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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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.

