capex ($2020/21)
	Uprating the existing line 969 from Tamworth to Gunnedah	
1A	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA	• $51 million
	• Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah substation	• $18 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Upgrade the existing 968 line between Tamworth 330 and Narrabri substations to a rating of at least 160 MVA	• $149 million
	• Install a 132 kV +60 MVAr -20 MVAr SVC at Narrabri	• $20 million
1B	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA	• $51 million
	• Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah substation	• $18 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Build a new 132 kV line between Tamworth 330/132 kV and Narrabri 132/66 kV substations	• $160 million
	New single or double circuit transmission lines between Tamworth and Gunnedah	
2A	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah substations.	• $73 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $28 million
	• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million

Option	Description	Estimated capex ($2020/21)
2B	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new double circuit 132 kV line between the Tamworth 330 kV and Gunnedah substations, each circuit rated at 160 MVA. Decommission the existing 969 transmission line	• $89 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $28 million
	• Installation of a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
2C	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah substations	• $73 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Build a new single circuit 132 kV line between Narrabri and Gunnedah	• $106 million
2D	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 330 kV line between Tamworth 330 kV and Gunnedah substations operated at 132 kV, rated at least 160 MVA	• $159 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $28 million
	• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
Rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line		
3A	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Install a 132 kV +60 MVAr (capacitive) -20 MVAr (inductive) SVC at Narrabri substation	• $20 million
3B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Install a 50 MW (50 MWh) BESS at Narrabri 132 kV	• Confidential
3C	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Build a new single circuit 132 kV line between Narrabri and Gunnedah	• $106 million
Combination of non-network solutions with the top-ranked network option (Option 3A)		

Option	Description	Estimated capex ($2020/21)
5A	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS at Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
5B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS near Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
5C	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS at Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million

Capital costs for the network options have been revised since the PADR to reflect the change in size of some elements, as well as to reflect current market trends and risks, drawing on the experience of recent projects. In addition, works for the line 969 double-circuit rebuild, and the 9UH line uprating, now reflect the use (and costs) of an alternate conductor technology proposed in response to the PADR.

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. While the scenarios in the initial PACR were designed to comprehensively test the range of net benefits that can be expected from the credible options, they have now been updated in-line with the AER dispute determination to align with those in AEMO's 2021 Input and Assumptions Report (IASR), which underpins the 2022 Integrated System Plan (ISP).

Specifically, the three scenarios now reflect the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2021 IASR and only vary by local spot load forecasts and new local renewable generation assumptions (since these two parameters have material impacts on the assessment of the options). The scenarios no longer vary the assumed network or non-network capital costs, the VCR or discount rate. This approach has been discussed and agreed with the AER following their dispute determination.

The table below summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered. It also shows where there has been a change in an assumption from the initial PACR following the AER dispute determination (where the initial assumption is shown italicised in parentheses).

Table E.1.2: Summary of scenarios (and comparison with initial PACR)

Variable	Step Change	Progressive Change	Hydrogen Superpower
Network capital costs	Base estimate	Base estimate *(Base estimate + 25%)*	Base estimate *(Base estimate - 25%)*
Non-network capital costs	Base estimate	Base estimate *(Base estimate + 25%)*	Base estimate *(Base estimate - 25%)*
Demand	Central demand forecast (as outlined in section 2.3.1)	Low demand forecast (as outlined in section 2.3.1)	Central demand forecast (as outlined in section 2.3.1)
New renewable generation in the area[6]	In-service generators from Appendix B.	In-service generators from Appendix B. *(All in-service and advanced generators)*	In-service and advanced generators from Appendix B. *(All in-service generators)*
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
VCR[7]	\$46.88/kWh	\$46.88/kWh *(\$32.82/kWh)*	\$46.88/kWh *(\$60.95/kWh)*
Discount rate	5.50%	5.50% *(7.50%)*	5.50% *(1.96%)*

The wholesale market modelling has been updated since the PADR to reflect the market benefits of the options (where relevant) across the three ISP scenarios. We have weighted each of the scenarios for this RIT-T based on the ISP weightings, i.e.:

- 52 per cent to the Step Change scenario;
- 30 per cent to the Progressive Change scenario; and
- 18 per cent to the Hydrogen Superpower scenario.

6 Please note that this table no longer refers to 'committed' generators as there are none for the NW Slopes area, as outlined in Appendix B.
7 The VCRs used in this PACR have been updated since the PADR to reflect the updated underlying demand forecasts, i.e., the load that would be affected under the base case. However, we note that this update has had only a minor impact on the estimated VCRs.

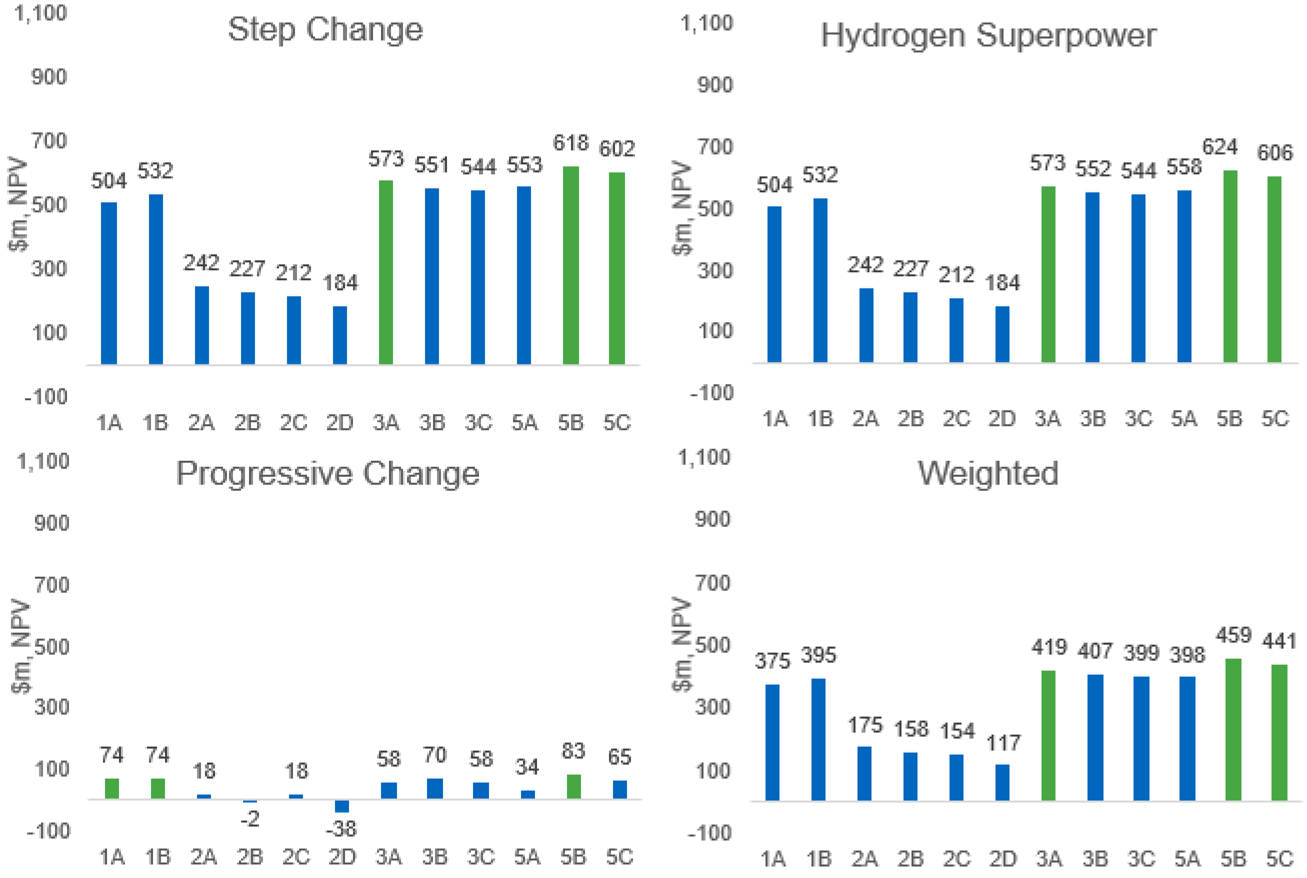
We have also investigated the sensitivity of the results to alternate weightings as part of this PACR (and they are found not to be sensitive).

The preferred option involves the use of BESS in the short-term coupled with network investment as demand grows

The preferred option identified in this amended PACR is the same as the initial PACR and involves the use of a non-network solution provided via a new BESS at the Gunnedah 132 kV substation and the installation of a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation in the near-term. It also involves rebuilding of the existing 969 line between the Tamworth 330 kV and Gunnedah substations as a double circuit and upgrading the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA over the longer-term, depending on outturn demand forecasts.

The proposals of two separate third party BESS proponents (coupled with network investment) have been found to be ranked effectively equal in the PACR assessment. These options are referred to as Option 5B and Option 5C in the PACR and are found to deliver approximately $459 million and $441 million in net benefits, respectively, relative to the ‘do nothing’ base case on a weighted basis, which compares to $419 million for the top-ranked solely network option (Option 3A).

Figure E-1.1: Estimated net benefits for each scenario



Option 5B has the greatest estimated net benefits on a weighted basis and in each scenario. This is a minor change from the initial PACR, where Option 5B was the top option on a weighted basis and in the central and high economic benefits scenarios assessed at the time, but not in the low economic benefits scenario.

The proposal of the third BESS proponent (Option 5A) has been found to deliver lower net benefits than Option 5B and Option 5C and effectively be ranked equally with Option 3A.

While Option 3A has the second lowest expected total cost of the solely network options, in present value terms, under the weighted outcome, it can avoid a substantial amount of unserved energy one to two years earlier than the lowest cost network option (Option 2B).[8] Option 3A also has the lowest cost, in real terms, of the solely network options. Option 3A is therefore considered the preferred solely network option and is therefore the network option the non-network options have been coupled with.[9]

Almost all of the estimated gross benefits across all of the options are derived from avoided unserved energy, which makes up between 88 and 91 per cent of the total gross benefits of Options 5A-5C on a weighted basis (and 100 per cent for Option 3A since that option does not affect the wholesale market). We note also that we have applied a conservative approach to valuing these benefits, whereby all unserved energy in the later years of the assessment period is not valued (since it is common to all options), in order to enable the most meaningful comparison between options.

Moreover, while Option 5C is ranked below Options 1A, 1B and 3B in the Progressive Change scenario, the Progressive Change scenario would need to be weighted at least 88 per cent, with the other two scenarios weighted relative to their ISP weights, for Option 5C to be ranked below a purely network option on a weighted basis. We consider this unlikely. As noted above, Option 5B is top ranked across all scenarios.

Further information and next steps

This amended PACR represents the final formal stage in the RIT-T process, and follows the AER's determination on the dispute lodged in response to the initial PACR.

We will now enter into a competitive procurement process and commercial negotiations with non-network proponents for a network support contract and seek to put in place a contract with one of these parties.

Notwithstanding the above, we consider that if either of the following two events occur, they would likely constitute a 'material change in circumstances' (i.e., under clause 5.16.4(z3) of the NER):

1. None of the non-network proponents being able to commit to having the BESS in place to provide network support by a date that ensures that option continues to be considered as the top-ranked option under the RIT-T; or

2. Transgrid not being able to finalise a network support contract with any of the proponents that is expected to be accepted as prudent and efficient by the AER..

Should either (or both) of these events occur, we would seek an exemption from the AER under clause 5.16.4(z3) of the NER to avoid having to reapply the RIT-T. Specifically, we consider that, should either of

8 The present value of all capex and opex of Option 3A under the weighted outcome is $91 million, which compares to $83 million for Option 2B.
9 The non-network solutions are able to defer or avoid the rebuilding of line 969 as a double-circuit line under Option 3A.

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the above events occur, then the analysis presented in this PACR demonstrates that Option 3A (i.e., the top ranking solely network option) should then be considered the preferred option under this RIT-T.

We consider this approach provides sufficient confidence that Transgrid will be able to progress an option to ensure the externally-imposed regulatory obligations and service standards this RIT-T is designed to meet are met at an efficient cost level without having to re-do the RIT-T. We note that re-doing the RIT-T would take significant time, which would compromise the reliability of supply to customers in the North West Slopes area and ultimately likely cost all NSW electricity customers more in the long-run.

We note that the Rules regarding a 'material change in circumstances', and the ability to include 'reopening triggers'[10] in a PACR have recently been considered by the Australian Energy Market Commission.[11] The final rule requires RIT-T proponents of projects with an estimated cost of more than $100 million to develop reopening triggers that clearly indicate whether there has subsequently been a material change in circumstances following completion of the RIT-T.[12] While the new rule requirements do not apply to this RIT-T, consistent with the final rule made, we consider the events above to constitute two elements of an effective reopening trigger for this RIT-T.

We will update stakeholders when we consider that the network support agreement for one of these options is sufficiently certain, or at the point we determine there has been a material change in circumstances and that the investment should be progressed as a solely network option (i.e., Option 3A) (i.e., when we would submit an exemption to the AER from having to reapply the RIT-T).

Our recently submitted Revised Revenue Proposal for the 2023-2028 period includes ex ante augmentation capital expenditure for this project in the forthcoming regulatory period associated with the installation of a new transformer at our Narrabri substation (which is required in 2025/26 irrespective of the demand forecast or preferred option in this PACR). We have also included a nominated pass through event and contingent project to address the risk that no non-network proponents are able to commit to provide the service in the required timeframe, as well as a separate contingent project covering potentially upgrading the existing transmission lines in the area due to future demand growth becoming committed (in particular the Narrabri Gas Project). More information on our 2023-28 Revised Revenue Proposal can be found here.

Further details in relation to this project can be obtained from regulatory.consultation@transgrid.com.au. In the subject field, please reference 'North West Slopes Area reliability project.'

10 We note that what was originally referred to as 'decision rules' at the time of the initial PACR has been relabelled as 'reopening triggers' by the AEMC to differentiate this approach from the decision rules AEMO uses for the ISP. See AEMC, *National Electricity Amendment (Material Change in Network Infrastructure Project Costs) Rule*, Rule Determination, 27 October 2022, p. 9.

11 AEMC, *Transmission Planning and Investment Review*, Consultation Paper, 19 August 2021, p. 54.

12 AEMC, *National Electricity Amendment (Material Change in Network Infrastructure Project Costs) Rule*, Rule Determination, 27 October 2022, p. ii.

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Contents

1. Introduction

We have applied the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining reliable supply to the North West Slopes area of northern New South Wales (NSW). This PACR represents the final stage in the RIT-T process and follows the Project Assessment Draft Report (PADR) released on 18 February 2022. An initial Project Assessment Conclusions Report (PACR) was released for this RIT-T on 30 June 2022 (referred to throughout this document as the 'initial PACR'). This PACR is an amended version of that report.

This amended PACR replaces the initial PACR in light of the dispute raised

On 1 August 2022, the Australian Energy Regulator (AER) received a dispute notice from the Public Interest Advocacy Centre (PIAC), contending that Transgrid may have incorrectly applied the RIT-T in the initial PACR.

On 29 November 2022, the AER released its determination on the dispute and has required Transgrid to amend the initial PACR by 1 February 2023. Specifically, the AER determination requires Transgrid to amend the PACR to:[13]

- include scenarios from the 2021 Inputs, Assumptions and Scenarios Report (IASR) and only use different scenarios where Transgrid can provide demonstrable reasons for that approach;
- demonstrate if alternate scenarios are reasonable such that a reasonable range of plausible states of the world is generated;
- include a common discount rate across all scenarios in the updated cost benefit analysis based on the discount rate in AEMO's most recent IASR, or otherwise provide demonstrable reasons for why a variation from this value is necessary; and
- include an updated cost benefit analysis, including updated sensitivity analysis, for each credible option for each reasonable scenario and its impact on the ranking of the credible options assessed in the PACR.

The AER determination recommended that the amended PACR include sensitivity analysis associated with varying the estimated capital costs of the credible options and the discount rate. It also recommended that the amended PACR include information to enable interested parties to further understand the calculation of the VCR values, the methodology used to estimate capital costs and the basis for including forecast spot loads across the scenarios.

This amended PACR therefore updates the assessment and PACR in-line with the AER dispute determination. The amended PACR only varies from the initial PACR to the extent necessary to reflect the changes made to the scenario assumptions, the revised results and to provide the additional information requested by the AER. We have engaged with the AER on the approach for amending the PACR and consider that this document fully aligns with the direction provided in the determination and subsequent discussions.

As is set out in our 2022 Transmission Annual Planning Report (TAPR), the latest forecasts indicate that electricity demand is expected to increase substantially in the North West Slopes area going forward.[14] This is mainly due to a number of substantial industrial loads that are anticipated to connect, as well as underlying general load growth in Narrabri and Gunnedah.

[13] AER, *Decision: North West Slopes and Bathurst, Orange and Parkes Determination on dispute - Application of the regulatory investment test for transmission*, November 2022, pp. 31-32.
[14] Transgrid, *Transmission annual planning report*, 2022, p 48.

Our power system studies forecast that the expected load growth will reach voltage stability and thermal limits in the next few years on the 132 kV supply network in the North West Slopes area if action is not taken.

Schedule 5.1.4 of the National Electricity Rules (NER) requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage.[15] The NER also requires the power system to be operated in a satisfactory operating state, which requires voltages to be maintained within these levels, both in normal operation and following any credible contingency event.[16]

We have undertaken planning studies that show that the current North West Slopes network will not be capable of supplying the combined increases in load in the area without breaching the NER requirements and that voltage-limited constraints will have to be applied in the 132 kV supply network if action is not taken, leading to substantial levels of unserved energy to end customers. Specifically, we forecast significant under-voltage in this region of our network if action is not taken.

Moreover, in addition to the voltage constraints identified, our planning studies show that the increased demand will also lead to thermal constraints going forward, particularly during times of low renewable generation dispatch in the region.

This RIT-T has therefore examined various network and non-network options for relieving these constraints going forward to ensure compliance with the requirements of the NER and provide the greatest net benefit to the market.

1.1. Purpose

The purpose of this PACR is to:

- identify and confirm the market benefits expected from the various options for relieving the identified constraints going forward to ensure compliance with the requirements of the NER and provide the greatest net benefit to the market over the long-term;
- summarise the submissions received on the PADR 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;
- 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.

[15] These levels are specified in Clause S5.1a.4.
[16] These requirements are set out in Clauses 4.2.6, 4.2.4 and 4.2.2(b) of the NER. The requirement for secure operation of the power system in Clause 4.2.4 requires the power system to be in a satisfactory operating state following any credible contingency event, that is, to maintain voltage within 10 per cent of normal voltage following the first credible contingency event.

A supplementary market modelling report was published on our website alongside the initial PACR, and remains relevant to this amended PACR. Detailed cost benefit results are included as a spreadsheet appendix accompanying this amended PACR.

The credible options outlined in this PACR have been developed as part of our long-term planning for the area and each involves a series of investments over the next twenty years. This RIT-T assesses all stages of these options in order to identify the most efficient series of investments to meet network needs over the long-term.

1.2. Further information and next steps

This amended PACR represents the final stage in the RIT-T process, and follows the AER's determination on the dispute lodged in response to the initial PACR.

The preferred option identified in this PACR remains the same as that identified in the initial PACR and involves the use of Battery Energy Storage Systems (BESS) at the Gunnedah 132 kV substation as a non-network solution and the installation of a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation in the near-term. It also involves rebuilding of the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit and upgrading the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA over the longer-term, depending on outturn demand forecasts.

The proposals of two separate third party BESS proponents have been found to be ranked effectively equal in the PACR assessment and ahead of the preferred network option (Option 3A). The proposal of the third BESS proponent has been found to deliver lower net benefits than these two options and effectively be ranked equally with Option 3A.

We will now enter into a competitive procurement process and commercial negotiations with non-network proponents for a network support contract and seek to put in place a contract with one of these parties. The specific details of these BESS proposals have not been presented in this PACR to preserve the confidentiality requested by the proponents.

Progression of a non-network option will require the successful conclusion of a binding network support agreement between Transgrid and a BESS proponent that is acceptable to the AER. If this does not occur then we consider that the next highest ranked option, Option 3A, is to be considered the preferred option under this RIT-T.

We will update stakeholders when we consider that the network support agreement for one of these options is sufficiently certain, or at the point we determine there has been a material change in circumstances and that Option 3A should instead be progressed (i.e., when we would submit an exemption to the AER from having to reapply the RIT-T).

Our recently submitted Revised Revenue Proposal for the 2023-2028 period includes ex ante augmentation capital expenditure for this project in the forthcoming regulatory period associated with the installation of a new transformer at our Narrabri substation (which is required in 2025/26 irrespective of the demand forecast or preferred option in this PACR). We have also included a nominated pass through event and contingent project to address the risk that no non-network proponents are able to commit to provide the service in the required timeframe, as well as a separate contingent project covering potentially upgrading the existing transmission lines in the area due to future demand growth becoming committed (in particular the Narrabri Gas Project). More information on our 2023-28 Revised Revenue Proposal can be found here.

Further details in relation to this project can be obtained from regulatory.consultation@transgrid.com.au. In the subject field, please reference 'North West Slopes Area reliability project.'

2. Developments since the PADR

This section discusses the 'identified need' for this RIT-T, before outlining the key developments that have occurred since the PADR was released in February 2022. More information on the current network area is provided in Appendix B.

We note that this amended PACR does not reflect any further changes to the assumptions since the initial PACR, other than those made as a consequence of the AER's dispute determination. This is consistent with the AER's view that, as a principle, they expect Transgrid to apply the same information that was available at the time of the PACR, unless Transgrid considers that there has been a material change in circumstances as defined in the NER.

While this section remains largely the same as the corresponding section in the initial PACR, we have included additional information on the basis for the spot load forecasts below, as well as in Appendix C, to improve transparency, in-line with the AER dispute determination.

2.1. Summary of the 'identified need'

Schedule 5.1.4 of the NER requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage.[17] The NER also requires the power system to be operated in a satisfactory operating state, which requires voltages to be maintained within these levels, both in normal operation and following any credible contingency event.[18]

We have undertaken planning studies that show that the current North West Slopes network will not be capable of supplying the forecast increases in load in the area without breaching the NER requirements and that voltage-limited constraints will have to be applied in the 132 kV supply network if action is not taken, leading to substantial levels of unserved energy to end customers. Specifically, we forecast significant under-voltage in this region of our network if action is not taken.

Moreover, in addition to the voltage constraints identified, our planning studies show that the increased demand will also lead to thermal constraints, particularly during times of low renewable generation dispatch in the region.

Demand forecasts for the area have been updated since the PADR, due to both an update from Essential Energy in terms of load in their network as well as more information being provided by key spot loads in the area regarding the status of their developments (as outlined in section 2.3).

If the longer-term constraints associated with the load growth are unresolved, it could result in the interruption of a significant amount of electricity supply under both normal and contingency conditions due to voltage and thermal limitations in the area.

This RIT-T has therefore assessed options to ensure the above NER requirements continue to be met in the North West Slopes area in light of the forecast demand increases. We consider this a 'reliability corrective action' under the RIT-T as the proposed investment is for the purpose of meeting externally-imposed regulatory obligations and service standards, i.e., Schedule 5.1.4 of the NER.

17 These levels are specified in Clause S5.1a.4.
18 These requirements are set out in Clauses 4.2.6, 4.2.4 and 4.2.2(b) of the NER. The requirement for secure operation of the power system in Clause 4.2.4 requires the power system to be in a satisfactory operating state following any credible contingency event, that is, to maintain voltage within 10 per cent of normal voltage following the first credible contingency event.

In addition, some of the credible options assessed will also affect the wholesale electricity market through the use of grid-connected storage. Both the benefits from the provision of reliable supply to North West Slopes and wider wholesale market benefits have been estimated as part of this PACR (consistent with the earlier PADR).

2.2. Wholesale market benefits expected from the use of non-network solutions

Four of the credible options assessed in this PACR involve the use of BESS, three of which have been proposed by third party proponents of these solutions. These components are expected to be able to assist with providing reactive support in the short-term but could also use a portion of their capacity to dispatch to the wholesale market (as outlined in section 2.3.4), offsetting more costly generation that would otherwise be called to operate, and thus provide wider wholesale market benefits in addition to the avoided unserved energy that all options provide.

These wider benefits have been estimated by way of wholesale market modelling conducted by EY and are found to be made up primarily of avoided and deferred capital costs of new generation and storage. The wholesale market modelling remains applicable to this amended PACR and has therefore not been updated since the initial PACR (as set out in section 2.3.3 below).

While the other credible network options (i.e., the solely network options) will provide additional system strength to the North West Slopes region, we do not consider there to be material wholesale market benefits associated with these options. Specifically, while this additional capacity may affect the investment decisions of future local renewable generators on the 132 kV network, upstream 330 kV network constraints outside of this RIT-T (particularly south of Tamworth) mean that any new generation is not expected to displace the output of generation elsewhere and so there is not expected to be any material wider wholesale market impacts between the options and the base case. As a consequence, these credible options do not address network constraints between competing generators and so will not have an impact on generation dispatch outcomes and the wholesale electricity market.

None of the options are expected to add to, or takeaway from, any wholesale market benefits from future expansions of QNI over the longer term (e.g., ‘QNI Connect’ referred to in the 2022 ISP). These future upgrades of QNI are expected to be 330 kV and will not tie into the 132 kV network in the North West Slopes area (despite likely passing nearby).

2.3. Developments since the PADR was released in February 2022

A number of key developments have occurred since the PADR was released, which impact the analysis in this RIT-T. In particular:

- the demand forecasts have been updated based on additional information provided by proponents of new or expanded industrial spot loads, as well as updated information on general load growth from Essential Energy;
- our forecasts of when voltage and thermal limits are expected to be breached have been updated in light of the revised demand forecasts;
- the wholesale market modelling has been updated to reflect the assumptions underpinning AEMO’s 2022 Integrated System Plan (ISP) and is now focused on the Step Change, Progressive Change and Hydrogen Superpower scenarios (the scenario weightings have also been updated to be consistent with the 2022 ISP);

- there have been a number of updates to the non-network options that were assessed in the PADR (Option 5A and Option 5B), including to reflect new information provided by the proponents;
- a new non-network option (Option 5C) has been included in the assessment following a submission to the PADR;
- there has been an update to the assumptions regarding how BESS components are likely to be able to trade in the wholesale market, based on further analysis of the amount of storage that would be required to be reserved to provide network support; and
- there have been a number of updates to the network options, including revised costs and reactive support sizing.

Each of these developments is discussed in the sections below.

2.3.1. Demand forecasts have been updated since the PADR

Demand forecasts are a key driver of the identified need for this RIT-T and are expected to increase significantly in the North West Slopes power system due to both underlying general load growth as well as specific spot load developments coming online. The PACR has considered two demand forecasts (the central and low forecasts) representing different assumed quantities, timings and locations for key loads.

The key changes in the PACR demand forecasts compared to the PADR are:

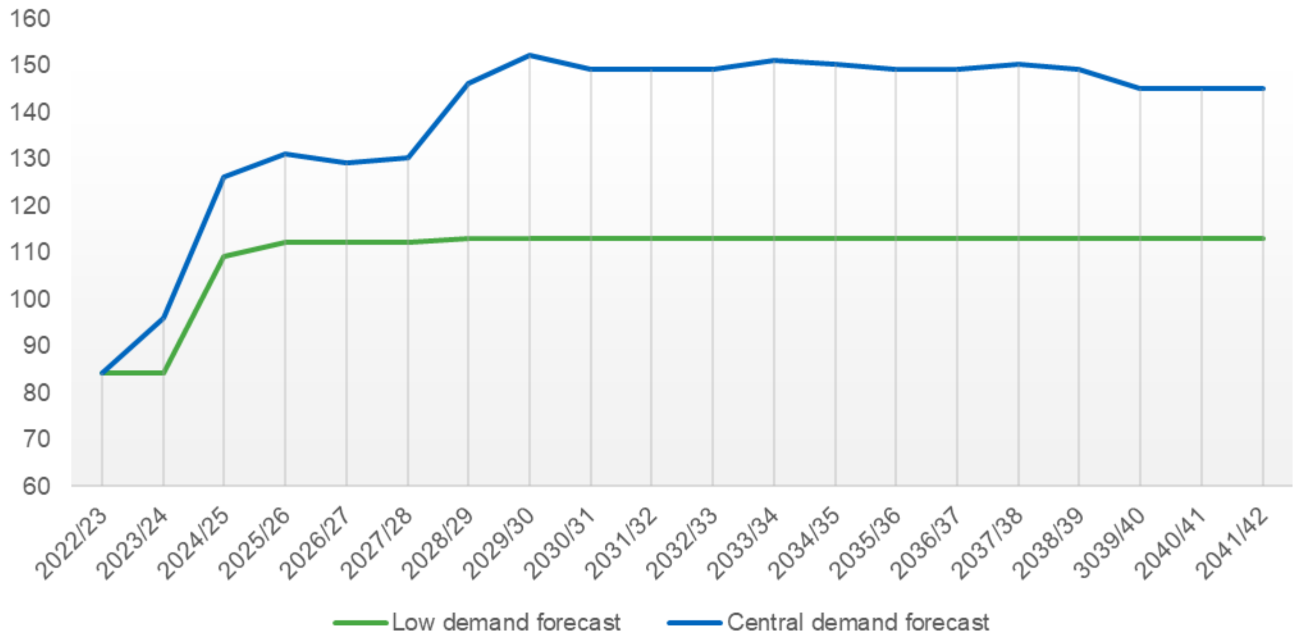
- Essential Energy providing revised general demand forecasts for the region as part of an annual update;
- the inclusion of the Narrabri Coal expansion in the central demand forecast (this is a new spot load that was not included in Essential Energy's demand forecasts at the time of the PADR); and
- a one year delay to the commencement of the expansion of the existing Vickery Coal Mine (VCM).

The last two changes above reflect additional information provided by proponents following the PADR.

There has been no change to the Narrabri Gas Project load reflected in the demand forecasts since the PADR.

Figure 2.1 presents the updated peak demand forecasts used in the PACR assessment.

Figure 2.1: Peak demand forecasts for the North West Slopes area



As in the PADR, the PACR does not include a high demand forecast since no additional loads are considered sufficiently committed to include at this stage.[19] The Hydrogen Superpower scenario investigated in this PACR therefore applies the central demand forecast (as outlined in section 5.1 below).

The key spot loads are reflected in the demand forecasts used in this PACR as follows:

- Low demand forecast:
  - VCM and the Narrabri Coal expansion do not connect; and
  - only Stage 1 of the Narrabri Gas Project is assumed to connect.[20]
- Central forecast:
  - assumes that VCM, the Narrabri Coal expansion, and the Narrabri Gas Project connect; and
  - assumes the full forecast for the Narrabri Gas Project (Stages 1 and 2).

The demand forecasts therefore reflect the various stages of potential development for the key loads and allow the PACR to assess how the net benefit of the options considered varies, depending on differing assumptions around the progression of later development stages.

The demand forecasts have been developed following an extensive information gathering exercise from potential load proponents. Specifically, we asked each potential proponent to provide evidence of whether it considers the load meets the specific criteria under the RIT-T for a project to be considered 'anticipated' or 'committed'.

We note that the **low demand forecast** includes 29 MW of spot load considered 'anticipated', which comprises 26 per cent of the total load included in this forecast. This anticipated spot load has been

[19] As noted in the PADR, the confidential mining load that drove the high demand forecast in the PSCR (and was the only difference between the central and high demand forecasts at that point in time) is no longer expected to connect.

[20] The development of the gas pipeline linking the Narrabri Gas Project to the existing Moomba to Sydney Pipeline could affect the later stages of the Narrabri Gas Project, See Appendix B for detail on the potential gas pipeline linking the Narrabri Gas Project to the existing Moomba to Sydney Pipeline.

included in the low forecast as we have judged it to have a high enough probability of occurring, given that there are a number of anticipated spot loads in the area. As is noted above, the anticipated spot load in this forecast reflects Stage 1 (only) of the Narrabri Gas Project.

The **central demand forecast** varies from the low demand forecast by the inclusion of three additional anticipated spot loads, as well as Stage 2 of the Narrabri Gas Project.

Appendix C provides additional detail on the various key loads and how they have been included in the assessment (while some details have had to be redacted due to confidentiality reasons, the full detail of this table has been provided to the AER in-confidence).

We also engaged GHD to independently confirm the reasonableness of the demand forecasts. GHD's report has been published alongside this amended PACR.

Essential Energy also provided revised general demand forecasts for the region as part of an annual update. However, this has only had a minor impact on the load forecasts at Gunnedah and Narrabri, both of which have increased slightly (and have been reflected in our 2022 TAPR).

2.3.2. Forecast of when voltage and thermal limits are expected to be breached if action is not taken

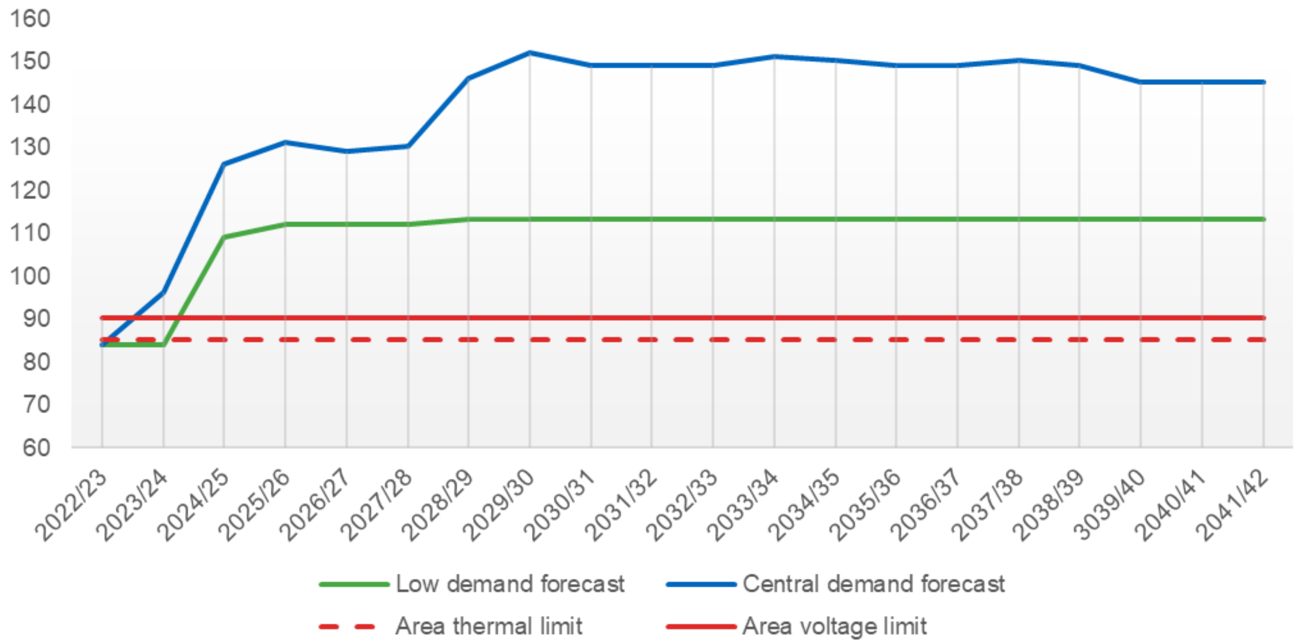
The changes in the load forecasts have not had an impact on when the forecast voltage and thermal limits are expected to be breached if action is not taken compared to what was presented in the PADR.

Specifically, our system studies continue to show that the available capacity in the North West Slopes area is limited following connection of key loads by:

- thermal constraints on line 969 (Tamworth to Gunnedah) under system normal conditions; and
- voltage stability constraints between Gunnedah and Narrabri for a contingent outage of line 969 or 968 (Tamworth to Narrabri).

Figure 2.2 shows the updated voltage limits for the North West Slopes area considering the maximum demand that can be supplied without resulting in network voltages below 0.9 pu, under system normal and under (N-1) contingency conditions, along with the thermal limit due to the increased demand.

Figure 2.2: Peak demand forecast with voltage and thermal limits



The voltage stability constraint occurs for a trip of line 969, and is expected by 2024/25 and 2025/26 under the central and low demand forecasts, respectively.

The thermal constraint on line 969 due to the inclusion of Stage 1 of the Narrabri Gas Project in 2025/26 can occur during system normal conditions or a contingent outage of line 968 under both demand forecasts when there is limited generation in service in the area to offset the load. It can also occur during system normal conditions from 2029/2030 onwards under the central forecast following the inclusion of Stage 2 of the Narrabri Gas Project, even with more generation in service.

The thermal constraint is expected to occur from the inclusion of VCM in 2024/25 along with the Narrabri Coal load growth but can also be temporarily managed by operational measures until Stage 1 of the Narrabri Gas Project comes online.

Under the central demand forecast, the voltage constraints are expected to worsen from 2025/26 onwards. Voltages at Narrabri and Gunnedah would be further outside of the planning criteria set out in Schedule 5.1.4 of the NER for an outage of one of the 132 kV transmission lines supplying Narrabri and Gunnedah from Tamworth (lines 968 or 969).

If action is not taken, voltages in the area will drop to unsustainable levels and voltage collapse could occur in the region following a contingency on line 969 due to insufficient dynamic reactive support in the region under both demand forecasts. This voltage collapse could lead to significant amounts of load being shed throughout the North West Slopes area.

Under both demand forecasts outlined in this PACR, the load increase at the Narrabri substation leads to the firm supply capacity for the transformers at this location being exceeded. This will result in the IPART reliability standard not being met.

2.3.3. The wholesale market modelling has been updated from the PADR to explicitly model the three key 2022 ISP scenarios

The credible options in the PADR were assessed using a set of market modelling assumptions that were largely based on the 'Progressive Change' scenario identified by AEMO in the draft 2022 ISP (released in December 2021).[21]

The wholesale market modelling has been updated in the PACR to:

- explicitly model each of the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2022 ISP, adopting the 2021 IASR assumptions; and
- align with the optimal development path and assumptions in the draft 2022 ISP.

The wholesale market modelling has not been updated since the initial PACR, consistent with the direction from the AER. Specifically, the AER has advised that in amending the PACR we are to apply the same information that was available at the time of the PACR, unless we consider that there has been a material change in circumstances (as defined in the NER). We do not consider that the limited differences in the optimal development path and assumptions between the draft and final 2022 ISPs are sufficient enough to materially affect the wholesale market benefits for this RIT-T (and we note that wholesale market benefits are relatively small for the options considered, making up only between zero and 12 per cent of the gross market benefits for the options assessed).

Section 6.3 provides further detail on how the market modelling has been undertaken for this PACR, while Appendix F provides an overview of the market simulation exercise undertaken and the key assumptions drawn upon. A separate market modelling report prepared by EY was released alongside the initial PACR, and remains relevant to this amended PACR.

We note that there were two announcements made between the draft 2022 ISP and the initial PACR regarding the early closure of coal-fired power stations in the NEM. Specifically:

- AGL announced in February 2022 that the Loy Yang A Power Station in Victoria and Bayswater Power Station in NSW will close by at least 2045 and 2033, respectively (three years early than previously indicated);[22] and
- Origin Energy submitted a notice to AEMO in February 2022 for the potential early retirement of Eraring Power Station in August 2025 (seven years early than previously indicated).[23]

The wholesale market modelling included as part of this PACR (and the initial PACR) takes account of these dates (and draws directly on the latest AEMO generator information database available at the time of the initial PACR).

We note that on 29 September 2022, AGL updated its expected closure date for the Loy Yang A Power Station to the end of the 2035 financial year (up to 10 years earlier than previously planned).[24] However, we do not consider this announcement to be material to the overall assessment due to the market

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21 We initially modelled the market benefits for the PADR using AEMO's 'steady progress' 2022 ISP scenario, which AEMO noted in the 2021 IASR is 'similar conceptually to the 2020 central scenario'. However, the draft 2022 ISP released on 10 December 2021 stated that the steady progress scenario is no longer relevant, given Australia's commitment to net zero emissions by 2050. We therefore updated the market modelling for the PADR over December 2021 and January 2022 to be based on the Progressive Change scenario (time would not permit updating to the Step Change scenario).

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

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

24 AGL Energy, *A clear pathway for a responsible energy transition,* p. 1. See: https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/how-we-source-energy/loy-yang-power-station/220930-ly-transition.pdf

modelling retiring power stations according to least-system-cost, as opposed to at set dates,[25] and the significance of the wholesale market benefits in the overall assessment.[26]

2.3.4. Updates to the non-network options (Option 5A and 5B)

We have worked with the proponents of Option 5A and Option 5B (both of which involve network support provided by BESS) to carefully review the proposed timing and cost of each solution. This has resulted in:

- the timing of Option 5A being brought forward by six months from the PADR;
- minor revisions to the cost of Option 5A and Option 5B; and
- elements of the non-network options being resized and re-scoped by proponents.

These options are not considered to be a long-term standalone solution and, instead, will defer or avoid some of the network investment that would otherwise be required.

In addition, we have conducted an assessment of the technical capacity all non-network options assessed in this PACR (including Option 5C, outlined below) and now consider that the non-network options will be able to address the load growth's thermal and voltage constraints sufficiently until the network between Tamworth and Gunnedah is strengthened in 2029/30.

2.3.5. A new non-network option has been included in the assessment (Option 5C)

In response to a submission made in response to the PADR, a new non-network option has been included in the PACR analysis, 'Option 5C'.

Option 5C uses a BESS to provide a network support service, in a similar way to Option 5A and Option 5B (but with different capacities and/or locations). The details of Option 5C have not been presented in this PACR to preserve the requested confidentiality by the proponent.

As with Option 5A and Option 5B, this option is not considered to be a long-term standalone solution and, instead, will defer or avoid some of the network investment that would otherwise be required. Further information regarding Option 5C is provided in section 4.4 below.

2.3.6. Updated assumptions regarding how BESS components can trade in market services

We have further assessed the ability of BESS components to use their capacity to participate in market services outside of their network support commitments. This covers the three non-network-provided BESS options (i.e. Options 5A, 5B and 5C).

While the PADR adopted a simplifying assumption that these BESS components could use their full capacity to participate in the market,[27] we now assume differing abilities to participate in market services for the BESS components across both any particular year and over time (and, specifically, before and after the network component of these options is commissioned in 2029/30). These assumptions reflect best estimates at this point in time and the specific commercial and operational requirements for BESS

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[25] Specifically, the wholesale market modelling forecasts that Loy Yang A will be retired ahead of 2035 in the Step Change and Hydrogen Superpower scenarios. While the modelling finds that Loy Yang A continues its operation until the early 2040s under the Progressive Change scenario, we do not consider this material to the overall assessment given it relates to one generator, under one scenario (with a weight of 30 per cent), and the wholesale market benefits only make up a small proportion of the total estimated net benefits (see next footnote).

[26] Specifically, the wholesale market benefits are relatively small for the options considered, making up only between zero and 12 per cent of the gross market benefits for the options assessed.

[27] This assumption was made at the time of the PADR as a simplifying assumption, and one in favour of the non-network options, in order to test whether these options were expected to be preferred. The PADR outlined that we would be working with proponents to revise this assumption ahead of the PACR (see section 6.4 of the PADR).

components of non-network options will be refined during the commercial negotiations and procurement process following the completion of the RIT-T.

The updated assumptions regarding the capacity to participate market services can be summarised as follows:

- before the network component[28] is commissioned and before the Narrabri Gas Project comes online:
    - full battery capacity is available throughout the year except for in Summer (mid-November to mid-March), where a minor quantity of battery capacity may be required to be reserved.
- before the network component is commissioned but after the Narrabri Gas Project comes online:
    - full battery capacity is available throughout the year except for in Summer and June, where either no battery capacity is available or a quantity of battery capacity is required to be reserved.
- after the network component is commissioned:
    - full battery capacity is available throughout the year except for in Summer, where a minor quantity of battery capacity is required to be reserved.

In addition, following the more detailed review of the BESS components' ability to participate outside of their network support commitments, the network owned BESS option (Option 3B) is now also assumed to be able to participate in market services and generate wider wholesale market benefits. However, we note that this is assumed able to occur only after the commissioning of the network components in 2029/30 and is only able to occur outside of the summer peak period.[29]

The specific energy and capacity that is assumed able to trade in the market for each option has not been presented in this PACR to preserve the confidentiality requested by proponents of these solutions.

2.3.7. Updates to the network options

We have reviewed and, in some cases, updated the timing of the network components of each credible option in light of the updated demand forecasts.

Capital costs for the network options have been revised since the PADR to reflect the change in size of some elements, as well as to reflect current market trends and risks, drawing on the experience of recent projects. The capital costs in this amended PACR remain the same as in the initial PACR. We have however presented a sensitivity with increased costs for the network component of the options, to reflect our latest unit rates, in line with our revised Regulatory Proposal.

The cost of the BESS component in Option 3B has also been updated since the PADR to reflect a proposal by a third-party in response to the PADR.

[28] Specifically, rebuilding the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit and upgrading the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA.

[29] Consistent with the current transmission ring-fencing guidelines, we have implicitly assumed that we would lease out the spare battery capacity to a third party to provide these contestable services. However, we note that the AER is currently reviewing the transmission ring-fencing guidelines and, specifically, in the case of TNSP-owned batteries, whether the TNSPs should be able to lease excess capacity to third parties. The AER's draft transmission ringfencing guidelines propose not to permit TNSPs to lease spare battery capacity, unless they have obtained a waiver from the AER (see: AER, *Electricity Transmission Ring-fencing Guideline*, Explanatory Statement – Version 4, Draft, p. viii). However this position is currently being consulted on. The ability of this option to generate these wider wholesale market benefits is therefore subject to the outcome of this review process.

3. Consultation on the PADR

The PADR was released in February 2022 and we subsequently received submissions from seven parties, one of whom submitted two separate submissions.

The two submissions from the same party (Whitehaven Coal) and one other submission (from PIAC) are publicly available and have been published on our website.[30] The remainder of the submitters explicitly requested confidentiality and so the details of these submissions have not been included in this PACR, or on our website.

The main topics that emerged in the submissions were:

- a new non-network option;
- further details regarding an earlier proposed non-network option;
- uncertainty around the demand forecasts;
- a proposal for an alternate conductor technology, that could reduce the network option costs; and
- the appropriateness of the 'high benefits' scenario in PADR.

In addition, one of the confidential submitters proposed the use of an alternate conductor technology. We have assessed this option thoroughly as part of preparing the PACR and works for the line 969 double-circuit rebuild, and the 9UH line uprating, now reflect the use (and costs) of this alternate conductor technology proposed in response to the PADR.

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

3.1. Uncertainty around the demand forecasts

PIAC expressed concerns over demand forecasts being treated as commercial-in-confidence.[31] PIAC also expressed concern regarding using demand forecasts based on regional growth plans, such as the Narrabri SAP, suggesting they are largely aspirational and include targets that are rarely met within intended timeframes.[32]

We understand that there are valid commercial reasons for demand forecasts being kept confidential in RIT-T processes. We note that some of the key loads have made their forecasts public as part of their PADR submission, e.g., Whitehaven Coal's Narrabri Coal Stage 3 Expansion Project. In addition, while not released publicly, the detail regarding all load forecasts has been shared in-confidence with the AER in its role of overseeing the RIT-T and ensuring the efficiency of any ultimately proposed expenditure.

In preparing this PACR, we have engaged further with load proponents on the commitment status for key potential loads. Specifically, we have sought to corroborate the forecasts provided by proponents through having them provide additional information as to how each load is considered to meet the RIT-T criteria for being considered 'committed' or 'anticipated'. Appendix C provides additional detail on the various key

30 https://www.transgrid.com.au/projects-innovation/north-west-slopes-area-supply
31 PIAC, p. 1.
32 PIAC, p. 1.

loads and how they have been included in the assessment (while some details have had to be redacted due to confidentiality reasons), in response to the AER's dispute determination.

Whitehaven Coal provided confirmation regarding the intent to proceed with the Narrabri Coal Stage 3 expansion project (which received approval from the Independent Planning Commission on 1 April 2022)[33] and the Vickery expansion project (which has received state and federal approval).[34] Section 2.3.1 above outlines how these two loads have been reflected in the demand forecasts for this PACR.

3.2. Estimating the market benefits of the options

PIAC expressed a view that the high benefits scenario from the PADR should not be included in the analysis due to unrealistic assumptions.[35] PIAC recommended a 'more realistic' approach of applying 50 per cent weighting to each of the central and low net economic benefits scenarios (and removing the high scenario).[36]

We note that the purpose of using a high benefits (and low benefits) scenario is to test the rankings of options against an extreme bound of plausible economic benefits. Specifically, the three scenarios assessed in the initial PACR reflect combinations of assumptions that are expected to affect the ranking of the credible options, including the expected wholesale market benefits, in order to comprehensively test the range of net benefits that can be expected from the credible options.

We note that the high benefits and low benefits scenarios were largely symmetric in terms of the assumptions drawn upon and we consider that removing one (as PIAC suggested) would bias the analysis.

In light of the AER dispute determination, we have amended how the scenarios are constructed and in this amended PACR we now assess the options across three scenarios consistent with the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2021 IASR. Section 5.1 outlines how the scenarios have been updated from the initial PACR.

We have weighted each of the scenarios for this RIT-T based on the 2022 ISP weightings for the underlying wholesale market scenarios. 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 (as outlined in section 5.2). We have also carefully considered the results in each scenario in section 7 and investigated a sensitivity that applies the scenario weights from the PADR (see section 7.5.5).

33 Whitehaven Coal, p. 1 (Narrabri Coal submission).
34 Whitehaven Coal, p. 1 (Vickery expansion project submission).
35 PIAC, p. 1.
36 PIAC, p. 2.

4. Credible options assessed

This PACR assesses both network and non-network options.

Each of the credible network options requires the installation of a third 60 MVA 132/66 kV transformer at Narrabri due to the firm supply capacity of the existing transformers at this location being exceeded under both demand forecasts and to ensure the reliability standard set by IPART is met for Narrabri in the short-term.

Aside from the new 132/66 kV transformer at Narrabri, the credible network options assessed differ in the near-term by where, how and when new capacity is added to the North West Slopes region. In particular, there are three broad types of credible option assessed that centre on:

- uprating the existing line 969 from Tamworth to Gunnedah (Option 1A and Option 1B);
- installing new single or double circuit transmission lines between Tamworth and Gunnedah (Option 2A, Option 2B, Option 2C and Option 2D); and
- rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line (Option 3A, Option 3B and Option 3C).

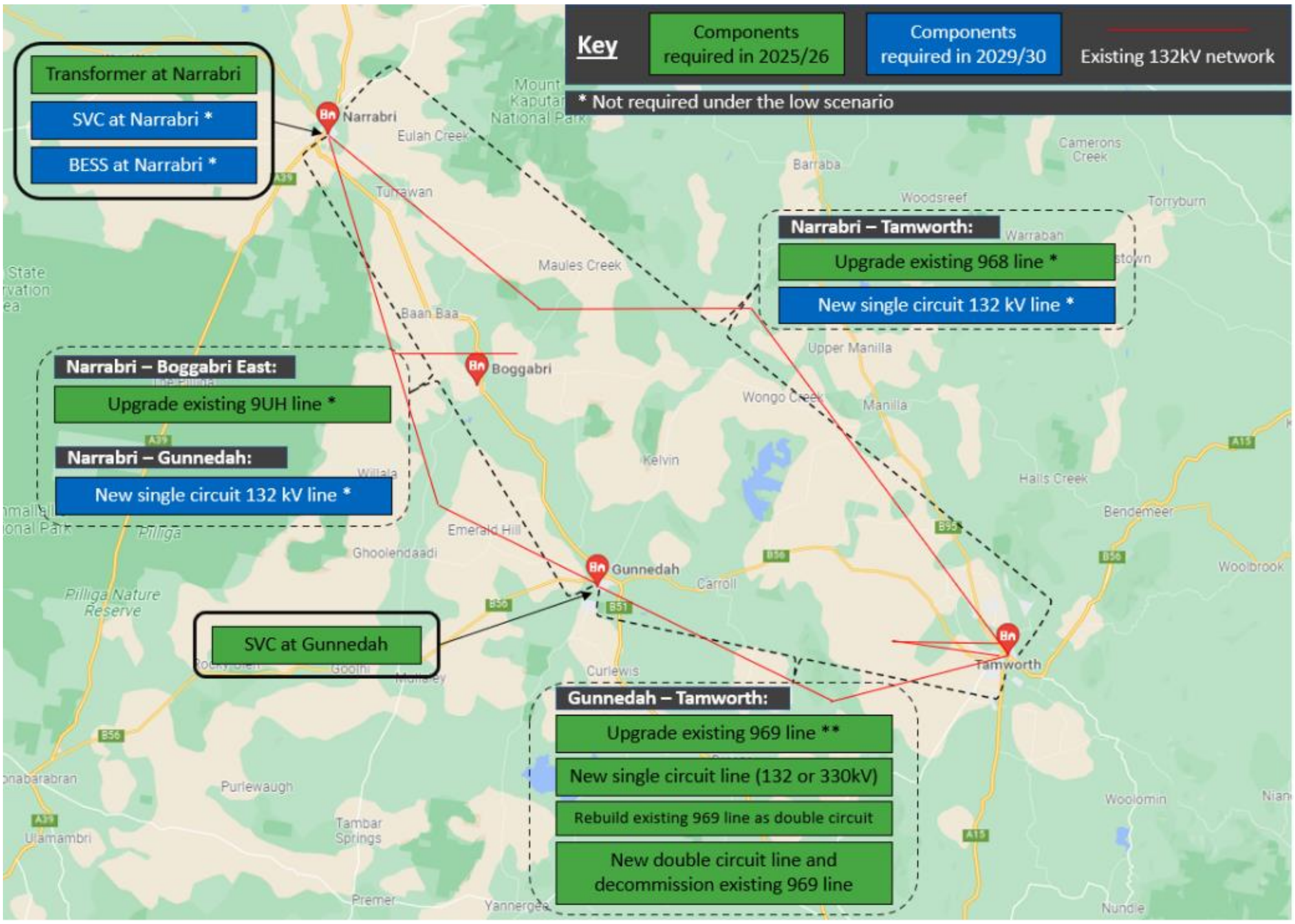
Most credible options include the provision of dynamic reactive support at Narrabri provided by an SVC or grid-scale BESS. Two options (Option 2C and Option 3C) involve a new transmission line between Gunnedah and Narrabri as an alternative to dynamic reactive support and the upgrade to the 9UH line.

Figure 4.1 below illustrates the various components that make up the credible network options. Specifically, it shows the technology and location of the components that can assist with both the short-term and longer-term voltage support required. While the credible options reflect different combinations of these components, we note that not all components can be coupled together to form credible options (and the earlier components can impact the choice of the later component(s)).

All locations shown in the figure below, and all figures in this section, have been included purely for illustrative purposes and are not intended to denote specific locations or line routes.

Importantly, each of the options involves two potential stages of investment, depending on the option and scenario. These are shown in the figure below as the components required in 2025/26 (in green) and the components required in 2029/30 (in blue). The individual option sections below detail the specific timing assumed for each stage of each option under the two demand forecasts.

Figure 4.1: Various components the credible network options involve



*** While the upgrade of the 969 line between Gunnedah and Tamworth to 160 MVA is required under the low and central demand forecasts for Options 1A and 1B, it is only required under the central demand forecast and to 135 MVA for Options 2A, 2B, 2D and 4.*

While there have been no material changes to the network options since the PADR, the non-network options considered in the PACR assessment have been refined to reflect:

- submissions to the PADR, resulting in the timing of Option 5A being brought forward by six months from the PADR, minor revisions to the cost of Option 5A and Option 5B and the inclusion of a third non-network option (Option 5C); and
- elements of the non-network options being resized and rescoped following additional information provided by proponents.

In addition, as outlined in section 4.4, the non-network solutions have been modelled in terms of their ability to efficiently defer or avoid the rebuilding of line 969 as a double-circuit line when the Narrabri Gas Project comes online, which is part of the preferred network option (Option 3A). Non-network options are not able to avoid or defer the need for the initial third transformer required at Narrabri under this option since capacity is required there immediately to ensure the reliability standard set by IPART is met at Narrabri. The non-network options therefore reflect a combination of an initial non-network component and a third Narrabri transformer in all scenarios, followed by a deferred rebuilding of line 969 as a double-circuit line and upgrading the 9UH line between Narrabri and Boggabri North in the Step Change and Hydrogen Superpower scenarios when the Narrabri Gas Project comes online.

Table 4.1 below summarises each of the credible options assessed in the PACR. All options are considered to meet the identified need from a technical, commercial, and project delivery perspective.[37]

While all potential components of each option are shown in Table 4.1, some of the later components are not required over the assessment period for the low demand forecast and are only relevant for the central demand forecast (in the later years of the assessment period). The timing of the initial components for all options has been fixed across the two demand forecasts (since these components effectively need to be committed to now to ensure commissioning in time under the central forecast), while the timing of the later components varies by forecast depending on when they are required (since they do not yet need to be committed to). The individual option sections below detail the specific timing assumed for each component of each option under the two demand forecasts.

While some component costs in Table 4.1 below include land costs and biodiversity offset costs, they have not been broken out separately to contain the table. However, the NPV model released alongside the PACR separates out these elements.

Table 4.1: Summary of the credible options

Option	Description	Estimated capex ($2020/21)
	Uprating the existing line 969 from Tamworth to Gunnedah	
1A	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA	• $51 million
	• Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah substation	• $18 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Upgrade the existing 968 line between Tamworth 330 and Narrabri substations to a rating of at least 160 MVA	• $149 million
	• Install a 132 kV +60 MVAr -20 MVAr SVC at Narrabri	• $20 million
1B	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA	• $51 million
	• Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah substation	• $18 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million

37 As per clause 5.15.2(a) of the NER.

Option	Description	Estimated capex ($2020/21)
	• Build a new 132 kV line between Tamworth 330/132 kV and Narrabri 132/66 kV substations	• $160 million
	New single or double circuit transmission lines between Tamworth and Gunnedah	
2A	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah.	• $73 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $28 million
	• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
2B	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new double circuit 132 kV line between Tamworth 330 kV and Gunnedah, each circuit rated at 160 MVA. Decommission the existing 969 transmission line	• $89 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $28 million
	• Installation of a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
2C	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah	• $73 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Build a new single circuit 132 kV line between Narrabri and Gunnedah	• $106 million
2D	• Install a third 60 MVA 132/66 kV transformer at Narrabri	• $8 million
	• Build a new single circuit 330 kV line between Tamworth 330 kV and Gunnedah operated at 132 kV, rated at least 160 MVA	• $159 million
	• Upgrade the existing 969 line to a rating of 135 MVA	• $51 million
	• Upgrade the 9UH line to a rating of 100 MVA	• $28 million
	• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	• $20 million
	Rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line	
3A	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Install a 132 kV +60 MVAr (capacitive) -20 MVAr (inductive) SVC at Narrabri substation	• $20 million
3B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million

Option	Description	Estimated capex ($2020/21)
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
	• Install a 50 MW (50 MWh) BESS at Narrabri 132 kV	• Confidential
3C	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Build a new single circuit 132 kV line between Narrabri and Gunnedah	• $106 million
Combination of non-network solutions with the top-ranked network option (Option 3A)		
5A	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS at Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
5B	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS near Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million
5C	• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	• $8 million
	• Install a BESS at Gunnedah 132 kV as a network support service	• Confidential
	• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	• $87 million
	• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	• $28 million

Capital costs for the network options have been revised since the PADR to reflect the change in size of some elements, as well as to reflect current market trends and risks, drawing on the experience of recent projects. In addition, works for the line 969 double-circuit rebuild, and the 9UH line uprating, now reflect the use (and costs) of an alternate conductor technology proposed in response to the PADR. Appendix D provides additional detail on the methodology used to estimate capital costs (consistent with the AER dispute determination), including biodiversity offset and land costs,.

All network options are assumed to have annual operating and maintenance costs equal to approximately one per cent of their capital costs (excluding biodiversity offset and land costs).

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

Appendix C provides the indicative ultimate layouts, via line diagrams, for all elements of the options.

4.1. Option 1 – Uprating the existing line 969 from Tamworth to Gunnedah

This option involves uprating the existing line 969 and the two variants test different line augmentations and dynamic reactive support levels at Narrabri and Gunnedah.

The scope of the various elements for Option 1A and Option 1B is shown in Table 4.1 above.

Table 4.2 summarises the optimal assumed timing for each component under the two different demand forecasts investigated.

Table 4.2: Summary of the assumed timing for each component of Option 1A and Option 1B

Component	Expected timing (low)	Expected timing (central)
Option 1A		
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA • Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah Substation	2025/26	2025/26
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2028/29
• Upgrade the existing 968 line between Tamworth 330 and Narrabri substations to a rating of at least 160 MVA	N/A	2027/28
• Install a 132 kV +60 MVAr -20 MVAr SVC at Narrabri	N/A	2029/30
Option 1B		
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA • Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah Substation	2025/26	2025/26
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2026/27
• Build a new 132 kV line between Tamworth 330/132 kV and Narrabri 132/66 kV substations	N/A	2029/30

Figure 4.2 below illustrates the type and location of the key elements for Option 1A and Option 1B.

Figure 4.2: Overview of the key elements in Option 1A and Option 1B

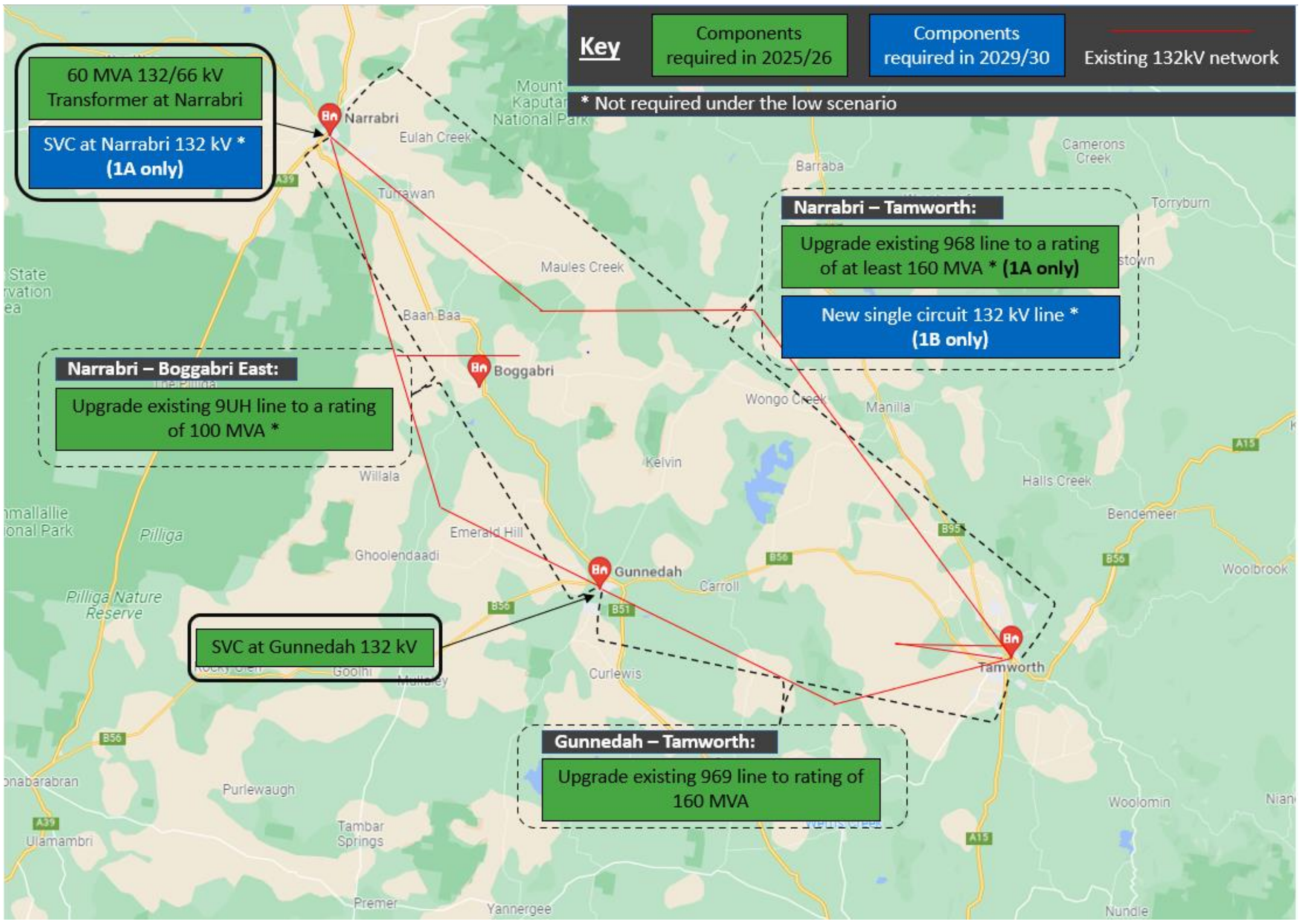


Table 4.3 summarises the expected construction time for each component.

Table 4.3: Summary of the expected construction time for each component of Option 1A and Option 1B

Component	Expected construction time[38]
Option 1A	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA • Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah Substation	36 months
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA • Upgrade the existing 968 line between Tamworth 330 and Narrabri substations to a rating of at least 160 MVA	65 months
• Install a 132 kV +60 MVAr -20 MVAr SVC at Narrabri	37 months

[38] Please note that all expected construction times are presented as beginning from Design Gate 1 (DG1), which would commence approximately 1 month after the PACR.

Option 1B	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Upgrade the existing 969 line between Tamworth 330/132 kV and Gunnedah 132/66 kV substations to a rating of 160 MVA • Install a 132 kV +50 MVAr (capacitive) -20 MVAr (inductive) SVC at Gunnedah Substation	36 months
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	48 months
• Build a new 132 kV line between Tamworth 330/132 kV and Narrabri 132/66 kV substations	69 months

4.2. Option 2 – New single or double circuit transmission lines between Tamworth and Gunnedah

This option involves installing new single or double circuit transmission lines between the Tamworth 330 kV substation and Gunnedah with the variants testing different line augmentations.

The scope of elements for Option 2A, Option 2B, Option 2C and Option 2D is shown in Table 4.1 above.

Table 4.4 summarises the optimal assumed timing for each component under the two different demand forecasts investigated.

Table 4.4: Summary of the assumed timing for each component of Options 2A-2D

Component	Expected timing (low)	Expected timing (central)
Option 2A		
• Install a third 60 MVA 132/66 kV transformer at Narrabri	2025/26	2025/26
• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah.	2028/29	2028/29
• Upgrade the existing 969 line to a rating of 135 MVA	N/A	2027/28
• Upgrade the 9UH line to a rating of 100 MVA	N/A	2028/29
• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	N/A	2029/30
Option 2B		
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Decommission the existing 969 transmission line	2025/26	2025/26
• Build a new double circuit 132 kV line between Tamworth 330 kV and Gunnedah, each circuit rated at 160 MVA	2028/29	2028/29
• Upgrade the 9UH line to a rating of 100 MVA	N/A	2027/28
• Installation of a 132 kV +50 MVAr -20 MVAr SVC at Narrabri.	N/A	2029/30
Option 2C		
• Install a third 60 MVA 132/66 kV transformer at Narrabri	2025/26	2025/26
• Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah	2028/29	2028/29

• Upgrade the existing 969 line to a rating of 135 MVA	N/A	2027/28
• Build a new single circuit 132 kV line between Narrabri and Gunnedah	N/A	2029/30
Option 2D		
• Install a third 60 MVA 132/66 kV transformer at Narrabri	2025/26	2025/26
• Build a new single circuit 330 kV line between Tamworth 330 kV and Gunnedah operated at 132 kV, rated at least 160 MVA	2028/29	2028/29
• Upgrade the existing 969 line to a rating of 135 MVA • Upgrade the 9UH line to a rating of 100 MVA	N/A	2027/28
• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	N/A	2029/30

Figure 4.3 below illustrates the type and location of the key elements for Options 2A-2D.

Figure 4.3: Overview of the key elements in Options 2A-2D

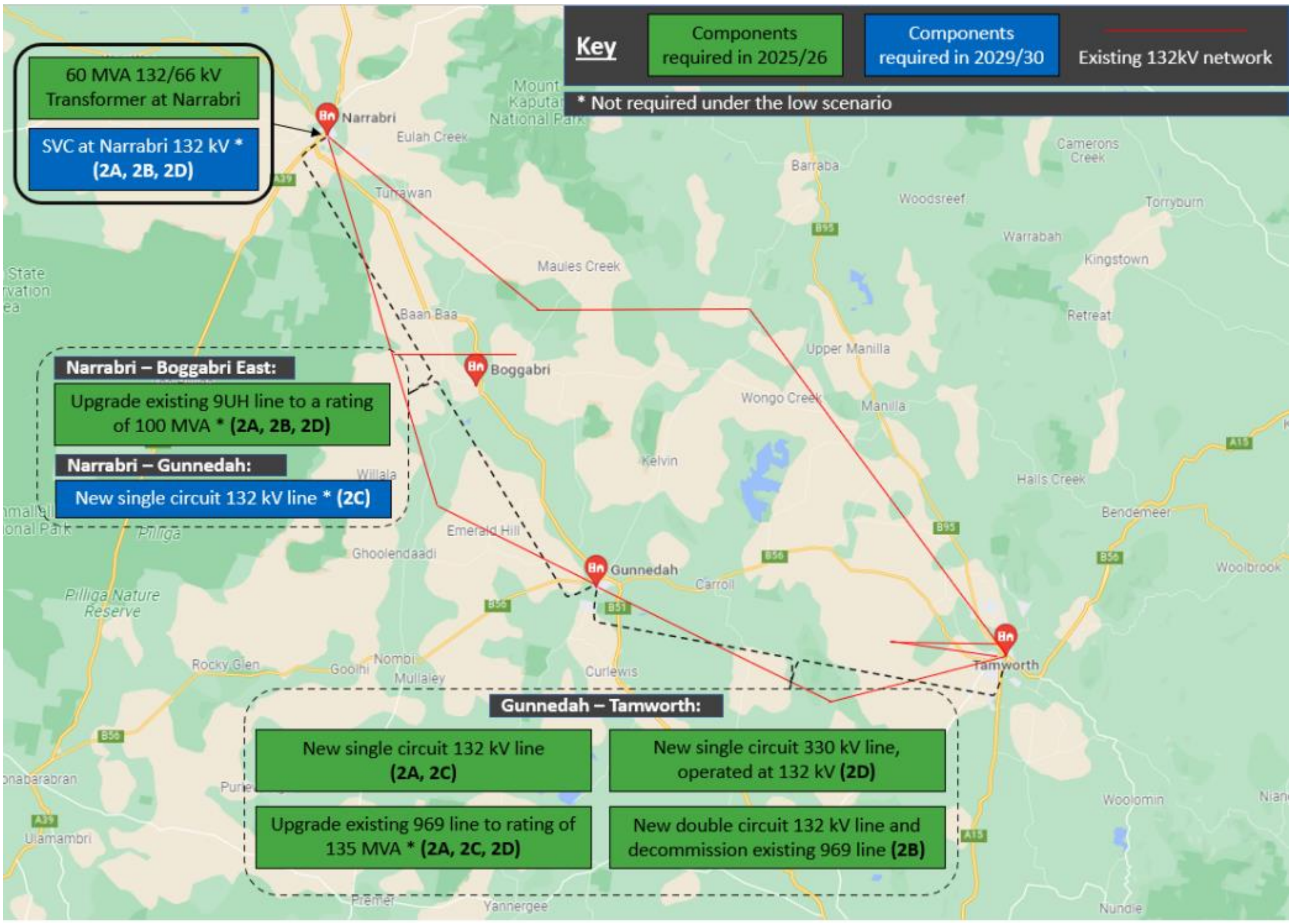


Table 4.5 summarises the expected construction time for each component.

Table 4.5: Summary of the expected construction time for each component of Options 2A-2D

Component	Expected construction time
Option 2A	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah.	62 months
• Upgrade the existing 969 line to a rating of 135 MVA • Upgrade the 9UH line to a rating of 100 MVA	70 months
• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	37 months
Option 2B	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new double circuit 132 kV line between Tamworth 330 kV and Gunnedah, each circuit rated at 160 MVA • Decommission the existing 969 transmission line	64 months
• Upgrade the 9UH line to a rating of 100 MVA	57 months
• Installation of a 132 kV +50 MVAr -20 MVAr SVC at Narrabri.	37 months
Option 2C	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new single circuit 160 MVA 132 kV line between Tamworth 330 kV and Gunnedah	62 months
• Upgrade the existing 969 line to a rating of 135 MVA	57 months
• Build a new single circuit 132 kV line between Narrabri and Gunnedah	61 months
Option 2D	
• Install a third 60 MVA 132/66 kV transformer at Narrabri • Build a new single circuit 330 kV line between Tamworth 330 kV and Gunnedah operated at 132 kV, rated at least 160 MVA	61 months
• Upgrade the existing 969 line to a rating of 135 MVA • Upgrade the 9UH line to a rating of 100 MVA	70 months
• Install a 132 kV +50 MVAr -20 MVAr SVC at Narrabri	37 months

4.3. Option 3 – Rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line

This option involves rebuilding line 969 to be a double circuit line with the three variants testing different line augmentations and dynamic reactive support levels. It represents a brownfield development and so is in line with Transgrid's preference to maintain social licence by utilising existing easements where possible.

The scope of the elements for Option 3A, Option 3B and Option 3C is shown in Table 4.1 above.

Table 4.6 summarises the optimal assumed timing for each component under the two different demand forecasts investigated.

Table 4.6: Summary of the assumed timing for each component of Options 3A-3C

Component	Expected timing (low)	Expected timing (central)
Option 3A		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah Substations as a double circuit	2025/26	2025/26
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2027/28
• Install a 132 kV +60 MVAr (capacitive) -20 MVAr (inductive) SVC at Narrabri Substation	N/A	2029/30
Option 3B		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah Substations as a double circuit	2025/26	2025/26
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2027/28
• Install a 50 MW (50 MWh) BESS at Narrabri 132 kV	N/A	2029/30
Option 3C		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah Substations as a double circuit	2025/26	2025/26
• Build a new single circuit 132 kV line between Narrabri and Gunnedah	N/A	2029/30

As outlined in section 2.3.6, following a more detailed review of the BESS components' ability to arbitrage outside of their network support commitments, the network owned BESS option (Option 3B) is now assumed to be able to arbitrage (to a small degree) and generate wider wholesale market benefits.

In addition, the cost of the BESS in Option 3B has been updated since the PADR to reflect a proposal from a proponent in response to the PADR.

Figure 4.4 below illustrates the type and location of the key elements for Options 3A-3C.

Figure 4.4: Overview of the key elements in Options 3A-3C

Table 4.7 summarises the expected construction time for each component.

Table 4.7: Summary of the expected construction time for each component of Options 3A-3C

Component	Expected construction time[39]
Option 3A	
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation • Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah Substations as a double circuit	44 months
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	56 months
• Install a 132 kV +60 MVAr (capacitive) -20 MVAr (inductive) SVC at Narrabri Substation	37 months
Option 3B	
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	44 months

[39] Please note that all expected construction times are presented as beginning from Design Gate 1 (DG1), which would commence approximately 1 month after the PACR.

• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah Substations as a double circuit	
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	56 months
• Install a 50 MW (50 MWh) BESS at Narrabri 132 kV	39 months
Option 3C	
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation • Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah Substations as a double circuit	44 months
• Build a new single circuit 132 kV line between Narrabri and Gunnedah	61 months

4.4. Option 5 – Non-network options

The three non-network options (Option 5A, Option 5B and Option 5C) use BESS to provide a network support service. These options vary by the size, number and location of the BESS. The details of these options have not been presented in this PACR to preserve the requested confidentiality by proponents.

We have assessed the technical feasibility of these options further since the PADR and consider, at this stage, that they are technically feasible and are able to address the identified need in a timely manner. We note that the connection process following the RIT-T will further assess and confirm the specific technical details of connection for the preferred option.

Table 4.8 specifies the minimum network support requirements for non-network options at Gunnedah (132 kV) that Transgrid will seek from proponents. Several parties have proposed larger solutions that provide other market services, in addition to providing this network support service.

Table 4.8: Minimum network support requirements for non-network options at Gunnedah

Year	MW – Thermal constraint	MVAr – Voltage constraint
2026	50 MW	20 MVAr
2029	55 MW	20 MVAr
2030	57 MW	20 MVAr

The non-network solutions are not considered to be long-term standalone solutions and, instead, defer or avoid the rebuilding of line 969 as a double-circuit line and upgrading the 9UH line between Narrabri and Boggabri North, as part of the preferred network option (Option 3A). Non-network options are not able to avoid or defer the need for the initial third transformer required at Narrabri under this option since capacity is required there immediately to address the IPART reliability standard for the Narrabri area.

Table 4.9 summarises the optimal assumed timing for each component under the two different demand forecasts investigated.

Table 4.9: Summary of the assumed timing for each component of Option 5A, Option 5B and Option 5C

Component	Expected timing (low)	Expected timing (central)
Option 5A		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Install a BESS at Gunnedah 132 kV as a network support service	Confidential	Confidential
• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	N/A	2029/30
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2029/30
Option 5B		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Install a BESS near Gunnedah 132 kV as a network support service	Confidential	Confidential
• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	N/A	2029/30
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2029/30
Option 5C		
• Install a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation	2025/26	2025/26
• Install a BESS at Gunnedah 132 kV as a network support service	Confidential	Confidential
• Rebuild the existing 969 line between Tamworth 330 kV and Gunnedah substations as a double circuit	N/A	2029/30
• Upgrade the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA	N/A	2029/30

4.5. Options considered but not progressed

We have also considered whether other options could meet the identified need. The reasons these options were not progressed are summarised in Table 4.10.

Table 4.10: Options considered but not progressed

Option	Reason(s) for not progressing
Capacitor banks/ switched capacitors	Not technically feasible. Our studies show that due to the expected extensive load growth in the Narrabri and Gunnedah areas, adding a number of additional capacitor banks or switched capacitors in the area is a non-credible solution since step changes in voltages caused by their switching would lead to voltage excursions outside NER requirements. This remains unchanged since the PSCR.

Option	Reason(s) for not progressing
Connection to the New England Transmission Infrastructure (NETI) project	This option was presented in the PSCR and involves connecting to a potential new non-prescribed project in the Gunnedah area called the NETI (a potential 330 kV transmission line between Tamworth 330/132 kV substation and a new 330 kV substation between Tamworth and Gunnedah with the aim of unlocking new renewable energy investment in the New England area of NSW). While ARENA has provided funding to Transgrid to assess the feasibility of an innovative commercial model to develop the NETI,[40] we removed the option of connecting to the potential NETI from the PADR assessment given the uncertainty involved (particularly around the timing). We considered this option not technically feasible at the PADR stage of the RIT-T and do not consider this to have changed since (e.g., no connection enquiry has been made).

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.

The construction of the scenarios and scope of the sensitivity testing has been a key amendment to the PACR following the AER dispute determination.

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.[41] It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options have been assessed under three scenarios as part of this PACR assessment, which differ in terms of the key drivers of the estimated net market benefits. The scenarios in this amended PACR have been updated in-line with the AER dispute determination and align with the 2021 IASR.

40 https://arena.gov.au/projects/transgrid-new-england-renewable-energy-zone/
41 The AER RIT-T Application Guidelines explicitly refer to the role of scenarios as the primary means of taking uncertainty into account. See: AER, *RIT-T Application Guidelines*, December 2018, p. 42.

Specifically, the three scenarios now reflect the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2021 IASR. They also vary by local spot load forecast and new local renewable generation assumptions, which are not parameters included in the ISP but which can be expected to have a material impact on the options considered in this RIT-T. We have aligned the higher local spot load forecast and higher new local generation assumptions with the ISP scenarios that reflect higher economic growth, so that the scenarios are internally consistent. The scenarios no longer vary the assumed network or non-network capital costs, the VCR or discount rate. This approach has been discussed and agreed with the AER following their dispute determination.

We have varied the local spot load forecasts across scenarios, although it is a departure from the scenarios included in the 2021 IASR, because:

- the identified need for this RIT-T is a localised issue; and
- local spot load forecasts are a key driver of the identified need, and are expected to have a material impact on the outcome of this RIT-T.

Table 5.1 summarises the specific key variables that influence the net benefits of the options under each of the scenarios considered. It also shows where there has been a change in an assumption from the initial PACR following the AER dispute determination (where the initial assumption is shown italicised in parentheses).

Table 5.1: Summary of scenarios (and changes since the initial PACR)

Variable	Step Change	Progressive Change	Hydrogen Superpower
Network capital costs	Base estimate	Base estimate *(Base estimate + 25%)*	Base estimate *(Base estimate – 25%)*
Non-network capital costs	Base estimate	Base estimate *(Base estimate + 25%)*	Base estimate *(Base estimate – 25%)*
Demand	Central demand forecast (as outlined in section 2.3.1)	Low demand forecast (as outlined in section 2.3.1)	Central demand forecast (as outlined in section 2.3.1)
New renewable generation in the area[42]	In-service generators from Appendix B.	In-service generators from Appendix B. *(All in-service and advanced generators)*	In-service and advanced generators from Appendix B. *(All in-service generators)*
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
VCR[43]	$46.88/kWh	$46.88/kWh *($32.82/kWh)*	$46.88/kWh *($60.95/kWh)*
Discount rate	5.50%	5.50% *(7.50%)*	5.50% *(1.96%)*

While there are changes to the assumed level of new renewable generation in two of the scenarios above (as a result of aligning these assumptions with the underlying economic growth assumptions for those IASR scenarios to ensure they are 'internally consistent'), we note that in practice this has had no effect on the analysis (and, in particular, the estimates of when the constraints may bind and the amount of unserved energy expected).[44]

While wholesale market benefits 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 and only affect the net benefits of four of the twelve options (i.e., those involving BESS, as outlined in section 2.2).

5.2. Weighting the reasonable scenarios

We have weighted each of the scenarios for this RIT-T based on the 2022 ISP weightings for the underlying wholesale market scenarios. 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.:[45]

- 52 per cent to the Step Change scenario;

[42] This table no longer refers to 'committed' generators as there are none for the NW Slopes area, as outlined in Appendix B.
[43] The VCRs used in this PACR have been updated since the PADR to reflect the updated underlying demand forecasts, i.e., the load that would be affected under the base case. However, we note that this update has had only a minor impact on the estimated VCRs.
[44] Specifically, the only difference between these two sets of assumptions is the treatment of 'advanced' generators, which for this RIT-T are all solar farms. Solar generation timing during a day does not align with the time of day when peak demand occurs and therefore the solar generation has an immaterial impact on unserved energy.
[45] 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 final 2022 ISP released in June 2022 – see: AEMO, *2022 Integrated System Plan*, December 2021, p. 75.

- 30 per cent to the Progressive Change scenario; and
- 18 per cent to the Hydrogen Superpower scenario.

These weights are the same as those used in the initial PACR, although we note that the underlying basis for the scenarios (and consequently the scenario parameters) have been updated in line with the AER dispute determination. The weights differ from those used in the PADR,[46] reflecting the fact that the wholesale market benefits have now been estimated across the three 2022 ISP scenarios, whereas the PADR only estimated wholesale market benefits for the Progressive Change scenario (as outlined in section 2.3.3).

While the above weights have been applied to weight the estimated market benefits and identify the preferred option across scenarios (illustrated in section 7), we have also carefully considered the results in each scenario in section 7. In addition, we have undertaken a sensitivity using alternative weightings (see section 7.5.5).

5.3. Sensitivity analysis

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing. The range of sensitivity tests has been expanded from the initial PACR in line with the AER dispute determination.

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

- the VCR;
- different commercial discount rates;
- capital costs for both network and non-network options;
- the impact of different spot load forecasts;
- scenario weightings; and
- the assumed timing of both the network and non-network components.

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

The above list of sensitivities focuses on the key variables that could impact the identified preferred option. The sensitivity testing also includes ‘boundary testing, where relevant, to investigate what key variables would need to change by in order to change the identified preferred option.

[46] The PADR weighted the central scenario at 50 per cent (given it is considered the most likely since it is based primarily on a set of expected assumptions), with the other two scenarios being weighted equally with 25 per cent each.

6. Estimating the market benefits

As outlined in section 2, the key benefit expected from the options is avoided involuntary load shedding in the North West Slopes area. In addition, for the two options that involve a non-network component, there are also expected to be benefits from anticipated changes in the wholesale market outcomes going forward.

The RIT-T requires categories of market benefits to be calculated by comparing the 'state of the world' in the base case where no action is undertaken, with the 'state of the world' with each of the credible options in place, separately. The 'state of the world' is essentially a description of the National Electricity Market (NEM) outcomes expected in each case, and includes the location and quantity of load in North West Slopes, as well as the type, quantity and timing of future generation investment.

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

EY has undertaken the wholesale market modelling component of the PACR assessment. Appendix F provides additional detail on the wholesale market modelling undertaken by EY. We also published a separate modelling report prepared by EY alongside the initial 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.

Under the base case, where the longer-term constraints associated with load growth in the North West Slopes area is unresolved, significant interruption of supply to loads in the area under normal and contingency conditions would be expected, due to voltage limitations and/or voltage collapse in the local supply network.

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

We have not quantified the avoided expected involuntary load shedding after 2028/29 as part of the PACR analysis since each option will address all constraints equally from then and avoid the same amount of unserved energy thereafter. Quantifying the full extent of avoided involuntary load shedding under each option after 2028/29 will therefore not assist in identifying the preferred option under the RIT-T. Moreover, the levels of unserved energy under the base case are expected to be extremely high and so will dwarf the other quantified costs and benefits if this approach is not applied (e.g., we estimate that these will exceed $550 million/year by 2029/30 under the central demand forecasts and increase thereafter).

Importantly, we have taken into account all avoided expected involuntary load shedding for the years in which the options differ in respect of how much involuntary load shedding will occur, ie, prior to 2028/29. This captures the *differences* in the expected avoided involuntary shedding *between* options as well providing an indication of the extent of these benefits overall.

We consider this is consistent with the approach adopted in other RITs, the Energy Networks Australia RIT-T Handbook[47] and advice provided to the AER.[48]

6.2. Avoided involuntary load shedding in the North West Slopes area

We have run system studies to estimate the Expected Unserved Energy (EUE) in the North West Slopes area under each of the base cases and each of the credible options.

The avoided EUE for each option has been valued using the estimated VCRs published by the AER.[49] Specifically, we have developed a load-weighted VCR estimate of $46.88/kWh using the AER VCR values for the customer groups relevant to the region as shown in Table 6.1.

Table 6.1: Load weighted VCR breakdown ($2021)

	Residential	Commercial	Industrial	VCR estimate
AER VCR estimate[50]	$26.8/kWh	$46.2/kWh	$66.2/kWh	$46.88
North West Slopes load breakdown	34%	29%	37%	

We have also applied VCR estimates that are 30 per cent lower and 30 per cent higher as part of our sensitivity testing, consistent with the AER's specified +/- 30 per cent confidence interval.[51]

The EY market modelling has also quantified the impact of changes in involuntary load shedding *outside* of the North West Slopes area associated with the implementation of each credible option via the time sequential modelling component of the market modelling. Specifically, the modelling estimates the MWh of EUE in each hourly trading interval over the modelling period, and then applies the AER VCRs to quantify the estimated value of avoided EUE outside of the North West Slopes area for each option. However, these estimated changes in EUE are not expected to be material for any of the credible options.

6.3. Options replacing line 969 would avoid future wood pole replacement costs

Under the base case, we expect to replace aged wood pole structures on line 969 within the next twenty years. The expected timing of this work is between 2026/27 and 2044/45 and is the same as assumed in the PADR.

For all options that replace line 969 with a new line (i.e., Option 2B, Option 3A, Option 3B, Option 3C, Option 5A, Option 5B and Option 5C), this expenditure is able to be avoided and so provides an economic benefit in the analysis. However, given the majority of the expenditure is expected in the last few years of the assessment period, it is found to be a minor source of benefit for these options.

6.4. Wholesale market benefits

As outlined in section 2.2, four of the credible options assessed in this PACR involve the use of BESS and are able to use a portion of their capacity to dispatch to the wholesale market. Dispatching to the wider market

47 ENA, *RIT-T Economic Assessment Handbook for non-ISP RIT-Ts*, Version 2.0, 26 October 2020, p. 51.
48 Biggar, D., *An Assessment of the Modelling Conducted by TransGrid and Ausgrid for the 'Powering Sydney's Future' Program*, May 2017, pp. 12-16.
49 The VCR values have been taken from the most recent VCR update from the AER at the time of preparing the initial PACR, i.e.: AER, *Annual update – VCR review final decision – Appendices A – E*, December 2021.
50 See AER, *Annual update – VCR review final decision – Appendices A to E – December 2021*.
51 AER, *Values of Customer Reliability – Final Report on VCR values*, December 2019, p. 84.

can offset more costly generation that would otherwise operate in the NEM and thus provide wider wholesale market benefits on top of the avoided unserved energy that all options provide.[52]

These wider benefits have been estimated by way of wholesale market modelling conducted by EY. Appendix F summarises the key variables under the three scenarios modelled that influence the wholesale market benefits of the options. Additional detail on the wholesale market modelling undertaken, including the assumptions and methodologies, can be found in the accompanying EY market modelling report.

Table 6.2 below summarises the specific categories of wholesale market benefit under the RIT-T that have been modelled as part of this PACR.

Table 6.2: Categories of wholesale market benefit under the RIT-T that have been modelled as part of this PACR

Market benefit	Overview
Changes in costs for other parties in the NEM	This category of market benefit is expected where credible options result in different investment patterns of generators and large-scale storage across the NEM, compared to the base case. The capital and operating costs associated with the BESS components have been captured in the PACR assessment as a cost to other parties, reflecting that this is an additional resource cost to the NEM that would not be incurred if we did not sign a network support agreement with the proponents for these options (as these projects are not already committed or anticipated). This is consistent with the AER's revised guidance on the treatment of non-network options.[53] However, the market benefits associated with these options operating outside of times needed for network support (in particular their impact on dispatch costs and generation investment), compared with the base case in which those batteries are not in place, has also been captured as part of the modelling for each of these options.
Changes in fuel consumption in the NEM	This category of market benefit is expected where credible options result in different patterns of generation and storage dispatch across the NEM, compared to the base case. Where non-network options are able to trade in the wholesale market outside of their network support commitments, this may result in a different pattern of generation dispatch.
Changes in network losses	The time sequential market modelling has taken into account the change in network losses that may be expected to occur as a result of the implementation of each of the credible options, compared with the level of network losses which would occur in the base case, for each scenario. The benefit of changes to network losses is captured within the wholesale market modelling of dispatch cost benefits of avoided fuel costs and changes to voluntary and involuntary load shedding. The reduction in network losses between the base case and the options is considered immaterial for the options considered in this PACR but reduces both the energy to be produced by fossil fuel generators to account for the losses, and a reduction in new capacity that has to be built to supply demand, particularly during peak periods.
Differences in unrelated	This benefit category relates to the costs of intra-regional transmission investment associated with the development of REZ that could be avoided if a credible option is pursued.

52 While the other credible network options (i.e., the solely network options) will provide additional system strength to the North West Slopes region, we do not consider there to be material wholesale market benefits associated with these options, as outlined in section 2.3.

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

Market benefit	Overview
transmission costs	AEMO has identified a number of REZ in various NEM jurisdictions as part of the ISP and has included allowances for transmission augmentations that it considers would be required to develop those REZ. While the credible options being considered in this RIT-T can in theory assist with allowing the development of some of these REZ without the need for additional intra-regional transmission investment (or with less of it), it is in a very minor way and this category of market benefit is not considered significant for this RIT-T.
Changes in involuntary load curtailment (outside of the North West Slopes area)	This market benefit involves quantifying the impact of changes in involuntary load shedding associated with the implementation of each relevant credible option via the time sequential modelling component of the market modelling. Specifically, the modelling estimates the MWh of unserved energy (USE) in each trading interval over the modelling period, and then applies a Value of Customer Reliability (VCR, expressed in $/MWh) to quantify the estimated value of avoided USE for each option. We have adopted the AER VCRs to quantify the estimated value of avoided EUE for the purposes of this assessment. This category of market benefit has been found to be relatively small within the market modelling. This is due to there not being a material difference in the quantity of involuntary load shedding outside of the North West Slopes area between each option and the base case.
Changes in voluntary load curtailment	Voluntary load curtailment is when customers agree to reduce their load once wholesale prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances. Where the implementation of a credible option affects wholesale price outcomes, and in particular results in wholesale prices reaching higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment. This class of market benefit has been found to be relatively low within the market modelling, reflecting that the level of voluntary load curtailment is not significantly different between the option cases and the base case.

6.5. General modelling parameters adopted

The RIT-T analysis spans a 20-year assessment period from 2022/23 to 2041/42. This period is the same as the initial PACR and begins and ends a year later than the PADR and reflects the passage of time since that document was released.

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

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 amended PACR, consistent with the assumptions adopted in the 2021 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,[54] and an upper bound discount rate of 7.50 per cent (i.e., the upper bound proposed for the 2022 ISP[55]).

6.6. Classes of market benefit not considered material

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

Competition benefits have not been estimated for any of the options since they are not considered material in the context of this RIT-T. This RIT-T is focussed on efficiently meeting the required reliability standards in the North West Slopes area and, while some options are expected to generate a level of wholesale market benefits, it is not considered sufficient to affect the competitiveness of generator bidding behaviour in any region of the NEM.

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 are sufficiently flexible to respond to that change. The credible options outlined in this PACR exhibit flexibility in terms of how they can be developed and we have captured the option value of this flexibility implicitly through their components having different assumed timings across the scenarios. We consider this consistent with the AER guidance on the treatment of option value and consider that a wider option value modelling exercise would be disproportionate to any option value that may be identified for this specific RIT-T assessment.

The options are also not expected to have a material impact on ancillary services costs in the NEM. Specifically, each of the options have been designed to resolve the voltage issues on the network and so solve the expected FCAS issues in an identical manner. The options that involve BESS components are not expected to be able to sell services into the FCAS market (given they will be resolving the voltage issues).

54 This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: AER, *Final decision – Powerlink transmission determination 2022-27 post-tax revenue model – April 2022.xlsx*, 'WACC' sheet, cell R23..
55 AEMO, *2021 Inputs, Assumptions and Scenarios Report*, July 2021, p. 105.
56 NER clause 5.16.1(c)(6).

7. Net present value results

This section outlines the results of the economic assessment we have undertaken of the credible options. Specifically, it applies the amended scenario assumptions (summarised in section 5.1) and presents an expanded set of sensitivities (as summarised in section 5.3).

Due to the confidentiality requested by the proponents of the non-network solutions, we are only able to present the overall *net* market benefits of Option 5A, Option 5B and Option 5C (i.e., the present value of the aggregate market benefits estimated less the present value of the aggregate costs).

The market modelling report accompanying the initial PACR prepared by EY provides additional detail in terms of the modelled wholesale market impacts for each option, which remains relevant for this amended PACR. Neither this PACR nor the EY market modelling report provide the estimated wholesale market benefits of the non-network options in dollar terms, in order to preserve the confidentiality of the options assessed. The full analysis has been provided in-confidence to the AER as part of their role in overseeing the RIT-T.

All figures of the same type in this section have been presented on the same scale (unless otherwise stated) in order to highlight the differences across scenarios.

7.1. Step Change scenario

This scenario includes EY's market modelling of the wholesale market benefits for the BESS options based on the 'Step Change' scenario from the 2021 IASR. It also assumes the central demand forecasts (outlined in section 2.3.1) and the in-service renewable generators from Appendix B.

Under these assumptions, two of the options involving non-network solutions in the short-term (i.e., Option 5B and Option 5C) are preferred over the solely network options. This is primarily due to these options being able to be commissioned approximately one to two years before the network options, which allows them to avoid substantial additional unserved energy.

Option 5B is the top-ranked option overall, with estimated net benefits that are approximately $16 million (3 per cent) greater than Option 5C and $45 million (8 per cent) greater than Option 3A.[57] The third non-network option, Option 5A, is found to have net market benefits that are $20 million (3 per cent) below Option 3A.

Option 3A is the top-ranked purely network option. While it has the second lowest expected total cost of the network options, in present value terms, it can avoid a substantial amount of unserved energy one to two years earlier than the lowest cost network option (Option 2B) and so provides greater benefits.[58]

Figure 7.1 shows the overall estimated net benefit for each option under the Step Change scenario. All figures of this format in the PACR show the top-ranked options in green, and the other options in blue.

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[57] Please note that while this sentence, and all sentences of this type in the PACR, presents the percentage differences between options, these percentages are calculated excluding the avoided expected unserved energy after 2028/29 as it is common to all options (and so does not assist in identifying the preferred option), as outlined in section 6.1. These percentages should therefore be interpreted as being based on net benefit numbers that exclude the superfluous unserved energy, as opposed to being based on the *total* expected net benefit numbers.

[58] The present value of all capex and opex of Option 3A under this scenario is $101 million, which compares to $93 million for Option 2B.

Figure 7.1: Summary of the estimated net benefits under the Step Change scenario

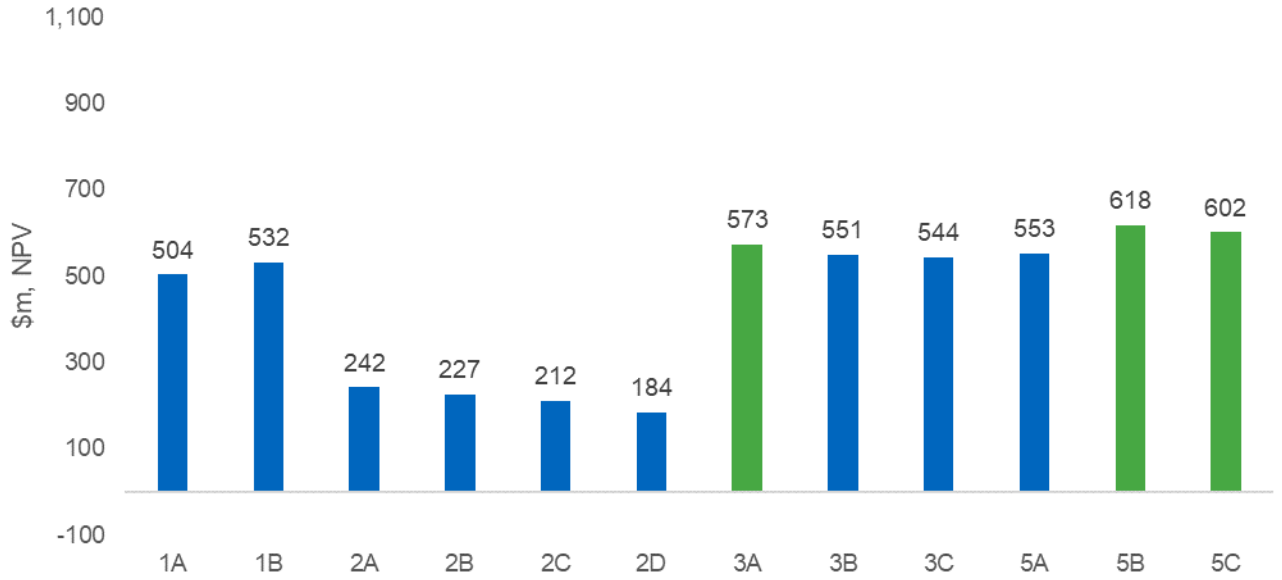
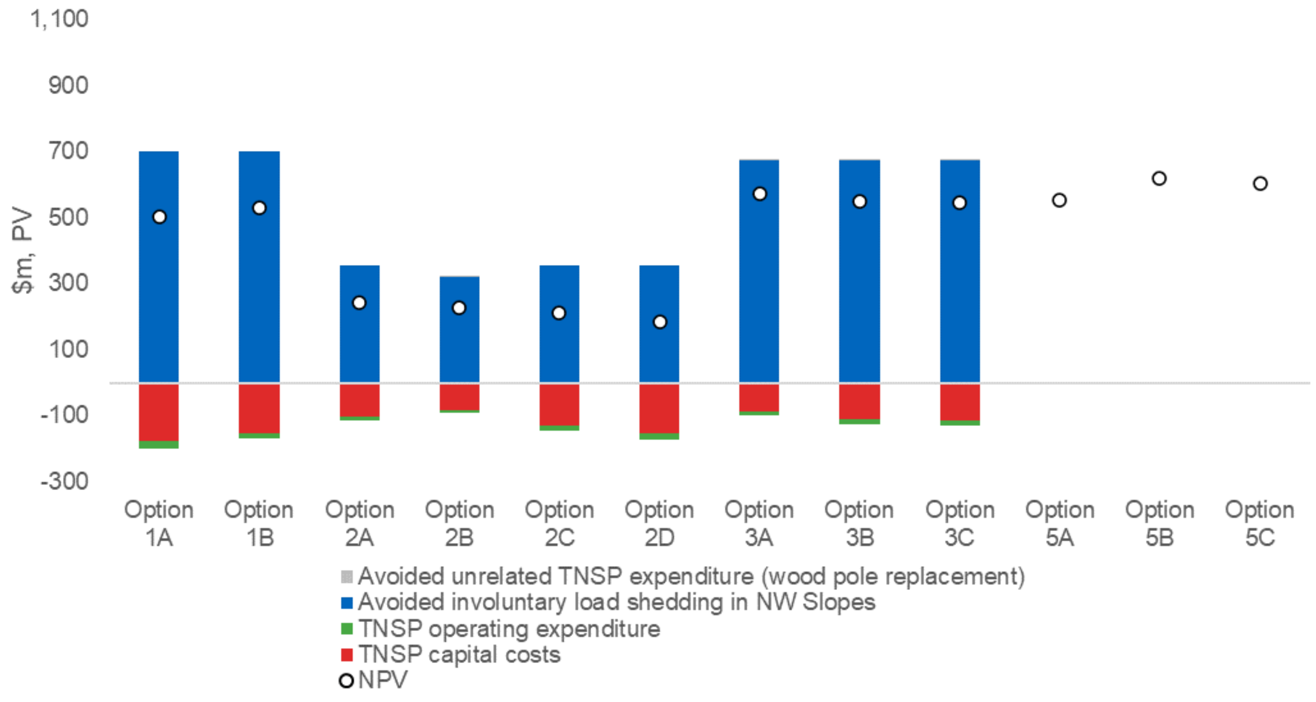


Figure 7.2 shows the composition of estimated net benefits for each option under the Step Change scenario. Only the net numbers are shown for Option 5A, Option 5B and Option 5C in order to protect the confidentiality of these options. The level of wholesale market benefits for Option 3B (the Transgrid-owned BESS option) has also been redacted from this figure (and all figures of this type in the PACR) to avoid any inferences being made regarding the costs (or benefits) of the non-network options.

Figure 7.2: Breakdown of estimated net benefits under the Step Change scenario



The wholesale market modelling for the options involving BESS finds that the primary source of benefit is from avoided and deferred capex for new generation/storage (making up approximately 80 per cent of the wholesale market benefits for the non-network BESS options under this scenario). However, the wholesale market benefits are relatively minor in the overall assessment for this scenario and only contribute between 6 and 8 per cent of the total estimated gross market benefits for the three non-network BESS options (and less than 1 per cent for Option 3B, which has a grid-owned BESS).

7.2. Progressive Change scenario

This scenario includes EY's market modelling of the wholesale market benefits for the BESS options based on the 'Progressive Change' scenario from the 2021 IASR. It also assumes the low demand forecasts (outlined in section 2.3.1) and the in-service renewable generators from Appendix B.

Under these assumptions, Option 5B is the top ranked option with estimated net benefits that are $9.3 million (12.5 per cent) greater than the next highest ranked option. Option 1A and Option 1B are the top-ranked purely network options, marginally ahead of Option 3B (by $4.3 million). Option 5C and Option 5A are $18.5 million (22 per cent) and $49.7 million (60 per cent) behind Option 5B, respectively.

This represents a change from the initial PACR where Option 1A and Option 1B were the highest ranked options under the 'low economic benefits' scenario assessed at the time. However, it remains the case that, in absolute terms, the expected net benefits of the Option 1, Option 3, and Option 5 variants are relatively close under this scenario.

All options are found to have much lower net benefits under this scenario compared to the Step Change scenario, which is driven by the significantly lower avoided unserved energy benefits. We note that if we did not apply the approach to removing unserved energy, that has no bearing on the ranking of the options (outlined in section 6.1), all options would be found to have significantly positive net benefits.

Figure 7.3 shows the overall estimated net benefit for each option under the Progressive Change scenario.

Figure 7.3: Summary of the estimated net benefits under the Progressive Change scenario

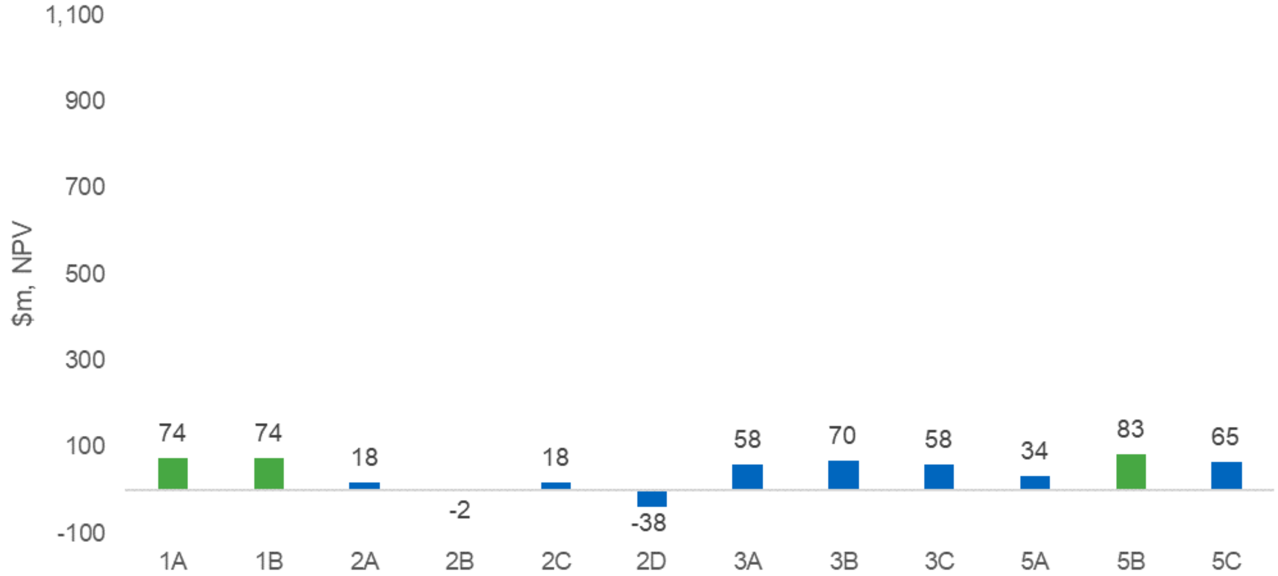
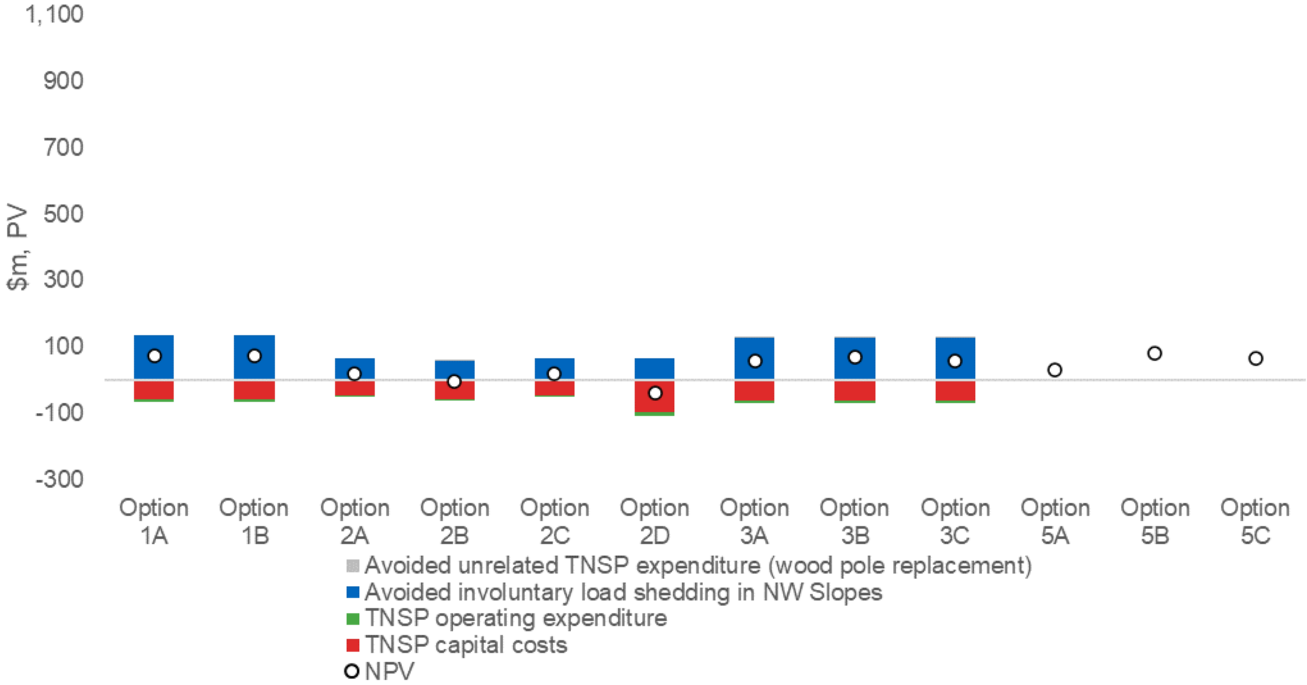


Figure 7.4 shows the composition of estimated net benefits for each option under this scenario. Only the net numbers are shown for Option 5A, Option 5B and Option 5C to protect the confidentiality of these options.

Figure 7.4: Breakdown of estimated net benefits under the Progressive Change scenario



As under the Step Change scenario, the wholesale market benefits are comprised almost exclusively of avoided and deferred capex for new generation/storage (making up approximately 100 per cent of the wholesale market benefits for the non-network BESS options under this scenario). However, in contrast to the Step Change scenario, the wholesale market benefits make up between 33 and 38 per cent of the total estimated gross benefit for the three non-network BESS options under the Progressive Change scenario (and 8 per cent for Option 3B, which has a grid-owned BESS). We note however that if the full amount of expected unserved energy was included in this scenario (i.e., not the approach outlined in section 6.1), these percentages would fall substantially.

While this scenario includes EY's market modelling of the wholesale market benefits for the BESS options based on the 'Progressive Change' scenario used in the 2022 ISP, the wholesale market modelling finds that the Progressive Change scenario has marginally greater expected wholesale market benefits from the BESS options compared to the other two scenarios. This is due to the wholesale market modelling finding that significant new open cycle gas turbine (OCGT) capacity can be avoided with the BESS options for the Progressive Change scenario, compared to the other two scenarios.[59] However, we note that the variation in the level of wholesale market benefits estimated across the three scenarios is minor and considered immaterial to the overall PACR conclusion.

7.3. Hydrogen Superpower scenario

This scenario includes EY's market modelling of the wholesale market benefits for the BESS options based on the 'Hydrogen Superpower' scenario from the 2021 IASR. It also assumes the central demand forecasts (outlined in section 2.3.1) and the in-service and 'advanced' renewable generators from Appendix B.

[59] The relatively high level of new OCGT investment expected under the base case for the Progressive Change scenario, which is able to be avoided by the BESS options, is due to the interaction between the retirement of Eraring in 2025-26, the timing of Humelink in 2035-36 (compared to 2027-28 and 2028-29 for the other two scenarios) as well as the relatively relaxed carbon constraint.

Under these assumptions, as with the Step Change scenario, two of the options involving non-network solutions in the short-term (i.e., Option 5B and Option 5C) are preferred over the solely network options. This is again due to these options being able to be commissioned approximately one to two years before the network options, which allows them to avoid substantial additional unserved energy.

Option 5B is the top-ranked option overall, with estimated net benefits that are approximately $19 million (3 per cent) greater than Option 5C and $51 million (9 per cent) greater than Option 3A. The third non-network option, Option 5A, is found to have net market benefits that are within 5 per cent of Option 3A under this scenario.

As with the Step Change scenario, Option 3A is the top-ranked purely network option. While it has the second lowest expected total cost of the network options, in present value terms, under this scenario, it can avoid a substantial amount of unserved energy one to two years earlier than the lowest cost network option (Option 2B), and so has greater net benefits.[60]

Figure 7.5 shows the overall estimated net benefit for each option under the Hydrogen Superpower scenario.

Figure 7.5: Summary of the estimated net benefits under the Hydrogen Superpower scenario

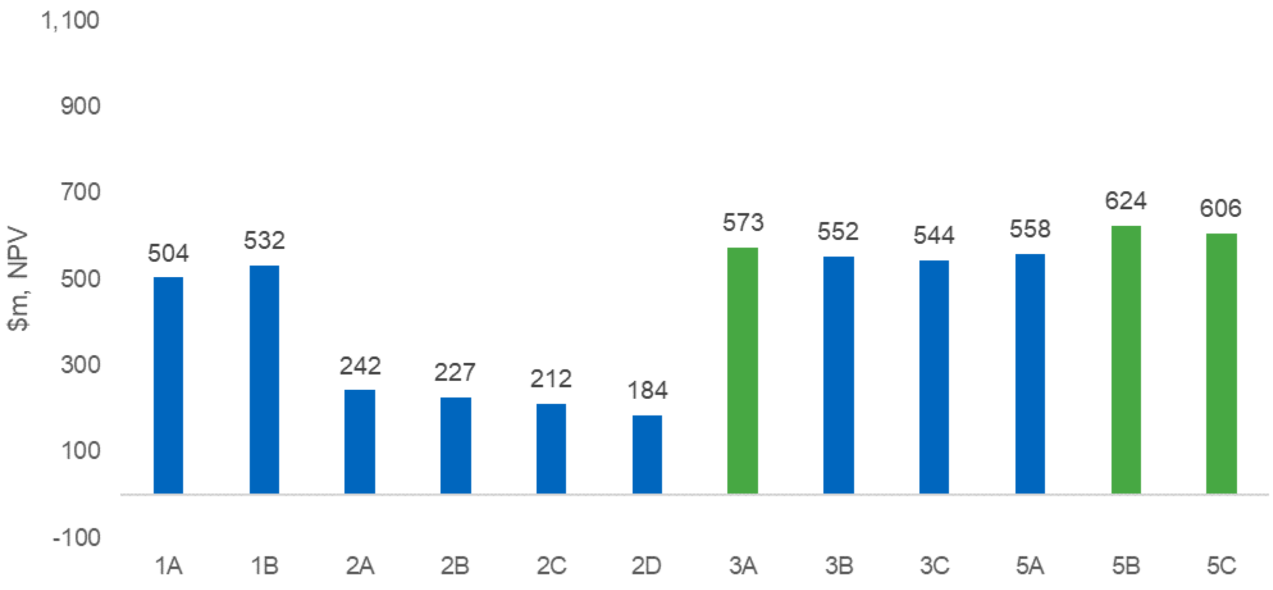
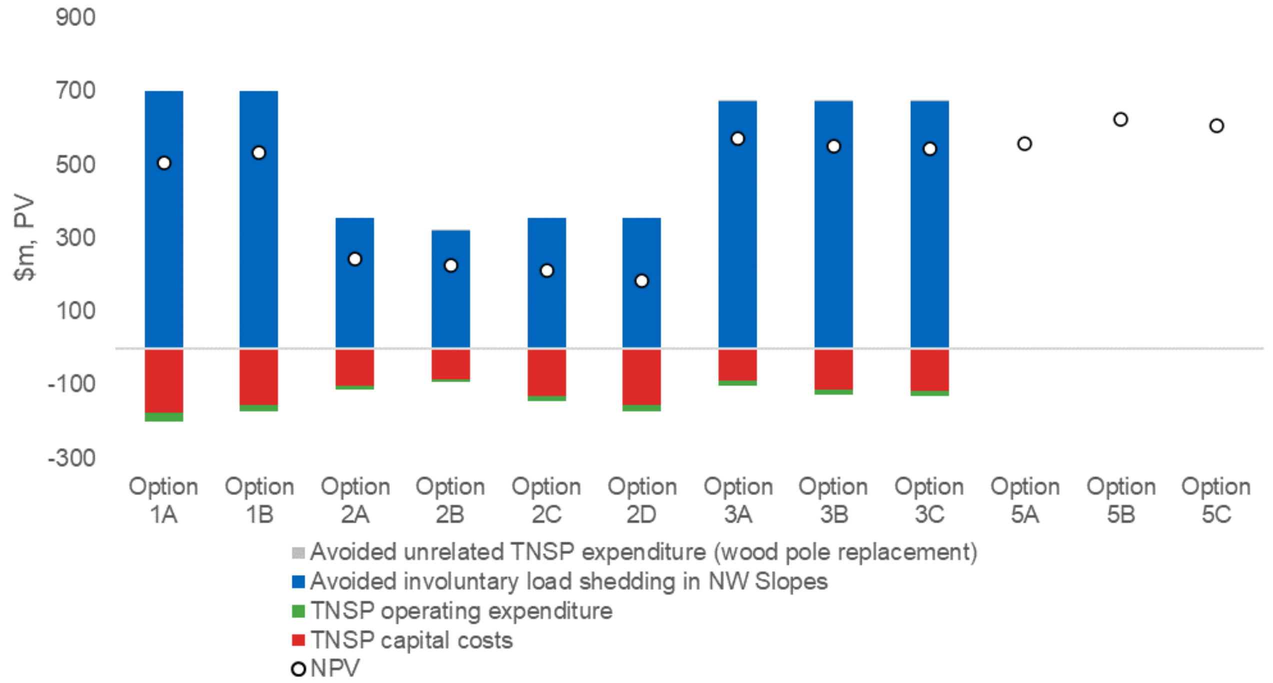


Figure 7.6 shows the composition of estimated net benefits for each option under this scenario. Only the net numbers are shown for Option 5A, Option 5B and Option 5C in order to protect the confidentiality of these options.

60 The present value of all capex and opex of Option 3A under this scenario is $101 million, which compares to $93 million for Option 2B.

Figure 7.6: Breakdown of estimated net benefits under the Hydrogen Superpower scenario



As under the Step Change scenario, the wholesale market benefits are comprised almost exclusively of avoided and deferred capex for new generation/storage (making up between 88 and 97 per cent of the wholesale market benefits for the non-network BESS options under this scenario). The wholesale market benefits are also minor in the overall assessment for this scenario and only contribute between 7 and 9 per cent of the total estimated gross market benefits for the three non-network BESS options (and 0.8 per cent for Option 3B, which has a grid-owned BESS).

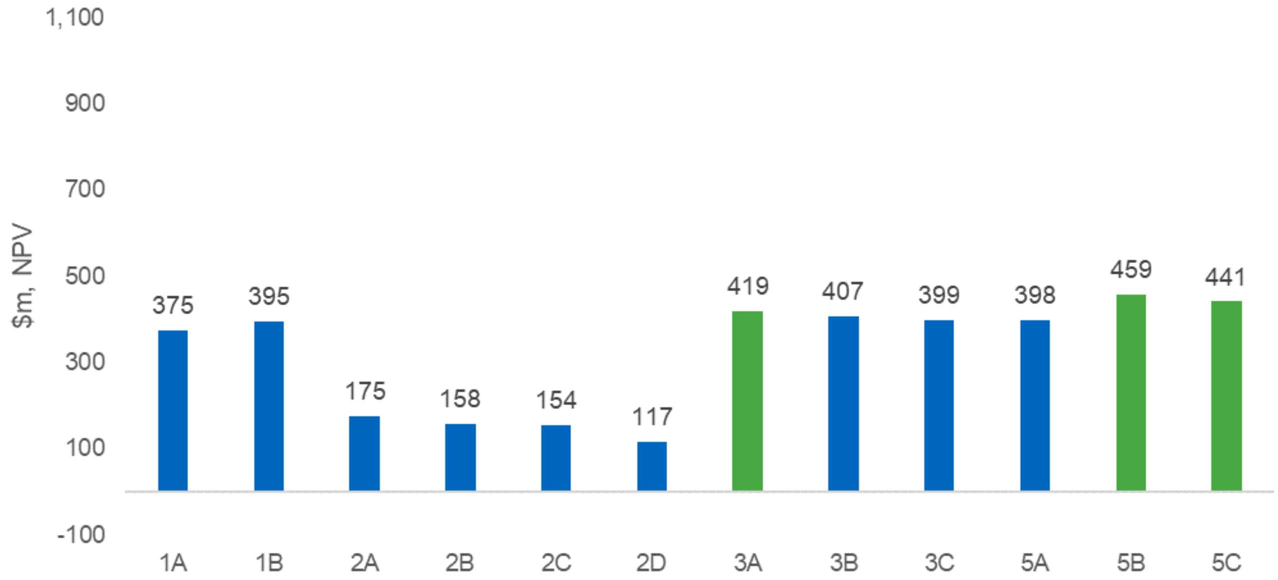
7.4. Weighted net benefits

Figure 7.7 shows the estimated net benefits for each of the credible options weighted across the three scenarios investigated (and discussed above).

Under the weighted outcome, two of the options involving non-network solutions in the short-term (i.e., Option 5B and Option 5C) are found to be ranked effectively equally and be preferred over the solely network options.

Option 5B has the greatest estimated net market benefits, with net benefits that are approximately $17 million (4 per cent) greater than the second ranked option (Option 5C) and $40 million (10 per cent) greater than the top-ranked solely network option (Option 3A). The third non-network option, Option 5A, is found to have net market benefits that are $20 million (5 per cent) below Option 3A.

Figure 7.7: Summary of the estimated net benefits, weighted across the three scenarios



Option 5B has the greatest estimated net benefits on a weighted basis and in each scenario. This is a minor change from the initial PACR, where Option 5B was the top option on a weighted basis and in the central and high economic benefits scenarios assessed at the time, but not in the low economic benefits scenario.

Option 5C is ranked above Option 3A in all scenarios but is ranked below Options 1A, 1B and 3B in the Progressive Change scenario. The Progressive Change scenario would need to be weighted at least 88 per cent, with the other two scenarios weighted relative to their ISP weights, for Option 5C to be ranked below a purely network option on a weighted basis.

Overall, a key determinant of the overall preferred option is the assumed build times, and ultimate commissioning dates, of each of the credible options since options that can be commissioned sooner allow for substantial amount of unserved energy to be avoided. This is investigated further in section 7.5.1 below.

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. The range of sensitivity tests has been expanded from the initial PACR in-line with the AER dispute determination.

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

- the VCR;
- different commercial discount rates;
- capital costs for both network and non-network options;
- the impact of different spot load forecasts;
- scenario weightings; and
- the assumed timing of both the network and non-network components.

Each of the sensitivity tests undertaken in this PACR are discussed in the sections below. Each sensitivity test has been undertaken for all scenarios, consistent with the AER dispute determination,[61] but the discussion of each focuses on the weighted outcome since it is what is relevant for the RIT-T.

We note that the scale in some of the figures in this section is smaller than their counterparts in earlier sections in order to show the impact of these sensitivities more clearly.

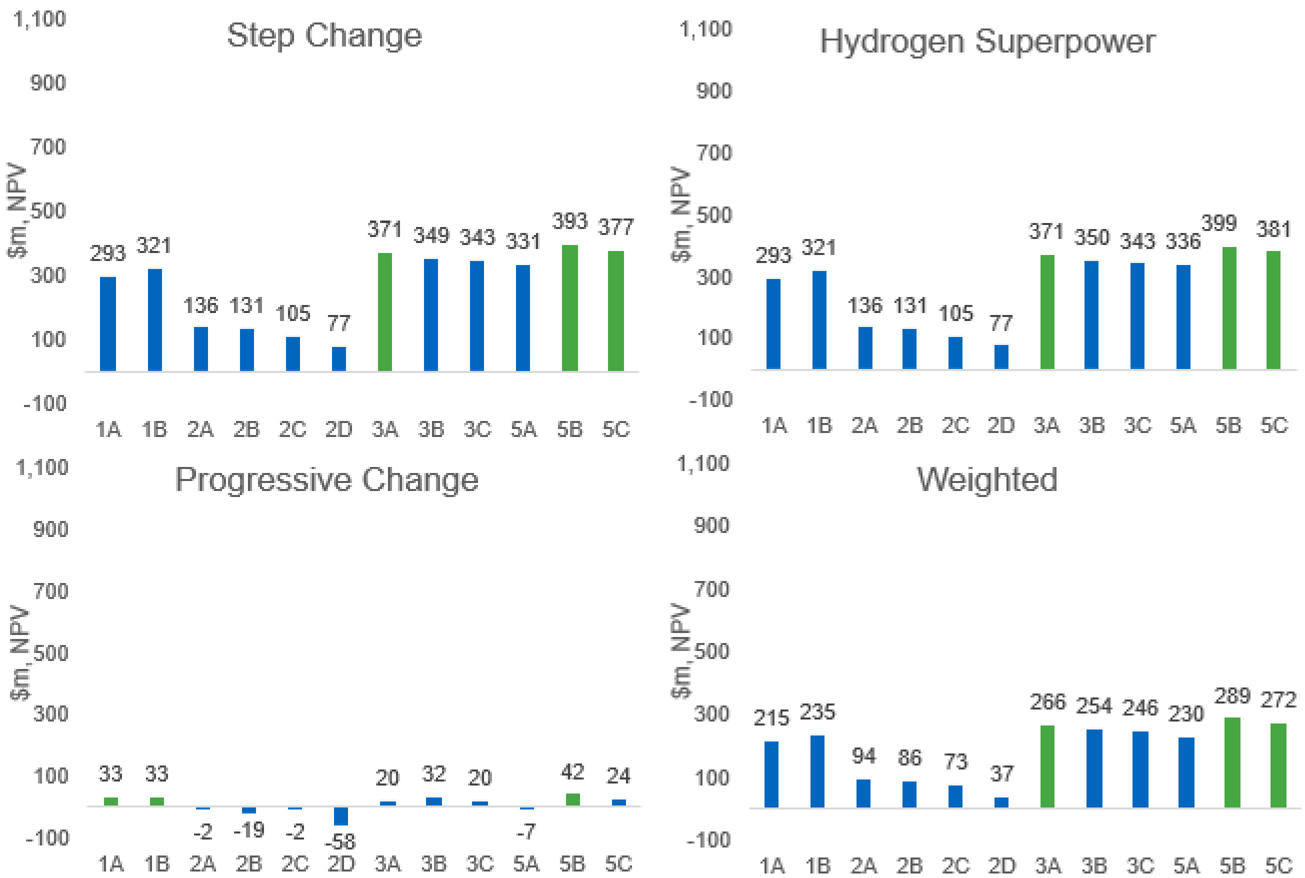
7.5.1. VCR

Estimates of the VCR are crucial to determining the value of avoided unserved energy but are subject to uncertainty and so, in addition to using the central VCR estimates, we have also assumed VCR estimates that are 30 per cent lower and 30 per cent higher, consistent with the AER's specified +/- 30 per cent confidence interval.[62]

The ranking of the options on a weighted basis does not change under either sensitivity.

Figure 7.8 presents the results under the 30 per cent lower VCR of $32.82/kWh.

Figure 7.8: Weighted net benefits under a 30 per cent lower VCR

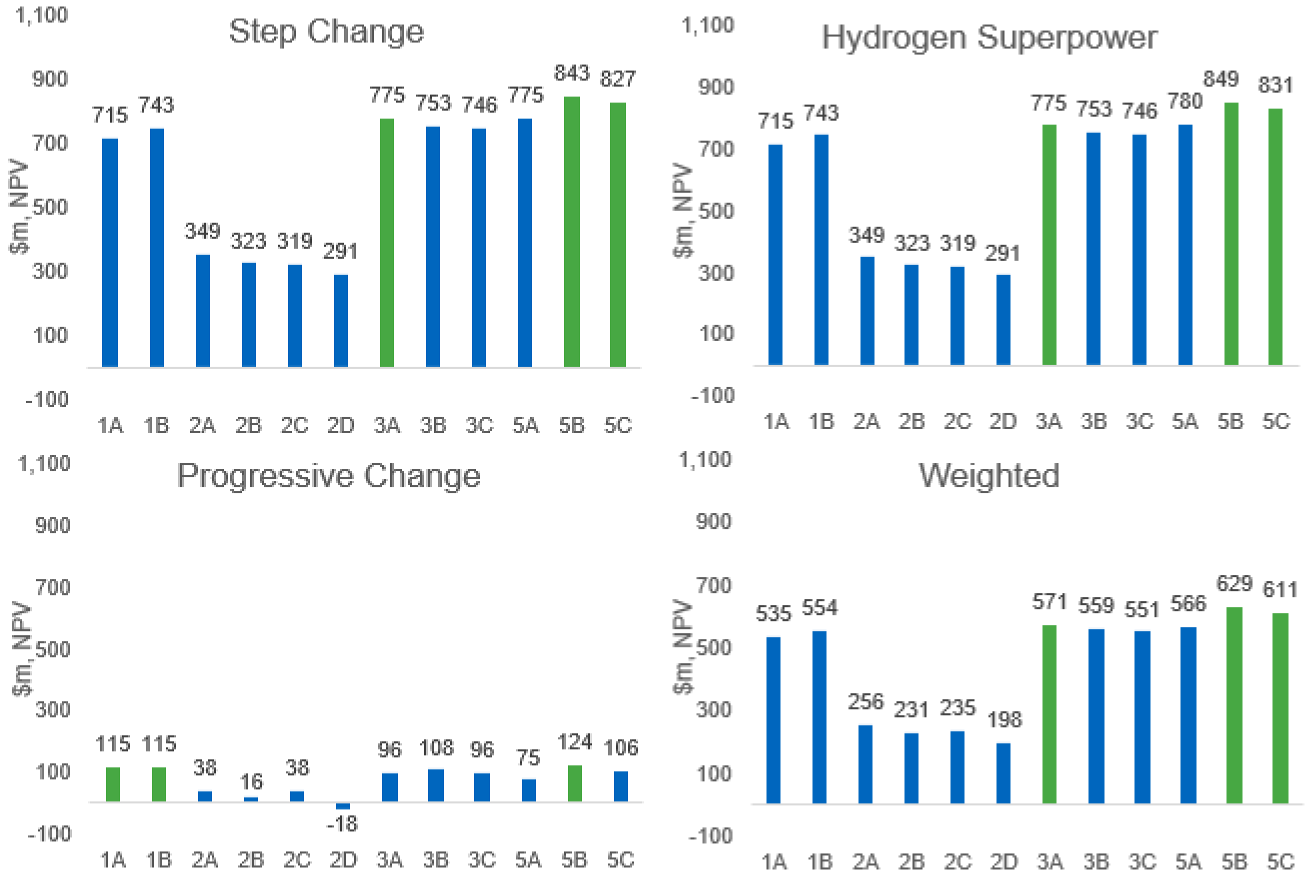


61 AER, *Decision: North West Slopes and Bathurst, Orange and Parkes Determination on dispute - Application of the regulatory investment test for transmission*, November 2022, p. 6.

62 AER, *Values of Customer Reliability – Final Report on VCR values*, December 2019, p. 84.

Figure 7.9 presents the results under the 30 per cent higher VCR of $60.95/kWh.

Figure 7.9: Weighted net benefits under a 30 per cent higher VCR



7.5.2. Commercial discount rate

The discount rate directly affects the trade-off between costs now and benefits in the future.

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 amended PACR, consistent with the assumptions adopted in the 2021 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,[63] and an upper bound discount rate of 7.50 per cent (i.e., the upper bound proposed for the 2022 ISP[64]).

Neither sensitivity changes the ranking of the options on a weighted basis.

[63] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: AER, *Final decision – Powerlink transmission determination 2022-27 post-tax revenue model – April 2022.xlsx*, 'WACC' sheet, cell R23..

[64] AEMO, *2021 Inputs, Assumptions and Scenarios Report*, July 2021, p. 105.

Figure 7.10 presents the results under an upper bound discount rate of 7.50 per cent.

Figure 7.10: Weighted net benefits under a 7.5 per cent discount rate

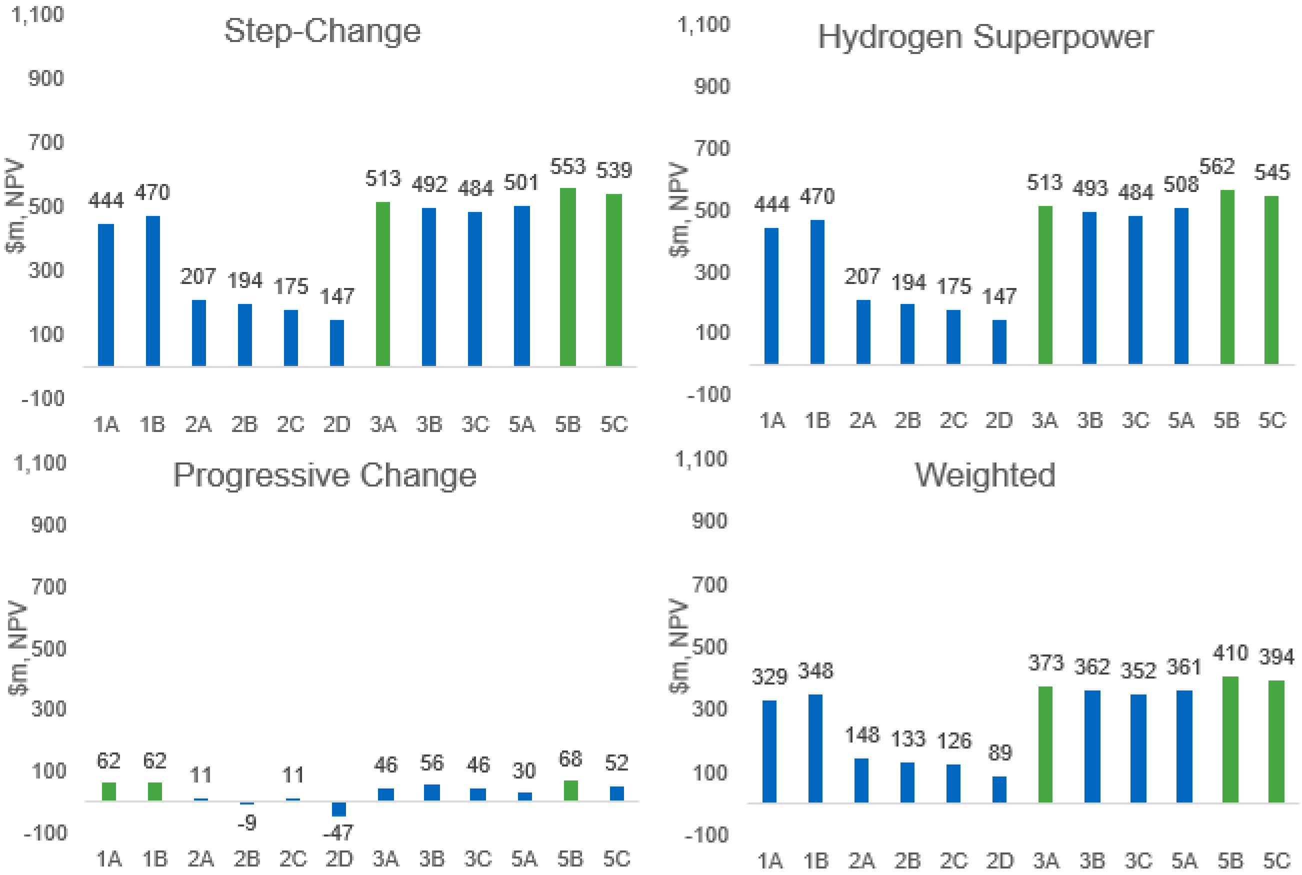
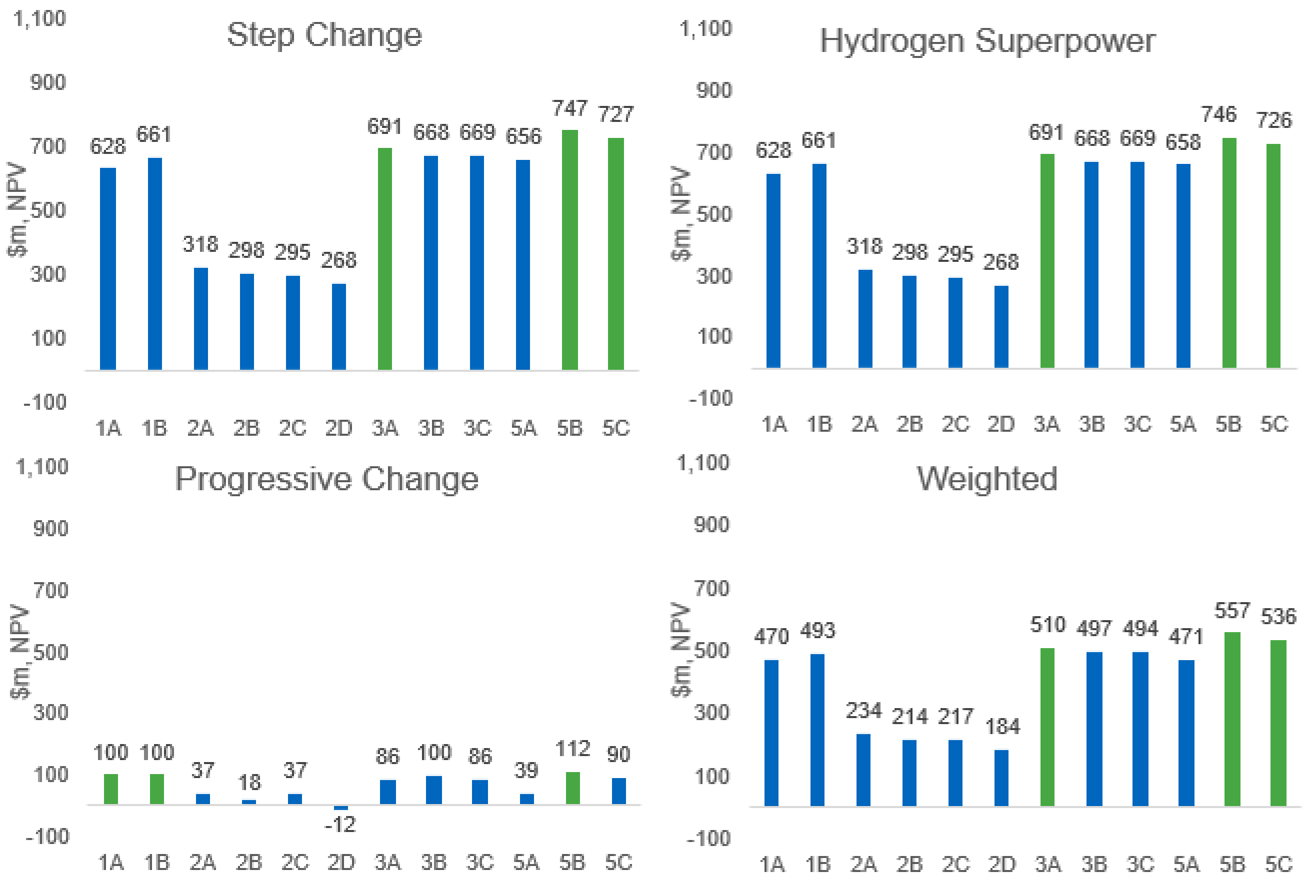


Figure 7.11 presents the results under a lower bound discount rate of 2.3 per cent, based on the latest regulated pre-tax WACC for an electricity transmission business in the NEM.[65]

Figure 7.11: Weighted net benefits under a 2.3 per cent discount rate



We further find that there is no realistic discount rate that would result in Option 3A being preferred over Option 5B (the discount rate would need to exceed 31 per cent).

7.5.3. Capital costs for both network and non-network options

We have investigated the sensitivity of the option rankings to differences in the capital cost forecasts.

Changing the capital costs for both network and non-network options (25 per cent lower and higher) does not change the top ranked option on a weighted basis. This is because the primary driver of differences between the options is the difference in avoided unserved energy benefits.

[65] AER, *Final decision – Powerlink transmission determination 2022-27 post-tax revenue model – April 2022.xlsx*, 'WACC' sheet, cell R23. We note that applying a discount rate of 1.96 per cent, as per the AER's previous final decision for AusNet Services (which was the latest final decision at the time of the initial PACR), also would not change the rankings of the options.

Figure 7.12 shows the results with 25 per cent higher network capital costs. Under this sensitivity, there is no change to the rankings of the options on a weighted basis.

Figure 7.12: Weighted net benefits under 25 per cent higher network capital costs

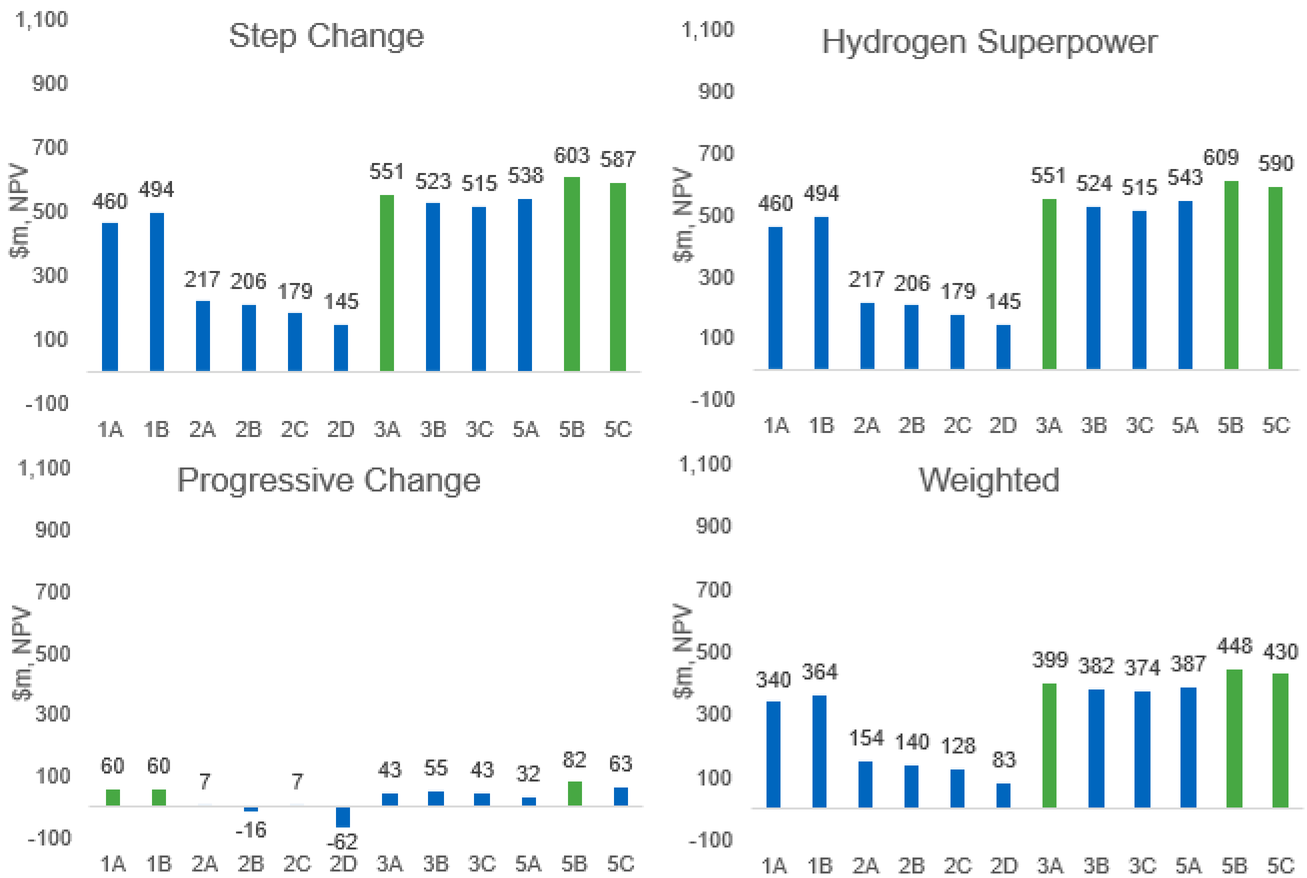


Figure 7.13 shows the results with 25 per cent lower network capital costs. Under this sensitivity, there is no change to the rankings of the options on a weighted basis.

Figure 7.13: Weighted net benefits under 25 per cent lower network capital costs

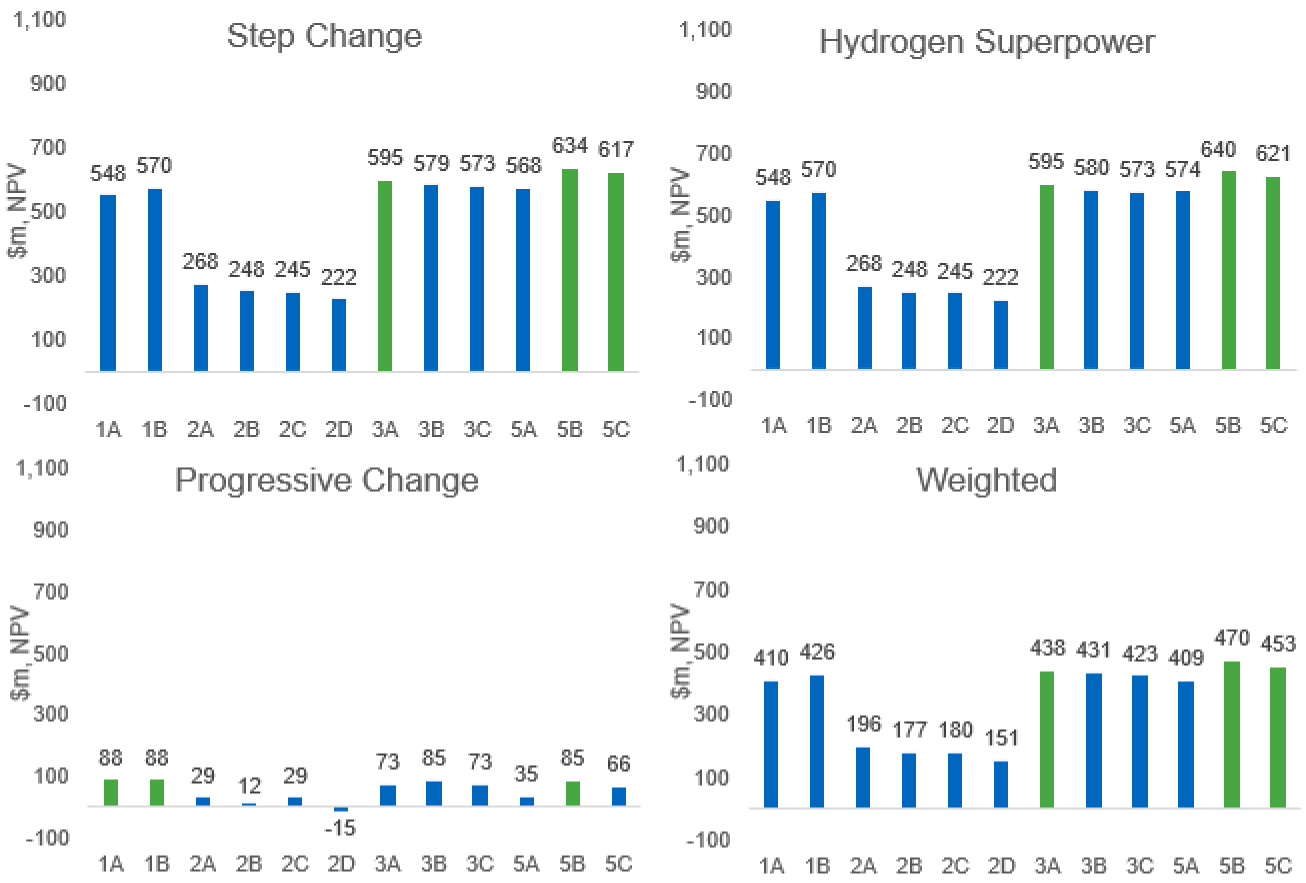


Figure 7.14 shows the results with 25 per cent higher non-network capital costs. In this sensitivity, Option 5B remains the highest ranked option, with net benefits $10 million (2 per cent) higher than Option 3A. The weighted net benefits of Option 5C are $8 million (2 per cent) lower than Option 3A.

Figure 7.14: Weighted net benefits under 25 per cent higher non-network capital costs

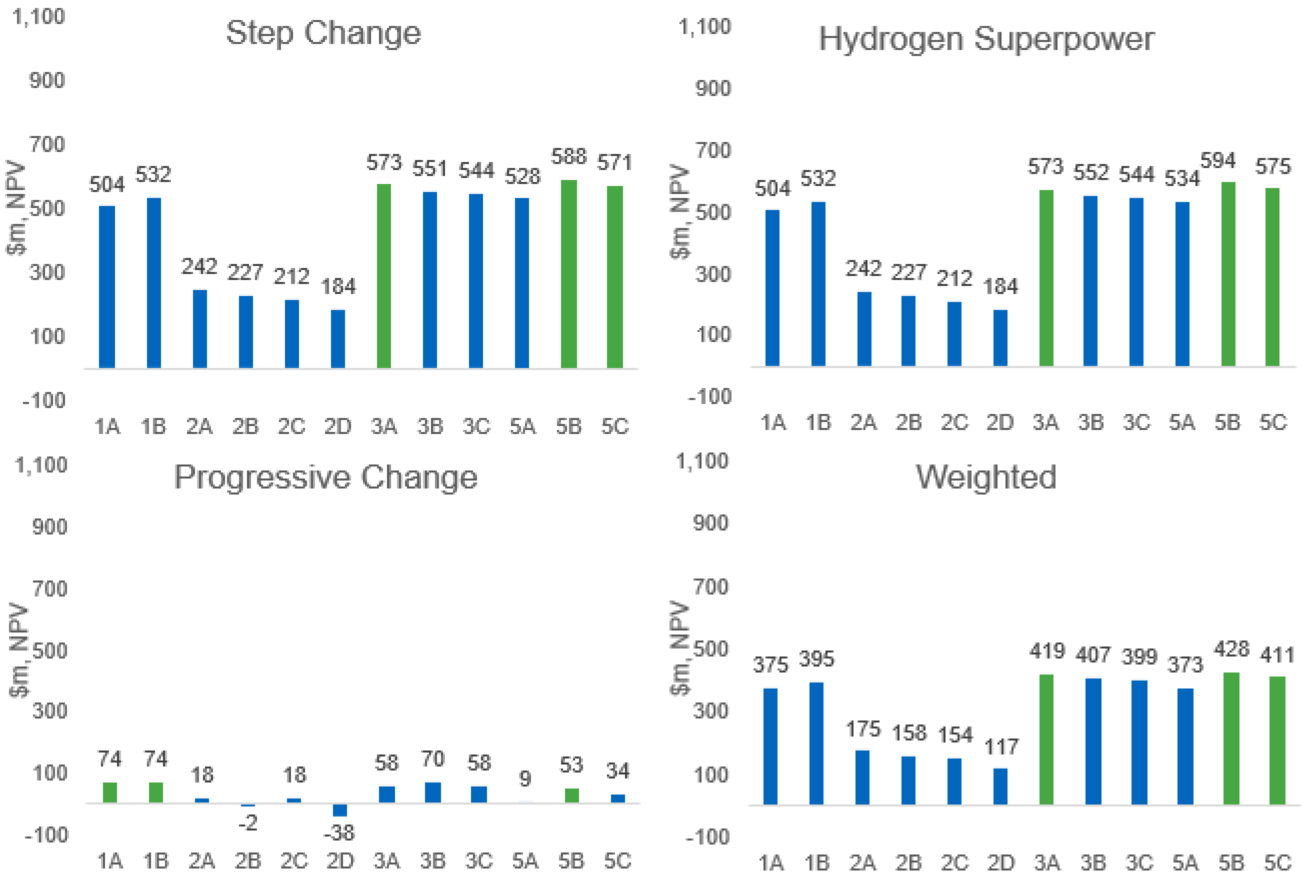
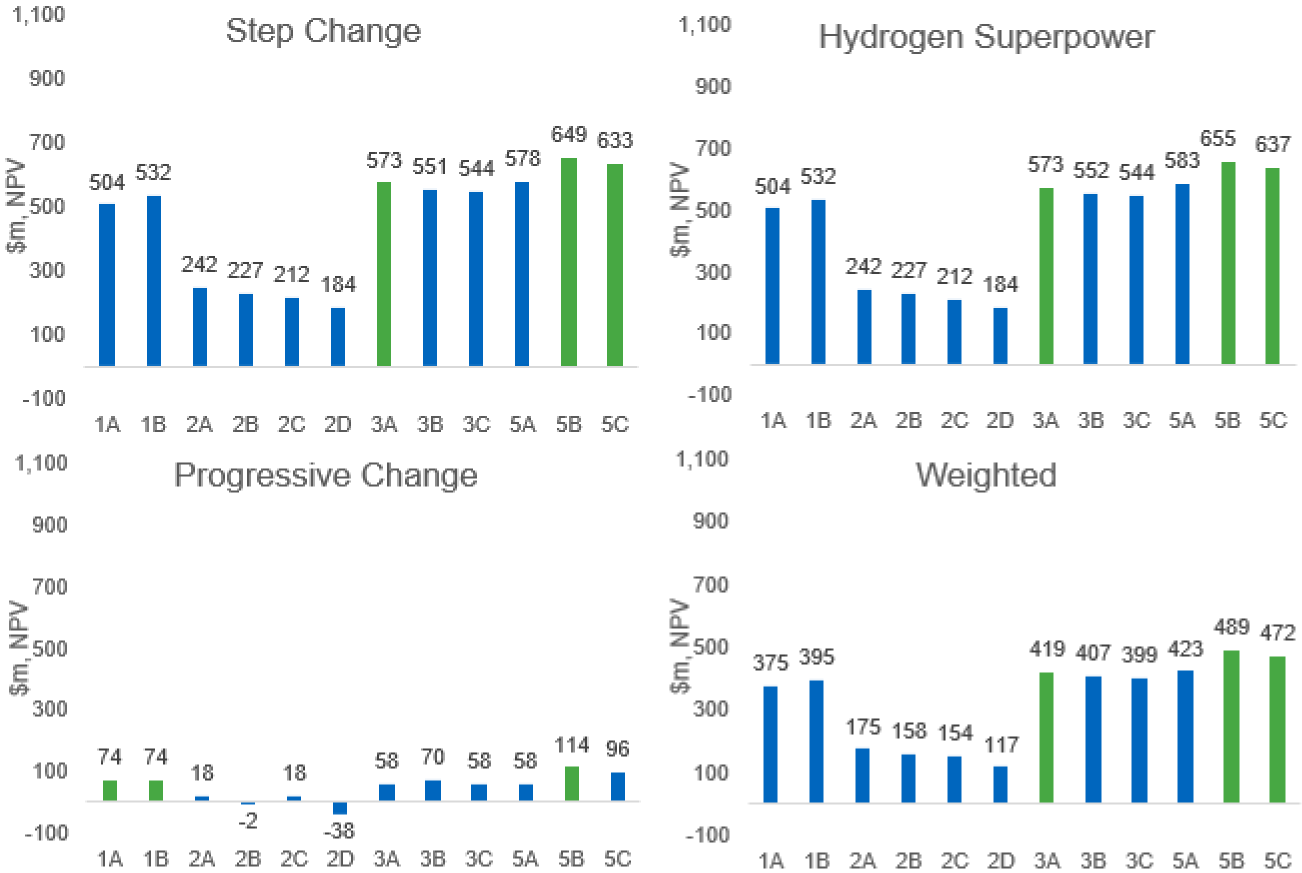


Figure 7.15 shows the results with 25 per cent lower non-network capital costs. In this case, Option 5B and Option 5C remain the highest two ranked options. However, Option 5A is now the third ranked option, marginally ahead of Option 3A ($4 million or 1 per cent).

Figure 7.15: Weighted net benefits under 25 per cent lower non-network capital costs



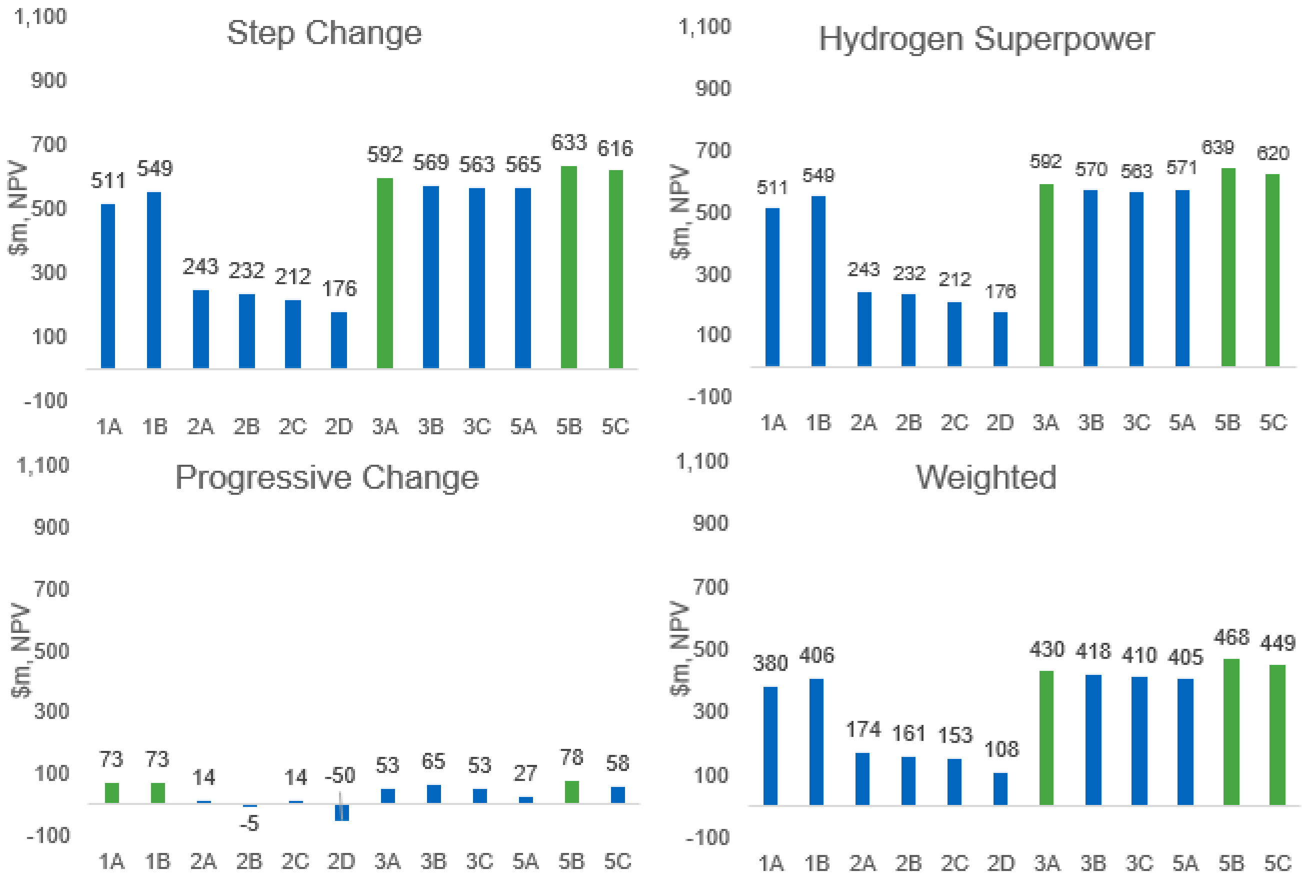
We have also extended this sensitivity and applied Transgrid's updated 2022 unit rate costs, updated from the 2021 unit rates as part of our annual cost estimating database update to capture the latest market pricing and observed cost movements. This aligns with our Revised Revenue Proposal for network capital costs (as well as also increasing non-network costs by the same proportion as the updated network costs). These updated unit rates: [66]

- reflect the high and unexpected inflation over the 12 months to June 2022, driven by a range of factors beyond our control; and
- are more recent and therefore provide the best available information for the purpose of forecasting future capex.

[66] Transgrid, 2023-28 Revised Revenue Proposal, December 2022, pp. 67-68.

Figure 7.16 presents the results for each scenario under the unit rate update with non-network costs increasing by the same proportion as the updated network costs. There is no change to the ranking of the options relative to the core results on a weighted basis.

Figure 7.16: Weighted net benefits under updated unit rates with proportional NNO cost increase



We have also undertaken boundary testing on the network capital costs. In relation to the highest ranked options (Options 5B and 5C):

- All network components of Options 5A – 5C are shared with Option 3A. Therefore, if the costs of those components change, then the rankings between Options 5A – 5C and Option 3A will not change.
- An increase of more than 106 per cent increase in the costs of the network components of Option 5C would make Option 1B preferred over Option 5C.
- An increase of more than 146 per cent increase in the costs of the network components of Option 5B would make Option 1B preferred over Option 5B.

Transgrid considers that changes in costs of this magnitude are unlikely, given the +/-25 per cent estimation accuracy adopted for the cost estimates.

In relation to the preferred network only option (Option 3A):

- An increase of more than 28 per cent (or $38.1 million) in the cost of all network components of Option 3A would be required to change the ranking of the credible network only options (ie, to make Option 1B preferred over Option 3A).

- In this case, Option 5B and Option 5C remain preferred to a network only option because of the benefit of avoiding USE sooner for options that have a non-network component.

Transgrid notes that factors leading to a change in the costs of Option 3A (such as manufacturing or materials cost increases) would also likely affect Option 1B in the same way, increasing its costs by a similar proportion. This is also a degree of similar scope between the components of Option 3A and Option 1B (i.e. the transformer and the upgrade to Line 9UH). As a consequence, Transgrid does not consider that an increase of more than 28 per cent for Option 3A without a similar increase in costs for Option 3B is a likely outcome.

7.5.4. The impact of different spot load forecasts

The primary source of market benefit for this RIT-T is avoided unserved energy in the North West Slopes region and so we have investigated sensitivities involving different demand forecasts outside of the central and low demand forecasts used in the core assessment.

If all anticipated spot load was removed from the forecasts, this would mean that that investment is not required. This highlights that the proposed investment is driven by the anticipated increase in key spot load.

We have also investigated the effect of removing the Narrabri Gas Project from the demand forecasts. Removal of the Narrabri Gas Project under the Progressive Change scenario means that investment would not be required.

Figure 7.17 presents the results of this sensitivity analysis in the Step Change scenario with avoided unserved energy zeroed out after 2028/29. Avoided unserved energy was zeroed out after 2028/29 in the PACR to improve the readability of results.

Figure 7.17: Net benefits under the Step Change scenario without the Narrabri Gas Project (avoided unserved energy after 2029 excluded)

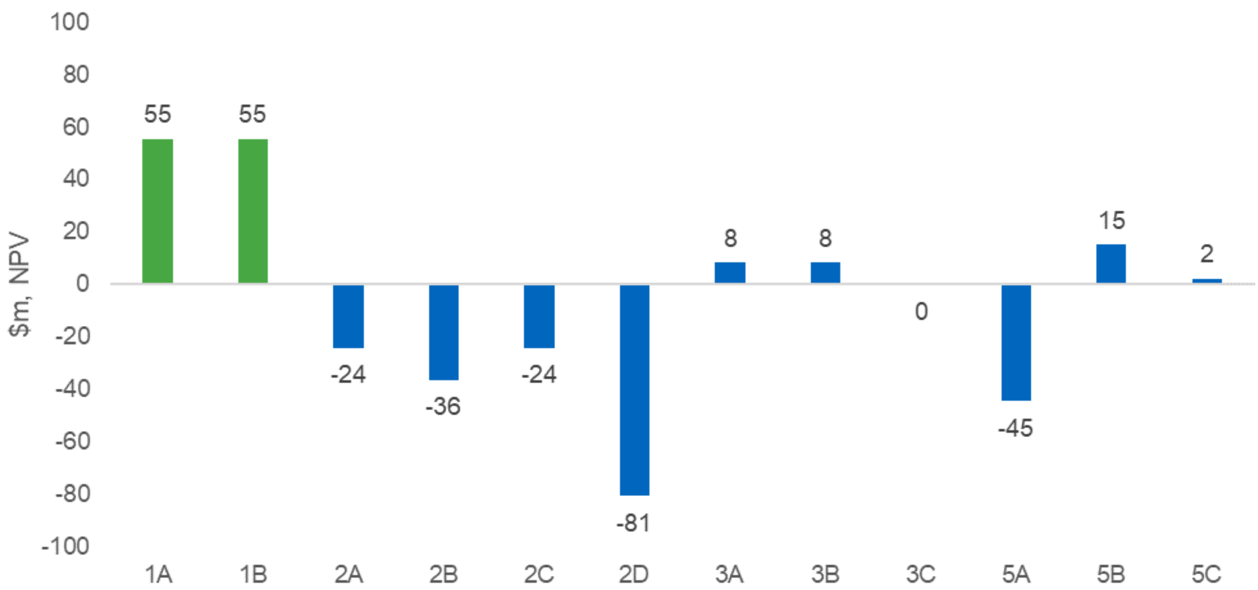
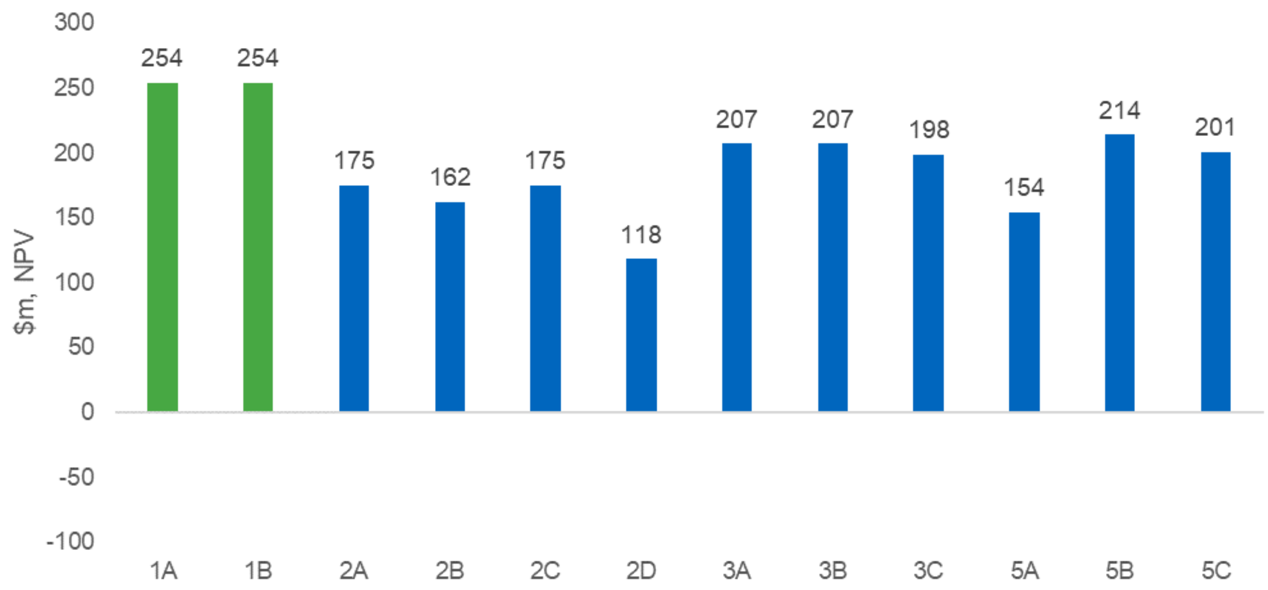


Figure 7.18 presents the results of this sensitivity analysis in the Step Change scenario with all avoided unserved energy benefits included.

Figure 7.18: Net benefits under the Step Change scenario without the Narrabri Gas Project (avoided unserved energy after 2029 included)



The results of this sensitivity under the Hydrogen Superpower scenario are almost identical to the Step Change scenario, with the net benefits of Option 5A, Option 5B and Option 5C increasing by between $2 million and $6 million, and the net benefits of all other options staying the same. This is because both scenarios use the same demand forecast and only vary to the extent that the wholesale market benefits differ.

The results show that under the Step Change and Hydrogen Superpower scenarios, Option 1 (ie, Option 1A or Option 1B) is the preferred option under a sensitivity in which the Narrabri Gas Project does not proceed. Option 1 involves building a 50 MVAr SVC at Gunnedah substation in 2025/26. This is the lowest cost option under this sensitivity. Option 1A and Option 1B are equivalent under this sensitivity.

The preferred options from the PACR, Option 5B and Option 5C, are still projected to deliver positive net benefits under this sensitivity, but of approximately $40 million and $53 million below Options 1A and 1B (the highest ranked options).

We note that the Progressive Change scenario (see section 7.2, above) includes only Stage 1 of the Narrabri gas project. In this scenario, Option 5B is the highest ranked option, ahead of Option 1A and Option 1B.

7.5.5. Scenario weightings

As is outlined above, Option 5B is the top ranked option on a weighted basis and in each scenario. This is a minor change from the initial PACR, where Option 5B was the top ranked option on a weighted basis and in the central and high economic benefits scenarios assessed at the time, but not in the low economic benefits scenario.

Option 5C is ranked above Option 3A in all scenarios but is ranked below Options 1A, 1B and 3B in the Progressive Change scenario. We find that the Progressive Change scenario would need to be weighted at least 88 per cent, with the other two scenario weighted relative to their ISP weights, for Option 5C to be ranked below a purely network option on a weighted basis (which we do not consider reasonable).

The findings of the amended PACR assessment mean that applying equal weightings (on the basis that there is no information as to whether one demand outcome is more likely than another), or the PADR '25:50:25' weights (as it could be argued that the central demand forecast has been constructed to be the more likely), do not change the conclusion of this RIT-T, i.e., that Option 5B and Option 5C are ranked effectively equal first overall. This is illustrated in the two figures below.

Figure 7.19 presents the results of applying equal weightings to each of the Step Change, Progressive Change and Hydrogen Superpower scenarios.

Figure 7.19: Weighted net benefits applying equal weighting to each scenario

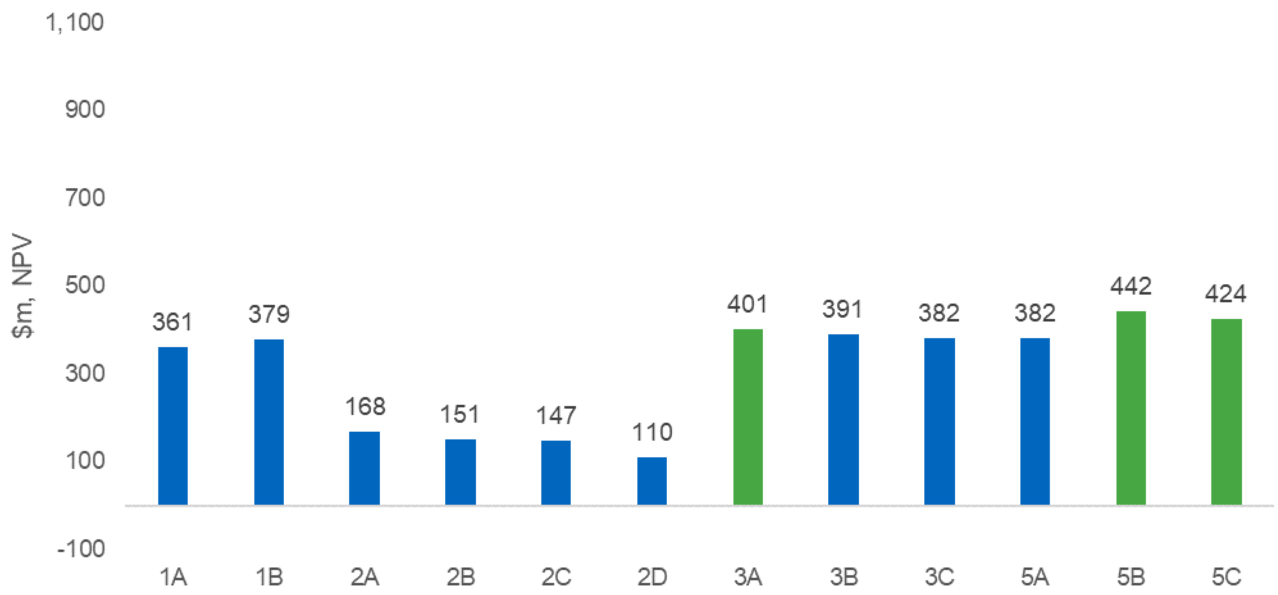
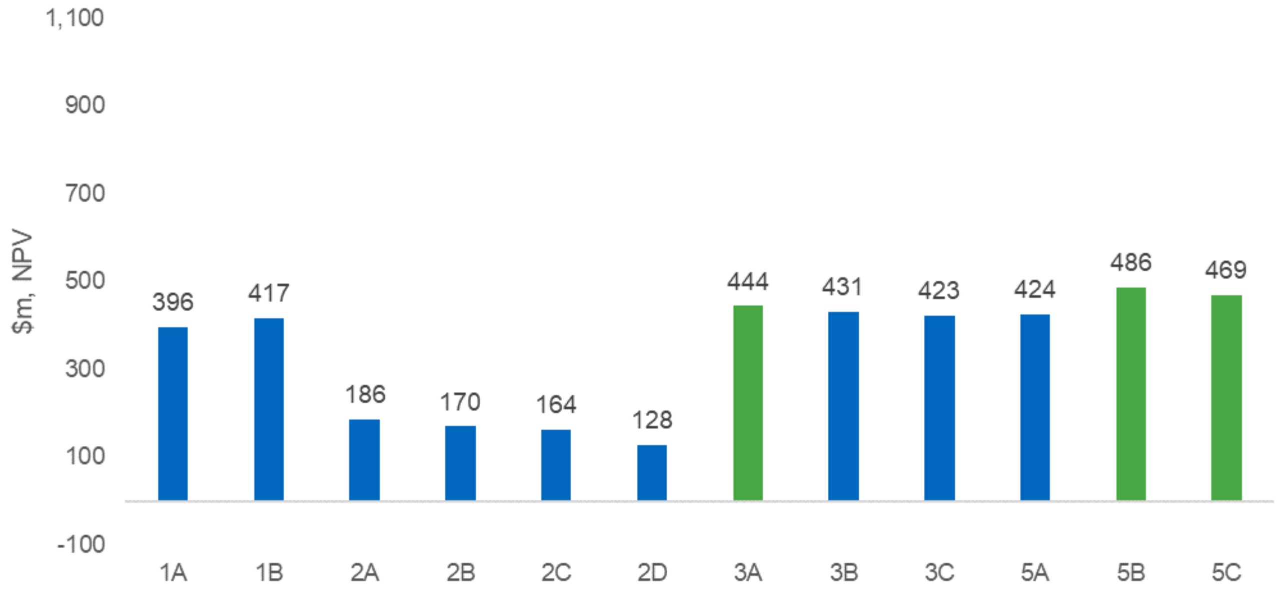


Figure 7.20 presents the results of using ’25:50:25’ weighting, in line with the PADR.

Figure 7.20: Weighted net benefits applying the PADR ’25:50:25’ weighting



7.5.6. Assumed timing of the network and non-network components

As outlined in section 7.4, a key determinant of the overall preferred option in this RIT-T assessment is the assumed build times, and ultimate commissioning dates, of each of the credible options, since options that can be commissioned sooner allow for substantial amount of unserved energy to be avoided.

While the commissioning dates for each option have been estimated using our, and third party (where relevant), best endeavours at this point in time, we have also investigated a range of sensitivities that relax these assumptions to see how the overall conclusion of the assessment is affected.

The table below investigates the effects of assuming earlier commissioning dates for the top-ranked solely network option (Option 3A) as well as assuming later commissioning dates for the top-ranked options involving non-network components (Option 5B and Option 5C). Specifically, Table 7.1 shows the net market benefits under various alternate timing assumptions, with red text denoting the top-ranked option (and any other option within 5 per cent of the top-ranked option).

Table 7.1: Alternate timing sensitivities ($m, NPV), weighted

	Option 3A	Option 5B	Option 5C
Core result	419	459	441
Option 3A one year forward	466	459	441
NNO one year delay	419	461	444
NNO two year delay	419	377	360
Option 3A forward and NNO delay	466	461	444

Red text denotes the preferred option and any option within 5 per cent of the preferred option

While the table above shows that bringing forward Option 3A by one year results in it having effectively the same net benefits as Option 5B and Option 5C, we do not consider this feasible and, at most, consider this option could be expedited by six months.

The table above also shows that Option 5B and Option 5C still remain ranked marginally above Option 3A if they were to be deferred by a year. This result is driven by the additional year of discounting for the BESS capital costs marginally outweighing the avoided unserved energy at the start of the assessment period. However, we note that a further year delay would severely decrease the estimated net benefits of these options (due to the significant unserved energy in the base case for that year) and result in Option 3A being uniquely preferred.

8. Conclusion

The preferred option identified in this amended PACR remains unchanged from the initial PACR and involves a non-network solution provided through a BESS at the Gunnedah 132 kV substation and the installation of a third 60 MVA 132/66 kV transformer at Narrabri 132/66 kV substation in the near-term. It also involves the rebuilding of the existing 969 line between the Tamworth 330 kV and Gunnedah substations as a double circuit line and upgrading the 9UH line between Narrabri and Boggabri North to a rating of 100 MVA over the longer-term, depending on outturn demand forecasts.

The proposals of two separate third party non-network BESS proponents have been found to be ranked effectively equal in the PACR assessment. These options are referred to as Option 5B and Option 5C in the PACR, and reflect the proposed BESS component followed by the network investment outlined above. These options are found to deliver approximately $459 million and $441 million in net benefits, respectively, relative to the 'do nothing' base case on a weighted basis, which compares to $419 million for the preferred solely network option (Option 3A).[67] The proposal of the third BESS proponent (assessed as Option 5A) has been found to deliver lower net benefits than these two options but to effectively be ranked equally with Option 3A.

We will now enter into a competitive procurement process and commercial negotiations with non-network proponents for a network support contract and seek to put in place a contract with one of these parties. We consider these negotiations should involve all proponents involved in the RIT-T process (i.e., including Option 5A, which has lower estimated net benefits than the other two non-network options) and potentially others who are able to provide the same kind of solution within the required timeframe, since the timing of when BESS can be implemented is critical to which solution is ultimately preferred (and may be able to be refined through the negotiation process). In addition, we consider that having more parties involved in this process will ensure that the network support costs paid for by consumers are as efficient as possible.

Notwithstanding the above, we consider that if either of the following two events occur, they would likely constitute a 'material change in circumstances' (i.e., under clause 5.16.4(z3) of the NER):

1. None of the non-network proponents being able to commit to having the BESS in place to provide network support by a date that ensures that option continues to be considered as the top-ranked option under the RIT-T; or

2. Transgrid not being able to finalise a network support contract with any of the proponents that is expected to be accepted as prudent and efficient by the AER.

Should either (or both) of these events occur, we would seek an exemption from the AER under clause 5.16.4(z3) of the NER to avoid having to reapply the RIT-T. Specifically, we consider that, should either of the above events occur, then the analysis presented in this PACR demonstrates that Option 3A (i.e., the top ranking solely network option) should then be considered the preferred option under this RIT-T.

We consider this approach provides sufficient confidence that Transgrid will be able to progress an option to ensure the externally-imposed regulatory obligations and service standards this RIT-T is designed to meet are met at an efficient cost level without having to re-do the RIT-T. We note that re-doing the RIT-T would take significant time, which would compromise the reliability of supply to customers in the North West Slopes area and ultimately likely cost all NSW electricity customers more in the long-run.

[67] Option 3A includes an additional network component to Options 5A-5C, as well as earlier investment in some components.

We note that the NER regarding a 'material change in circumstances', and the ability to include 'reopening triggers'[68] in a PACR have recently been considered by the Australian Energy Market Commission.[69] The final rule requires RIT-T proponents of projects with an estimated cost of more than $100 million to develop reopening triggers that clearly indicate whether there has subsequently been a material change in circumstances following completion of the RIT-T.[70] While the new rule requirements do not apply to this RIT-T, consistent with the final rule made, we consider the events above to constitute two elements of an effective reopening trigger for this RIT-T.

We will update stakeholders when we consider that the network support agreement for one of these options is sufficiently certain, or at the point we determine there has been a material change in circumstances and that the investment should be progressed as a solely network option (i.e., Option 3A) (i.e., when we would submit an exemption to the AER from having to reapply the RIT-T).

Our recently submitted Revised Revenue Proposal for the 2023-2028 period includes ex ante augmentation capital expenditure for this project in the forthcoming regulatory period associated with the installation of a new transformer at our Narrabri substation (which is required in 2025/26 irrespective of the demand forecast or preferred option in this PACR). We have also included a nominated pass through event and contingent project to address the risk that no non-network proponents are able to commit to provide the service in the required timeframe, as well as a separate contingent project covering potentially upgrading the existing transmission lines in the area because the timing is uncertain and dependent on future demand growth becoming committed (in particular the Narrabri Gas Project). More information on our 2023-28 Revised Revenue Proposal can be found here.

We consider that the preferred option, as defined above, satisfies the RIT-T.

68 We note that what was originally referred to as 'decision rules' at the time of the initial PACR has been relabelled as 'reopening triggers' by the AEMC to differentiate this approach from the decision rules AEMO uses for the ISP. See AEMC, *National Electricity Amendment (Material Change in Network Infrastructure Project Costs) Rule*, Rule Determination, 27 October 2022, p. 9.
69 AEMC, *Transmission Planning and Investment Review*, Consultation Paper, 19 August 2021, p. 54.
70 AEMC, *National Electricity Amendment (Material Change in Network Infrastructure Project Costs) Rule*, Rule Determination, 27 October 2022, p. ii.

Appendix A Compliance checklist

This section sets out a compliance checklist which demonstrates the compliance of this PADR with the requirements of clause 5.16.4 of the National Electricity Rules version 194.

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 Appendix E
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;	3
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	4 & 7
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	6 & Appendix F
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	6.6
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	7
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	7
	(8) the identification of the proposed preferred option;	8
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	8

Appendix B Overview of existing electricity supply arrangements in the North West Slopes area

The North West Slopes area covers loads from Tamworth to Moree. The area is primarily supplied by 132 kV lines from the Tamworth 330/132 kV substation:

- Line 968 – Tamworth to Narrabri; and
- Line 969 – Tamworth to Gunnedah.

This part of the network is parallel to the 330 kV main system that interconnects the NSW and Queensland systems. Power flows on lines 968 and 969 are therefore affected by power flows on the NSW/Queensland interconnectors QNI and Directlink. At times of heavy power flows between the two states, the power flows on lines 968 and 969 can be significantly impacted by these main system flows.

The Narrabri and Gunnedah 132/66 kV substations supply Essential Energy loads in the area, with each substation having two 60 MVA 132/66 kV transformers. The Boggabri Coal and Maules Creek mines are also connected to the TransGrid 132 kV network via the Boggabri East and Boggabri North switching stations.

The current northern NSW electricity transmission network is shown in in Figure B. 1 below with the area relevant for this RIT-T (the North West Slopes area) circled. The indicative location of the key forecast electricity loads that are discussed in this PACR (and are publicly announced) are also shown.

Figure B. 1: Northern NSW transmission network

Electricity demand in the North West Slopes is forecast to increase significantly over the next ten years, primarily due to planned connections of new mining and industrial loads in the area.

Electricity demand from expected new mining loads

VCM was approved by the Independent Planning Commission of NSW in August 2020 and is expected to be connecting to the distribution network. The project is located in the Gunnedah Coalfield, which is approximately 25 km north of Gunnedah.[71]

The scope of the VCM project includes the construction of a new 66 kV/11 kV substation that would be serviced by an existing 66 kV overhead powerline.[72] In light of the project's location, it will likely be supplied by Transgrid's Gunnedah 132/66kV substation. This new additional load is expected to require supply from late 2024,[73] with maximum electricity demand when fully operational of approximately 62,700 MWh per annum.[74]

We were advised in a submission to the PADR that the Narrabri Coal expansion project was approved by the Independent Planning Commission in April 2022. This additional load for the existing Narrabri Coal Mine is expected to require increased supply from the final quarter of 2024, with maximum electricity demand of 32.8 MW in the first quarter of 2030. While this load was not included in the 2021 TAPR, it is will be in the forthcoming 2022 TAPR.

Essential Energy has also advised that Santos NSW (Eastern) Pty Ltd is proposing to develop the Narrabri Gas Project. The project canvasses connecting to the NSW power grid by drawing power from the existing Wilga Park Power Station via a new power distribution line.[75] As a result, it would be supplied from Transgrid's Narrabri 132/66 kV substation. This is not included in Essential Energy's base demand forecast. The specific load forecasts for this project have not been included in this PACR due to confidentiality reasons.

The Narrabri Gas Project has received development consent from the Federal Government,[76] contingent on a number of environmental conditions being met. Santos has announced that this approval will allow them to begin an appraisal program ahead of a Final Investment Decision (FID) for the next phase of project development.[77] The FID date is currently scheduled for first half 2023 and, once approved, Stage 1 of production will require supply from 2026.[78]

The development of a pipeline that links the Narrabri project to the existing Moomba to Sydney Pipeline is being investigated by the APA group.[79] The proposed route would commence to the north of the Pilliga National Park and Pilliga West State Conservation Areas, before extending west-southwest to connect to the Moomba to Sydney Pipeline at the Bundure mainline valve station, approximately 100 km west of

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71 Australian Mining Monthly, *Vickery extension on track for 2021 construction completion,* 8 June 2019, available at: https://www.miningmonthly.com/development/international-coal-news/1364804/vickery-extension-on-track-for-2021-construction-completion; and Whitehaven Coal, *Vickery Extension Project Environmental Impact Statement* | *Introduction*, p 1-1, available at: https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=SSD-7480%2120190303T213410.742%20GMT.

72 Whitehaven Coal, *Vickery Extension Project Environmental Impact Statement* | *Project description*, p 2-18, available at: https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=SSD-7480%2120190303T213412.005%20GMT

73 This has been updated since the PADR, when 2023 was the expected commencement date.

74 Whitehaven Coal, *Vickery Extension Project Environmental Impact Statement* | *Project description*, p 2-31, available at: https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=SSD-7480%2120190303T213412.005%20GMT

75 Santos, *Narrabri Gas Project Environmental Impact Statement* | *Project description,* p 6-18, available at: https://majorprojects.accelo.com/public/1e6475194c440a225a59dddcb004fd53/Chapter%2006%20Project%20description.pdf

76 NSW planning portal website, https://www.planningportal.nsw.gov.au/major-projects/project/10716

77 Santos' Narrabri Gas Project website, https://narrabrigasproject.com.au/2020/11/santos-welcomes-federal-signoff-on-narrabri-gas-project/

78 Santos 2020 Investor Day 1 Dec 2020, available as "Santos upgrades 2020 guidance" at: https://www2.asx.com.au/markets/company/STO

79 APA group website project updates, https://www.apa.com.au/about-apa/our-projects/western-slopes-pipeline/project-updates/

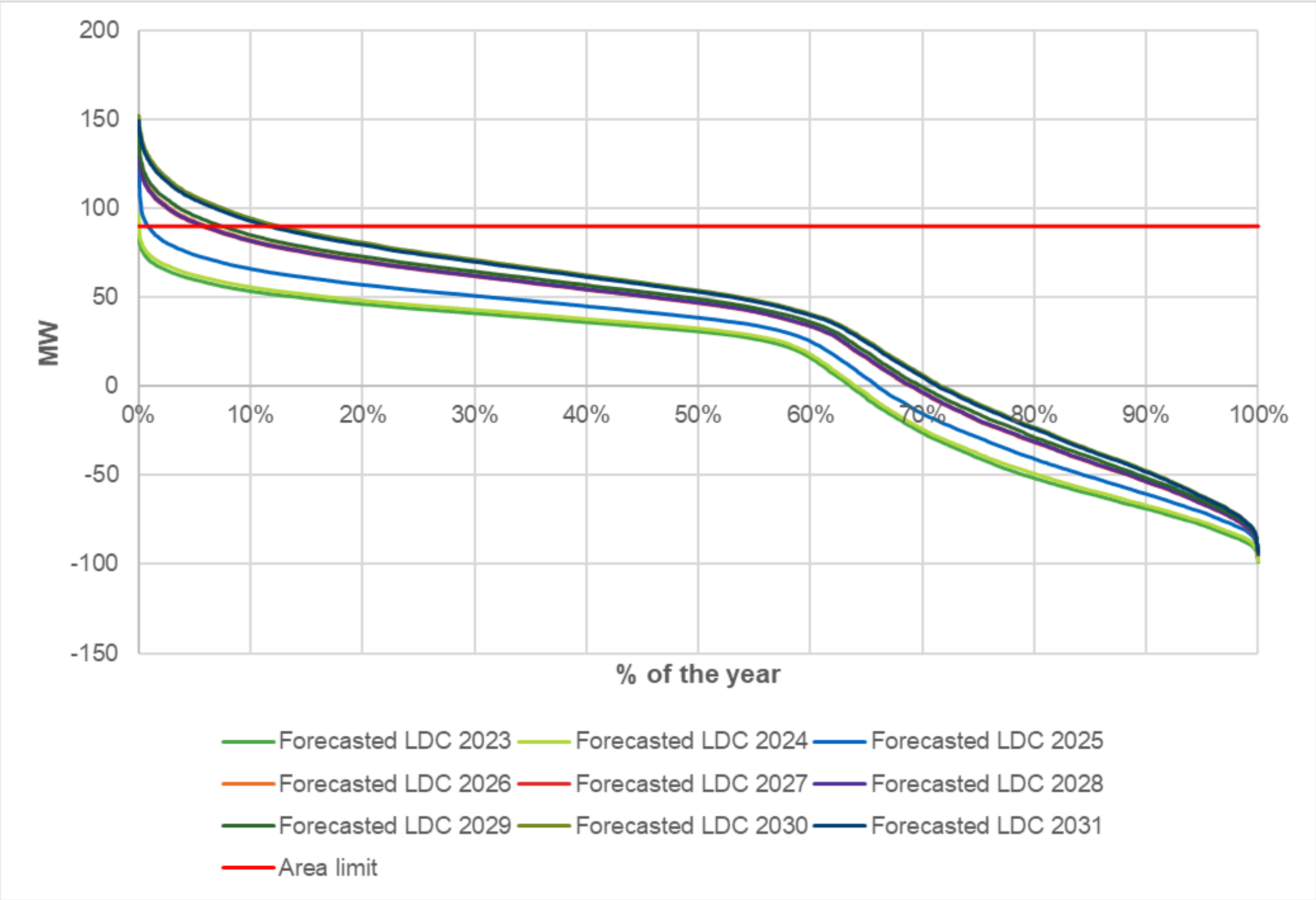
Condobolin. Should this gas pipeline not be installed, it may affect the ability to fully develop the Narrabri Gas Project (which in-turn has implications for the certainty of the electricity demand projections).

General system demand in the North West Slopes area

We forecast there to be steady load increases for the North West Slopes area over the next twenty years, with Narrabri having the greatest expected load increase.

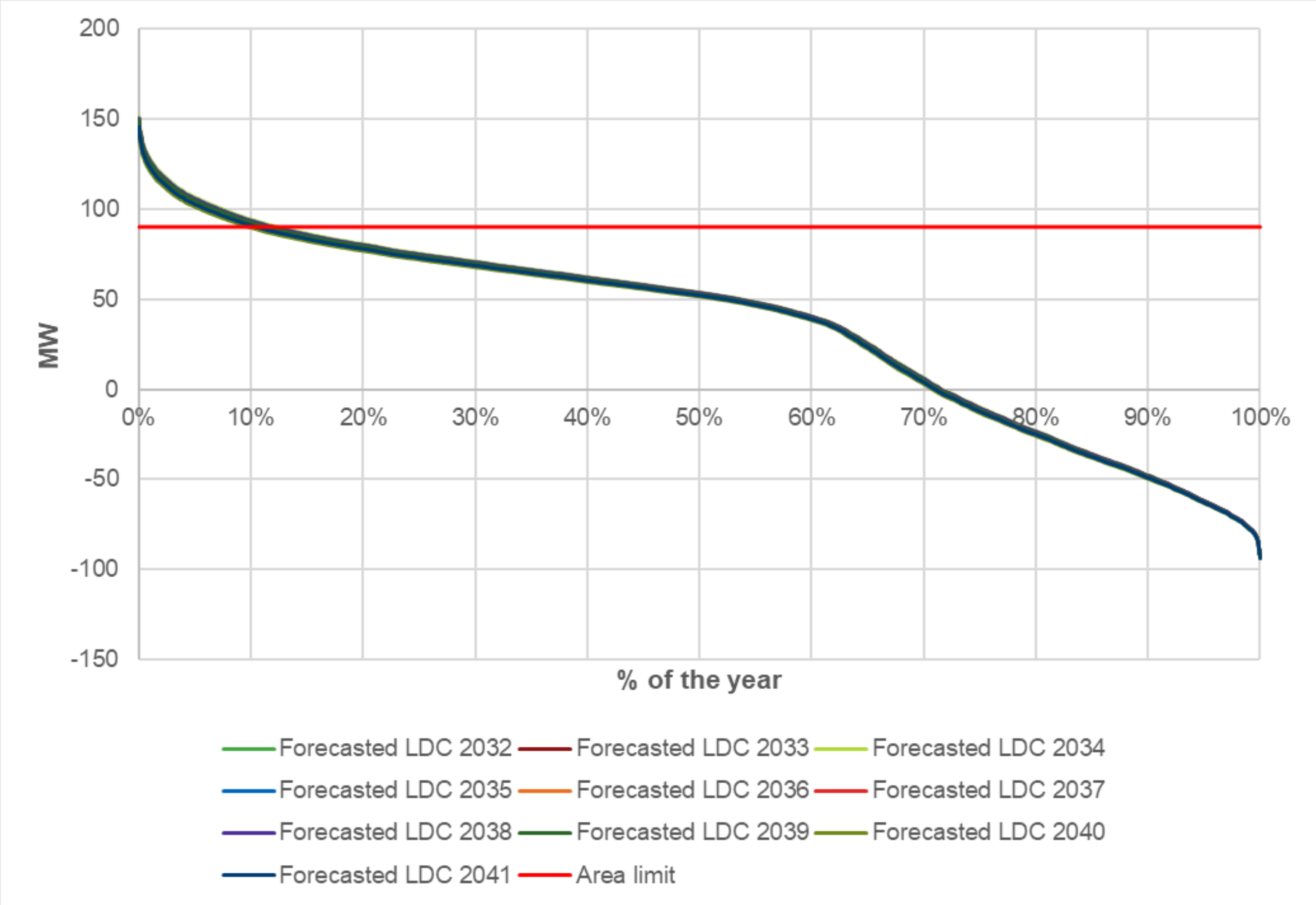
The two figures below present the actual 2019, as well as the forecast future, load duration curves (LDCs) and demand limits for the Narrabri and Gunnedah 66 kV BSP along with the existing and forecast mining loads under the central demand forecast. The LDCs represent the net demand (i.e., total demand minus committed embedded renewable generation in the area) and show the significant expected increase in demand going forward under the central forecast, as well as how the thermal and voltage limits are expected to be exceeded an increasing percentage of the year if action is not taken. This data provides a visual representation of the load that could be at risk during a calendar year under the central demand forecast if action is not taken.[80]

Figure B. 2: Forecasted LDCs and demand limits for the North West Slopes area to 2031 under the central demand forecasts



[80] The data shown in these LDCs is the aggregate of the load at Narrabri 66 kV, Boggabri North 132 kV, Boggabri East 132 kV and Gunnedah 66 kV, less the Gunnedah Solar Farm generation.

Figure B. 3: Forecasted LDCs and demand limits for the North West Slopes area, forecast 2032 to 2041 under the central demand forecasts



Renewable generation in the region

In addition to the longer-term voltage constraints, the forecast increased demand going forward is expected to also lead to thermal constraints, particularly at times of low renewable generation dispatch in the region.

There are a number of in-service and planned renewable generator connections in the northern NSW region. Table B. 1 summarises these systems. The status of these has developments not changed since the initial PACR.

Table B. 1: Current and planned renewable generation in the northern NSW region

Generating System	Connection location	Capacity (MW)	Status
Moree Solar Farm	Essential Energy's 66 kV Moree network	56	In-service
White Rock Wind and Solar Farm	White Rock substation	172.5	In-service
Gunnedah East Solar Farm	9U3 Gunnedah to Boggabri East 132 kV line (close to Gunnedah)	110	In-service
Tamworth Solar Farm	969 Tamworth to Gunnedah 132 kV line	65	Advanced*

**'Advanced' connection is in the connection application process with the connecting NSP.*

We note that there are also other new potential renewable energy generation projects proposed in the area that are not yet at a committed or advanced stage.

Additional renewable generation could assist with addressing/minimising the identified need as it can provide reactive support while generating active power subject to its voltage control strategy. We have taken account of in-service and committed renewable generation in assessing the identified need for this RIT-T.

Appendix C Additional detail as to the basis for including potential spot loads in the analysis

The table below summarises all key loads in the area and the rationale for including them in the spot load forecasts used in this amended PACR (and the initial PACR).

While some have had to be redacted due to confidentiality reasons, the detail regarding all load forecasts has been shared in-confidence with the AER in its role of overseeing the RIT-T and ensuring the efficiency of any ultimately proposed expenditure.

Overall, in preparing this PACR (and the initial PACR), we have engaged with load proponents on the commitment status for key potential loads. Specifically, we have sought to corroborate the forecasts provided by proponents through having them provide additional information as to how each load is considered to meet the RIT-T criteria for being considered 'committed' or 'anticipated'. In some instances, we have relied on how Essential Energy have treated, or suggest treating, particular loads based on their more detailed understanding of the commitment status of these loads. Both processes have been instrumental in how each potential load has been factored into the analysis, as outlined in the table below.

Table C. 1 – Additional detail on the basis for including forecast spot loads in the assessment

Load	Load area	Included in the low demand forecast?	Included in the central demand forecast?	Number of RIT-T criteria for 'committed' or 'anticipated' met	Comment
Narrabri Gas Project	Narrabri	Yes, Stage 1	Yes, Stage 1 and 2	3+	The load is considered 'anticipated' based on the material provided by the proponent. We understand that the relevant government approvals have been received for the project, [redacted] Stage 1 is included in the low demand forecast due to the project being identified by the NSW Government as a 'strategic energy project' for the state with natural gas further identified as critical for energy security and reliability in NSW (and the Narrabri Gas Project committing 100 per cent of its gas to the domestic market).[81] [redacted]

[81] NSW Government, *Narrabri Gas Project – State significant development*, June 2020, pp iv and x.
[82] See Santos website, available at: https://www.santos.com/news/santos-acquires-hunter-gas-pipeline-pty-ltd-to-get-narrabri-gas-to-domestic-market-as-soon-as-possible/.

Load	Load area	Included in the low demand forecast?	Included in the central demand forecast?	Number of RIT-T criteria for 'committed' or 'anticipated' met	Comment
Narrabri Coal	Narrabri	No	Yes	3+	The load is considered 'anticipated' with the relevant approvals received for the project and so is included in the central demand forecast. However, its full commitment level is currently unknown, with Federal approval not yet received, and so it is not included in the low demand forecast.
Vickery Coal	Gunnedah	No	Yes	3	The load is considered 'anticipated' and is included within the central demand forecast. However, it is not included in the low forecast since it is not yet considered 'committed'.
Confidential industrial load	Gunnedah	No	Yes	NA	This is a small load in Essential Energy's network. Since it is included in their demand forecast, we have included it in our central demand forecast. However, on account of us not having received sufficient information for it to be considered 'anticipated' or 'committed' at this stage, it was removed for the low forecast.
Narrabri SAP	Narrabri	No	No	NA	This is not included as is deemed to not be in an advanced state yet.
Moree SAP	Moree	No	No	NA	This is not included as is deemed to not be in an advanced state yet.

Appendix D Additional detail on the methodology used to estimate capital costs

Our cost estimates for all credible options presented in this amended PACR (and the initial PACR) have been prepared in accordance with the Augmentation Expenditure ('Augex') Overview Paper submitted with our 2023-28 Revenue Proposal.[83] Section 7 of that paper outlines in detail our forecasting method, inputs, models and assumptions, including on unit costs, cost escalation and overheads (see sections 7.6, 7.7 and 7.8 of the Revenue Proposal Augex Overview Paper).

In summary, the cost estimates are developed using our 'MTWO'[84] cost estimating system. This system utilises historical average costs, updated by the costs of the most recently implemented project with similar scope. All estimates in MTWO are developed to deliver a 'P50' portfolio value for a total program of works (ie, there is an equal likelihood of over- or under-spending the estimate total). In accordance with industry best practice, the cost estimates consist of a base estimate and a P50 allowance lump sum.

For an Option Feasibility Studies (OFS) cost estimate, which is the level of estimate used in this PACR, the level of scope development and maturity of design inputs results in a cost estimate with an accuracy of +/-25 per cent. This is consistent with our Prescribed Capital Investment Process, which has been provided to the AER as part of the PIAC dispute process (along with a range of other confidential material relating to the cost estimation process). An accuracy of +/-25 per cent is consistent with industry best practice and aligns with the accuracy range of a 'Class 4' estimate, as defined in the Association for the Cost Engineering classification system.

All cost estimates are prepared in real, 2020-21 dollars based on the information and pricing history available at the time that they were estimated. The cost estimates did not include or forecast any real cost escalation for materials.

Biodiversity costs and property allowances for transmission lines apply when an option requires a new easement and use of an existing easement that is modified does not require these costs. Biodiversity costs and property allowances have been estimated by subject matter experts who assess the transmission line locality, property market and environment to estimate a per kilometre rate for the transmission line easement which is used in the capital cost estimate.

While some component costs presented in Table 4.1 of this PACR include land costs and biodiversity offset costs, they have not been broken out separately to contain the table. However, the NPV model released alongside the PACR separates out these elements.

83 Available at: https://www.aer.gov.au/system/files/TransGrid%20-%20Augex%20Overview%20Paper%20-%2031%20Jan%202022-%20PUBLIC.pdf

84 MTWO is a virtual-to-physical 5D BIM enterprise solution, designed to bring together all stakeholders and workflows on a single, cohesive platform. Built upon a bespoke vertical cloud infrastructure supplied by Microsoft Azure, MTWO allows users to integrate and digitalise all project delivery processes in a complete end-to-end solution. More than 100 enterprise-wide modules are built into MTWO, with everything from 5D BIM virtualisation to scheduling, procurement, bidding and tendering on offer. RIB's iTWO cx project management software is also available as part of the MTWO solution.

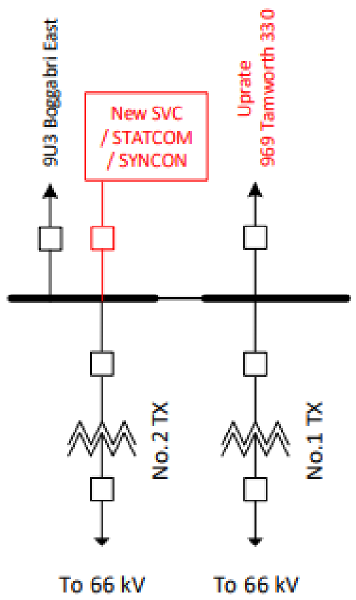
Appendix E Indicative line diagrams for each option

This appendix provides the line diagrams for each of the network elements of credible options considered in this PACR, as relevant. Existing elements are shown in black, while new elements are shown in red.

Option 1 – Uprating the existing line 969 from Tamworth to Gunnedah

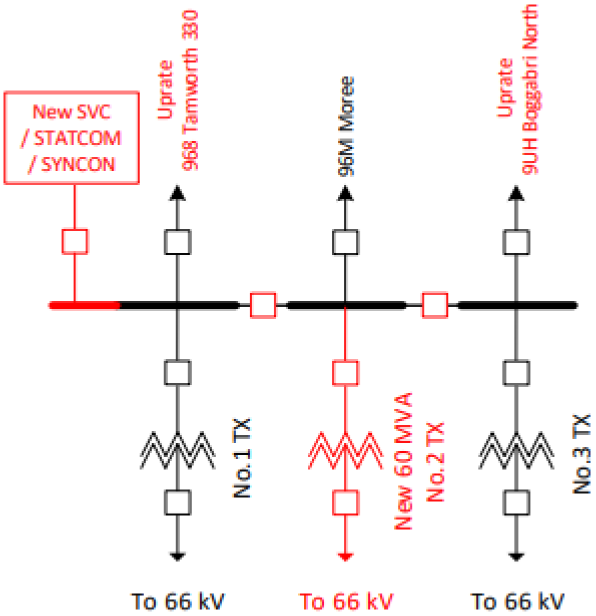
The indicative layout for the Gunnedah 132/66 kV substation under Options 1A and 1B is shown in Figure E-1 below.

Figure E-1: Indicative Gunnedah 132/66 kV substation layout under Options 1A and 1B



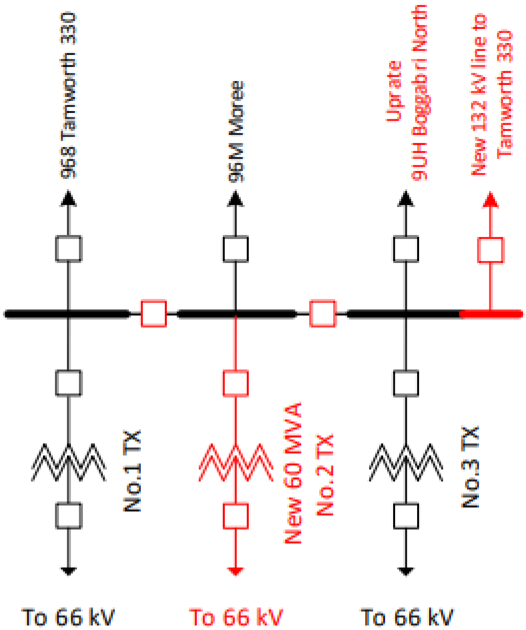
The indicative layout for the Narrabri 132/66 kV substation under Option 1A is shown in Figure E-2 below.

Figure E-2: Indicative Narrabri 132/66 kV substation layout under Option 1A



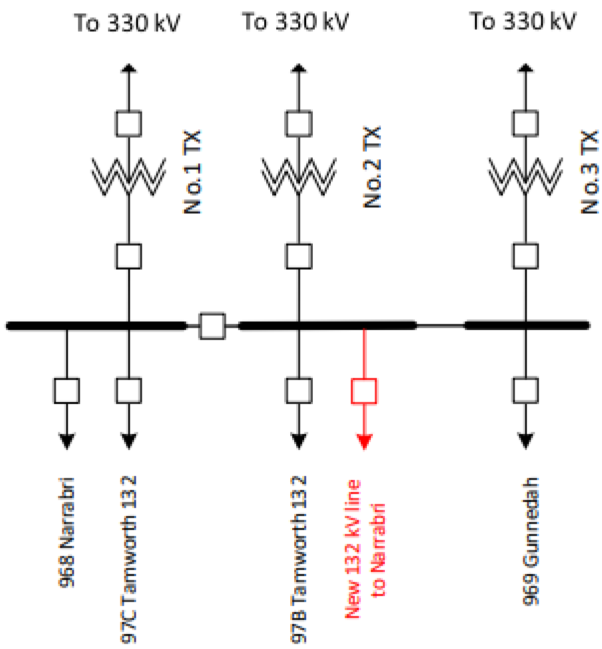
The indicative layout for the Narrabri 132/66 kV substation under Option 1B is shown in Figure E-3 below.

Figure E-3: Indicative Narrabri 132/66 kV substation layout under Option 1B



The indicative layout for the Tamworth 330/132 kV substation under Option 1B is shown in Figure E-4 below.

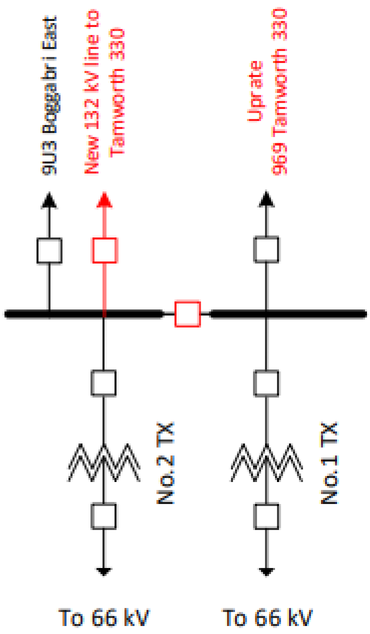
Figure E-4: Indicative Tamworth 330/132 kV substation layout under Option 1B



Option 2 – New single or double circuit transmission lines between Tamworth and Gunnedah

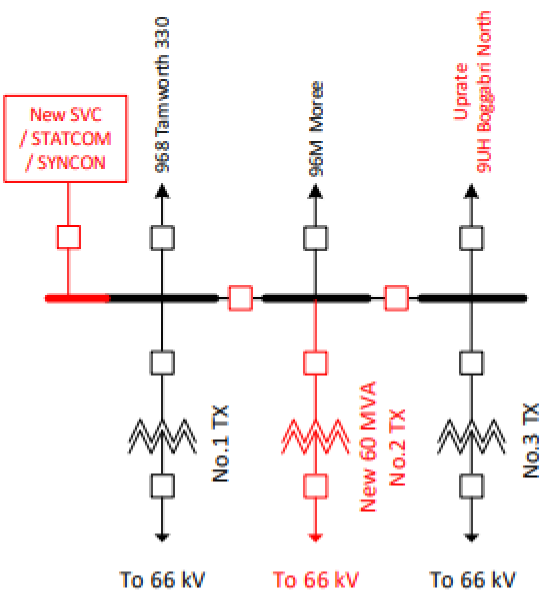
The indicative layout for the Gunnedah 132/66 kV substation under Option 2A is shown in Figure E-5 below.

Figure E-5: Indicative Gunnedah 132/66 kV substation layout under Option 2A



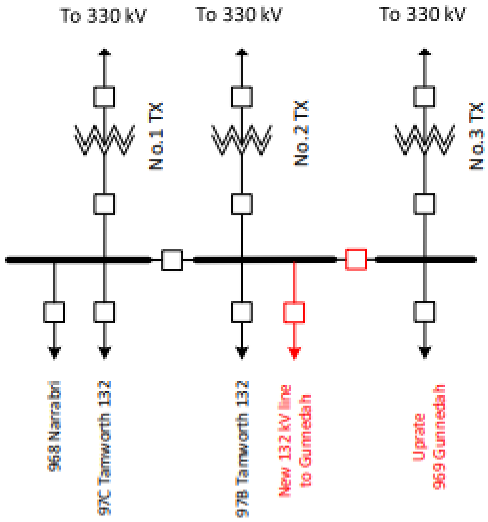
The indicative layout for the Narrabri 132/66 kV substation under Options 2A, 2B and 2D is shown in Figure E-6 below.

Figure E-6: Indicative Narrabri 132/66 kV substation layout under Options 2A, 2B and 2D



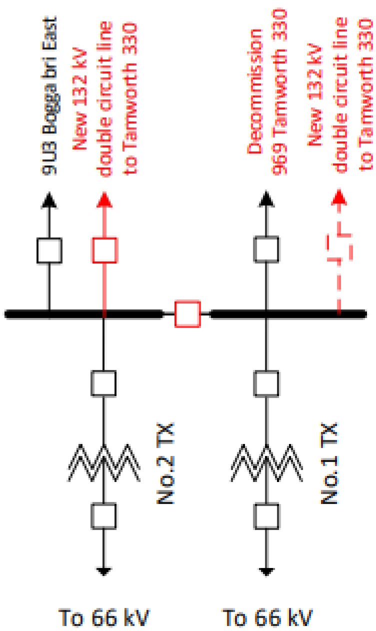
The indicative layout for the Tamworth 330/132 kV substation under Options 2A and 2C is shown in Figure E-7 below.

Figure E-7: Indicative Tamworth 330/132 kV substation layout under Options 2A and 2C



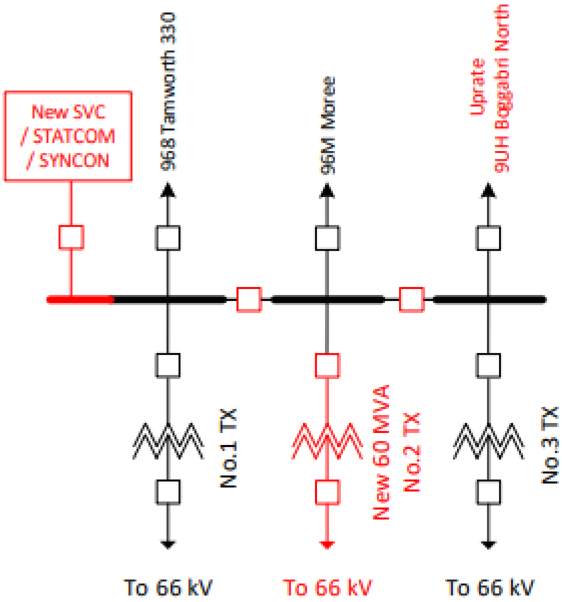
The indicative layout for the Gunnedah 132/66 kV substation under Option 2B is shown in Figure E-8 below.

Figure E-8: Indicative Gunnedah 132/66 kV substation layout under Option 2B



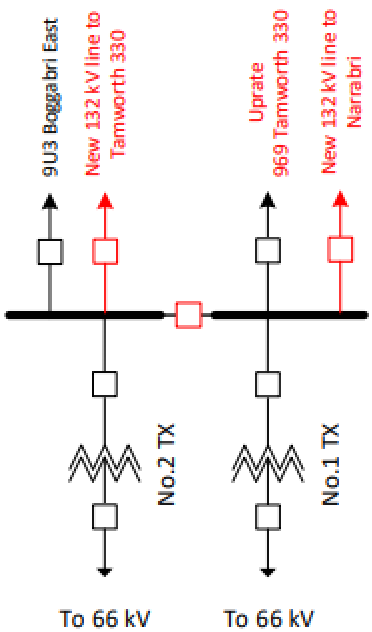
The indicative layout for the Tamworth 330/132 kV substation under Option 2B is shown in Figure E-9 below.

Figure E-9: Indicative Tamworth 330/132 kV substation layout under Option 2B



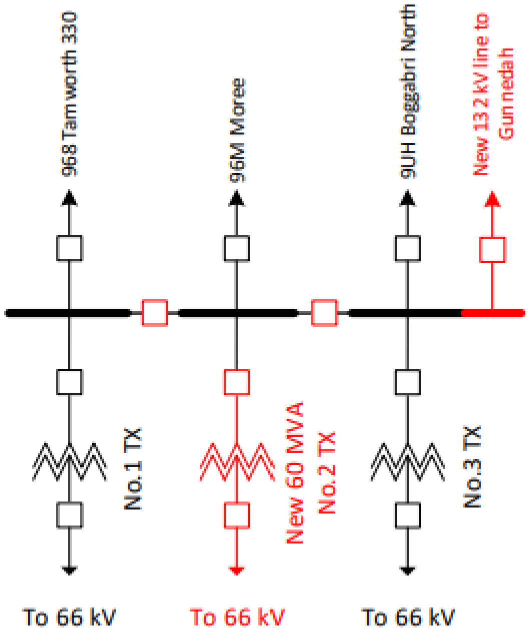
The indicative layout for the Gunnedah 132/66 kV substation under Option 2C is shown in Figure E-10 below.

Figure E-10: Indicative Gunnedah 132/66 kV substation layout under Option 2C



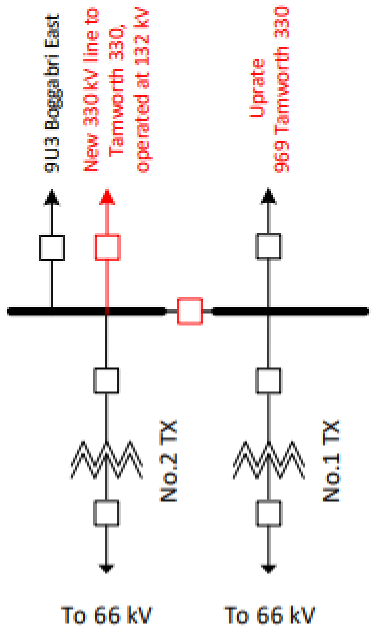
The indicative layout for the Narrabri 132/66 kV substation under Option 2C is shown in Figure E-11 below.

Figure E-11: Indicative Narrabri 132/66 kV substation layout under Option 2C



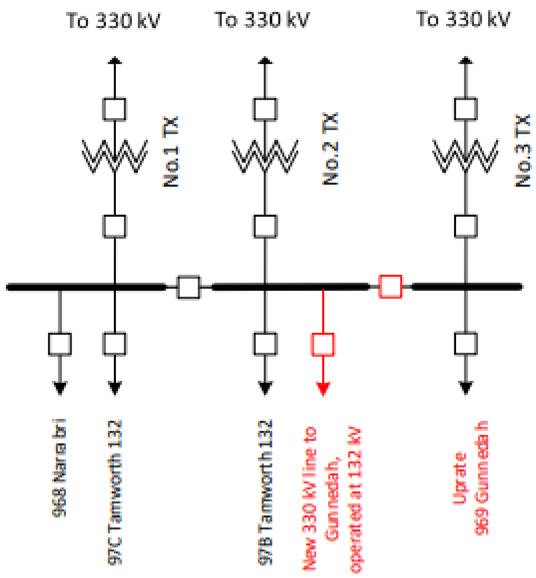
The indicative layout for the Gunnedah 132/66 kV substation under Option 2D is shown in Figure E-12 below.

Figure E-12: Indicative Gunnedah 132/66 kV substation layout under Option 2D



The indicative layout for the Tamworth 330/132 kV substation under Option 2D is shown in Figure E-13 below.

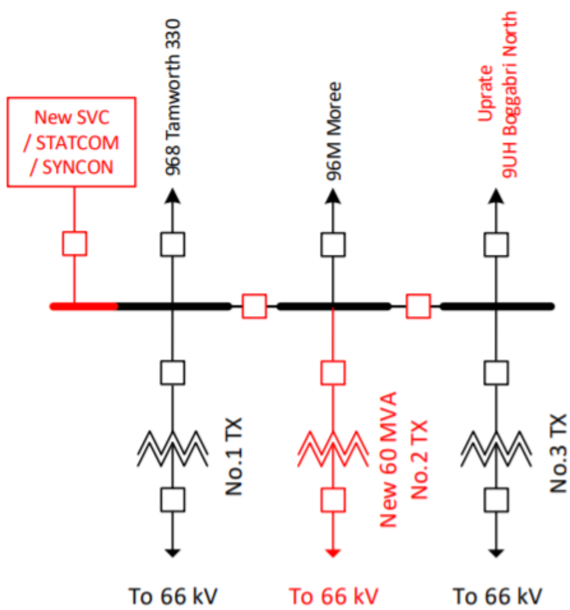
Figure E-13: Indicative Tamworth 330/132 kV substation layout under Option 2D



Option 3 – Rebuilding the existing line 969 from Tamworth to Gunnedah to be a double circuit line

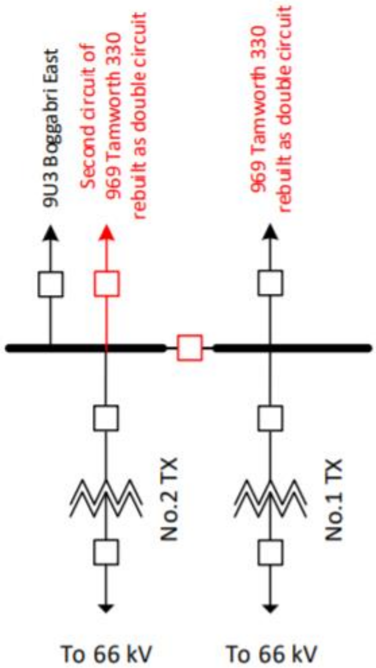
The indicative layout for the Narrabri 132/66 kV substation under Option 3A is shown in Figure E-14 below.

Figure E-14: Indicative Narrabri 132/66 kV substation layout under Option 3A



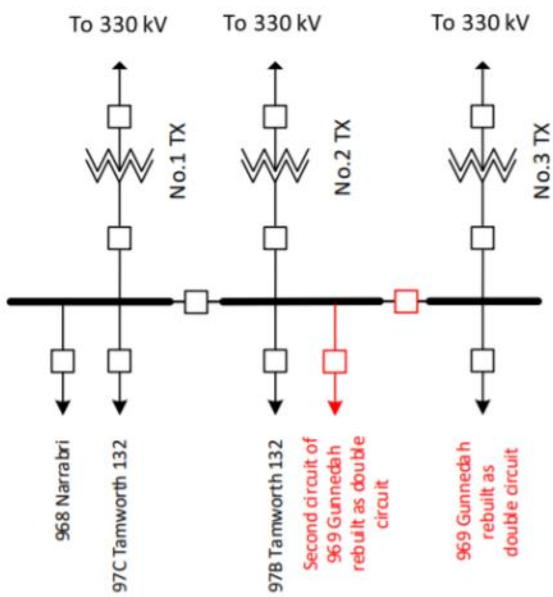
The indicative layout for the Gunnedah 132/66 kV substation under Options 3A and 3B is shown in Figure E-15 below.

Figure E-15: Indicative Gunnedah 132/66 kV substation layout under Options 3A and 3B



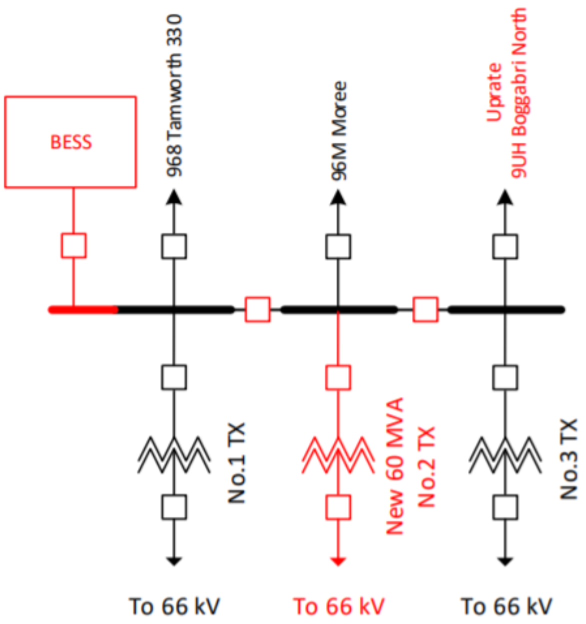
The indicative layout for the Tamworth 330/132 kV substation under Options 3A, 3B and 3C is shown in Figure E-16 below.

Figure E-16: Indicative Tamworth 330/132 kV substation layout under Options 3A, 3B and 3C



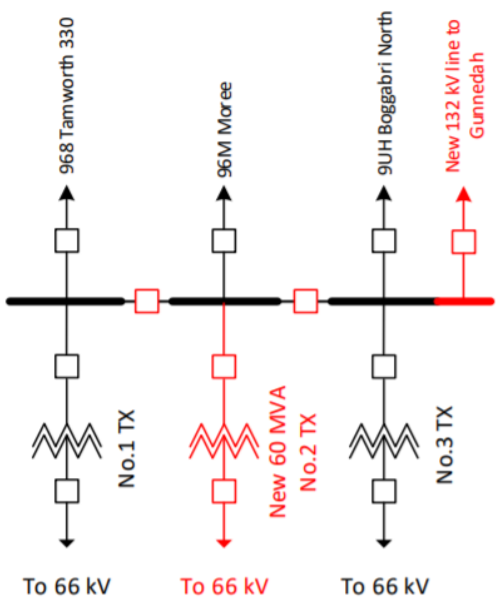
The indicative layout for the Narrabri 132/66 kV substation under Option 3B is shown in Figure E-17 below.

Figure E-17: Indicative Narrabri 132/66 kV substation layout under Option 3B



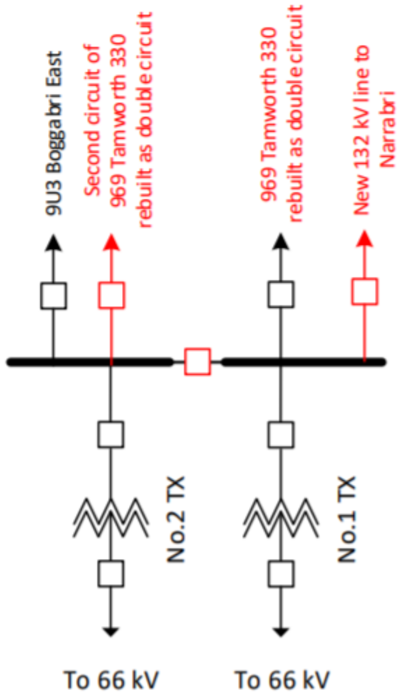
The indicative layout for the Narrabri 132/66 kV substation under Option 3C is shown in Figure E-18 below.

Figure E-18: Indicative Narrabri 132/66 kV substation layout under Option 3C



The indicative layout for the Gunnedah 132/66 kV substation under Option 3C is shown in Figure E-19 below.

Figure E-19: Indicative Gunnedah 132/66 kV substation layout under Option 3C



Appendix F Overview of the wholesale market modelling undertaken

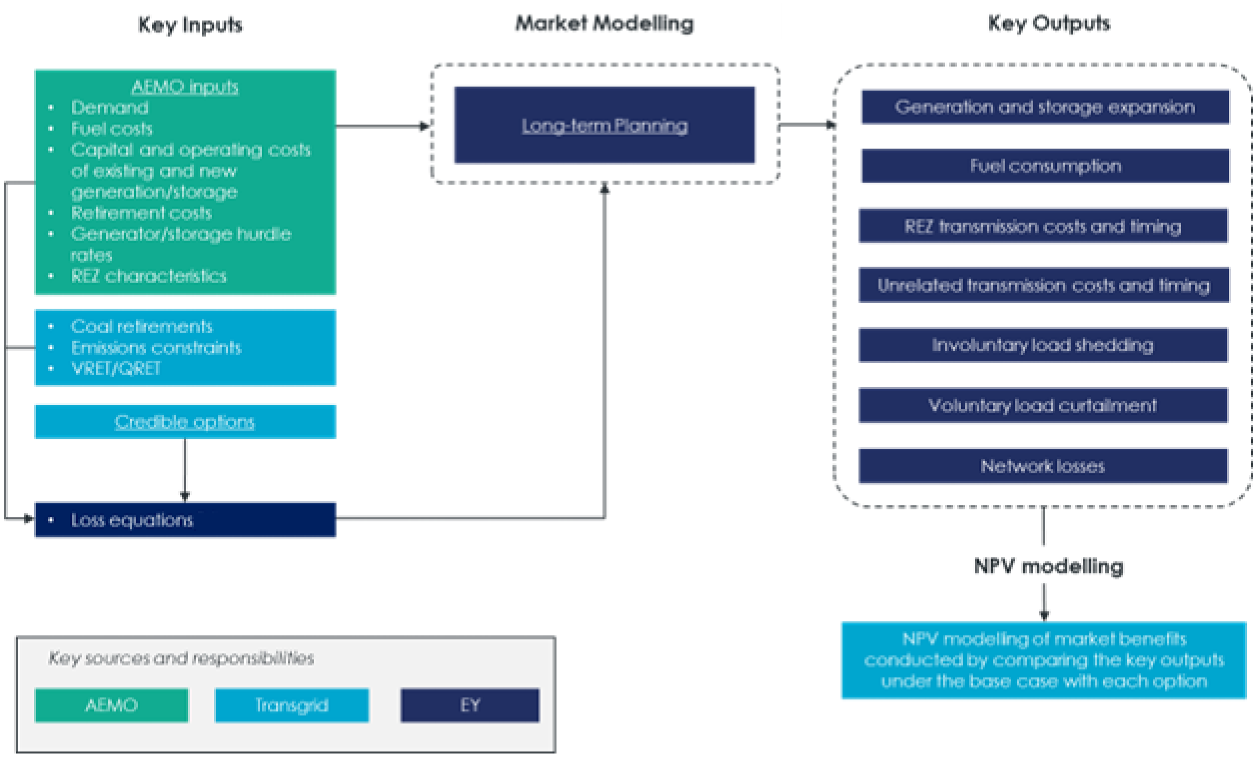
As outlined in the body of this PACR, we have engaged EY to undertake the wholesale market modelling as part of this PACR (which has not been amended since the initial PACR).

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 F-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 F-1: Overview of the market modelling process and methodologies



** As outlined in section 6.2, the avoided involuntary load shedding in the North West Slopes region of NSW has been estimated separately by Transgrid.*

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

Long-term Investment Planning

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

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

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

- it economically meets hourly regional and system-wide demand while accounting for network losses;
- it builds sufficient generation capacity to meet demand when economic while considering potential generator unplanned and planned outages;
- the cost of unserved energy is balanced with the cost of new generation investment to supply any potential shortfall;
- generator's technical specifications such as minimum stable loading, and maximum capacity are observed;
- notional interconnector flows do not breach technical limits and interconnector losses are accounted for;
- hydro storage levels and 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).[85]

Coal-fired and gas-fired generation is treated as dispatchable between its minimum load and its maximum load in the modelling. Coal-fired 'must run' generation is dispatched whenever available at least at its minimum load. Open cycle gas turbines are typically bid at their short run marginal cost with a zero minimum load level, and started and operated whenever the price is above that level.

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85 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 F-1: PACR modelled scenario key drivers input parameters

Key drivers input parameters	Step Change	Progressive Change	Hydrogen Superpower
Underlying consumption	ESOO 2021 (draft ISP 2022) – step change	ESOO 2021 (draft ISP 2022) – Progressive Change	ESOO 2021 (draft ISP 2022) – Hydrogen Superpower
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PSH, and large-scale batteries	2021 Inputs and Assumptions Workbook – step change	2021 Inputs and Assumptions Workbook – Progressive Change	2021 Inputs and Assumptions Workbook – Hydrogen Superpower
Retirements of coal-fired power stations	2021 Inputs and Assumptions Workbook – step change In line with expected closure year, or earlier if economic or driven by decarbonisation objectives	2021 Inputs and Assumptions Workbook – Progressive Change In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030	2021 Inputs and Assumptions Workbook – Hydrogen Superpower In line with expected closure year, or earlier if economic or driven by decarbonisation objectives
Gas fuel cost	2021 Inputs and Assumptions Workbook – step change Lewis Grey Advisory 2020, step change	2021 Inputs and Assumptions Workbook – Progressive Change Lewis Grey Advisory 2020, central	2021 Inputs and Assumptions Workbook – Hydrogen Superpower Lewis Grey Advisory 2020, step change
Coal fuel cost	2021 Inputs and Assumptions Workbook – step change Wood Mackenzie, step change	2021 Inputs and Assumptions Workbook – Progressive Change Wood Mackenzie, central	2021 Inputs and Assumptions Workbook – Hydrogen Superpower Wood Mackenzie, step change
NEM carbon budget to achieve 2050 emissions levels	2021 Inputs and Assumptions Workbook – step change 891 Mt CO_2-e 2023-24 to 2050-51	2021 Inputs and Assumptions Workbook – Progressive Change 932 Mt CO_2-e 2030-31 to 2050-51	2021 Inputs and Assumptions Workbook – Hydrogen Superpower 453 Mt CO_2-e 2023-24 to 2050-51
Victoria Renewable Energy Target (VRET)	40 % renewable energy by 2025 and 50 % renewable energy by 2030 VRET 2 including 600 MW of renewable capacity by 2025		
Queensland Renewable Energy Target (QRET)	50 % by 2030		
Tasmanian Renewable Energy Target (TRET)	2021 Inputs and Assumptions Workbook: 200 % Renewable generation by 2040		
NSW Electricity Infrastructure Roadmap	2021 Inputs and Assumptions Workbook: 12 GW NSW Roadmap, with 3 GW in the Central West Orana (CWO) REZ, modelled as generation constraint per the draft 2022 ISP 2 GW of long duration storage (8 hrs or more) by 2029-30		
EnergyConnect	Draft 2022 ISP – EnergyConnect commissioned by July 2025		
Western Victoria Transmission Network Project	Draft 2022 ISP – Western Victoria upgrade commissioned by November 2025		
HumeLink	Draft 2022 ISP – step change: HumeLink commissioned by July 2028	Draft 2022 ISP – Progressive Change: HumeLink commissioned by July 2035	Draft 2022 ISP – Hydrogen Superpower: HumeLink commissioned by July 2027
Marinus Link	Draft 2022 ISP –1st cable commissioned by July 2029 and 2nd cable by July 2031		
Victoria to NSW Interconnector Upgrade (VNI Minor)	Draft 2022 ISP – VNI Minor commissioned by December 2022		
NSW to QLD Interconnector Upgrade (QNI Minor)	Draft 2022 ISP – QNI minor commissioned by July 2022		

Key drivers input parameters	Step Change	Progressive Change	Hydrogen Superpower
QNI Connect	Draft 2022 ISP – step change: QNI Connect commissioned by July 2032	Draft 2022 ISP – Progressive Change: QNI Connect commissioned by July 2036	Draft 2022 ISP – Hydrogen Superpower: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030
VNI West	Draft 2022 ISP – step change: VNI West commissioned by July 2031	Draft 2022 ISP – Progressive Change: VNI West commissioned by July 2038	Draft 2022 ISP – Hydrogen Superpower: VNI West commissioned by July 2030
Victorian SIPS	Draft 2022 ISP – 300 MW/450 MWh, 250 MW for SIPS service and the remaining 50 MW can be deployed in the market by the operator on a commercial basis, November 2021.		
New-England REZ Transmission	Draft 2022 ISP – step change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	Draft 2022 ISP – Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	Draft 2022 ISP – Hydrogen Superpower: New England REZ Transmission Link commissioned by July 2027, and New England REZ Extension commissioned by July 2031
Snowy 2.0	2021 Inputs and Assumptions Workbook – Snowy 2.0 is commissioned by December 2026		

Appendix G Summary of consultation on the PADR

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

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

Table G. 1: Summary of consultation on the PADR

Summary of comment(s)	Submitter(s)	Our response
Demand forecasts		
Ensuring that mining/industrial loads are accounted for in demand forecasts		
Confirmation of intent to proceed with the Narrabri Coal Stage 3 expansion project, which received approval from the Independent Planning Commission on 1 April 2022[86] and is on schedule to require additional load from Q4 2024/Q1 2025 with a peak in Q4 2029/Q1 2030 (further details provided).	Whitehaven Coal, p. 1 (Narrabri Coal submission)	Section 2.3.1 outlines how the Narrabri Coal Stage 3 expansion project has now been reflected in the central demand forecast for this PACR.
Confirmation of intent to proceed with the Vickery expansion project, which has received state and federal approval and will require power by Q4 2024, with a maximum demand of 12.5 MVA.	Whitehaven Coal, p. 1 (Vickery expansion project submission)	
Ensuring that regional growth and proposed developments are appropriately accounted for in demand forecasts		
PIAC is concerned that demand forecasts based on regional growth plans may not be met, and recommends any projected demand relating to regional growth plans should be based on an independent assessment that takes into account the actual approved and/or financially committed developments.	PIAC, p. 1	See section 3.1. The Narrabri SAP has not been included in the assessment given the information provided by stakeholders regarding its commitment status.
PIAC is concerned about demand forecasts being treated as commercial-in-confidence, and considers that these forecasts should be released if costs are expected to be recovered from consumers.	PIAC, p. 1	See section 3.1.
Estimating the market benefits of the options		
Development of reasonable scenarios		
PIAC expressed a view that the high benefits scenario should not be included in the analysis due to unrealistic assumptions (25 per cent lower network capital costs, a high VCR estimate, and a low discount rate of 2.23 per cent).	PIAC, p. 1	See section 3.1.
PIAC recommends a more realistic approach of applying 50 per cent weighting to each of the central and low net economic benefits scenarios.	PIAC, p. 2	See section 3.2.

86 https://www.ipcn.nsw.gov.au/projects/2021/12/narrabri-underground-mine-stage-3-extension-project-ssd-10269

Transgrid
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NSW Electricity Networks Operations Holdings Pty Limited (ACN 609 169 959),
as trustee for NSW Electricity Networks Operations Trust (ABN 70 250 995 390).
Registered business name is TransGrid (ABN 70 250 995 390).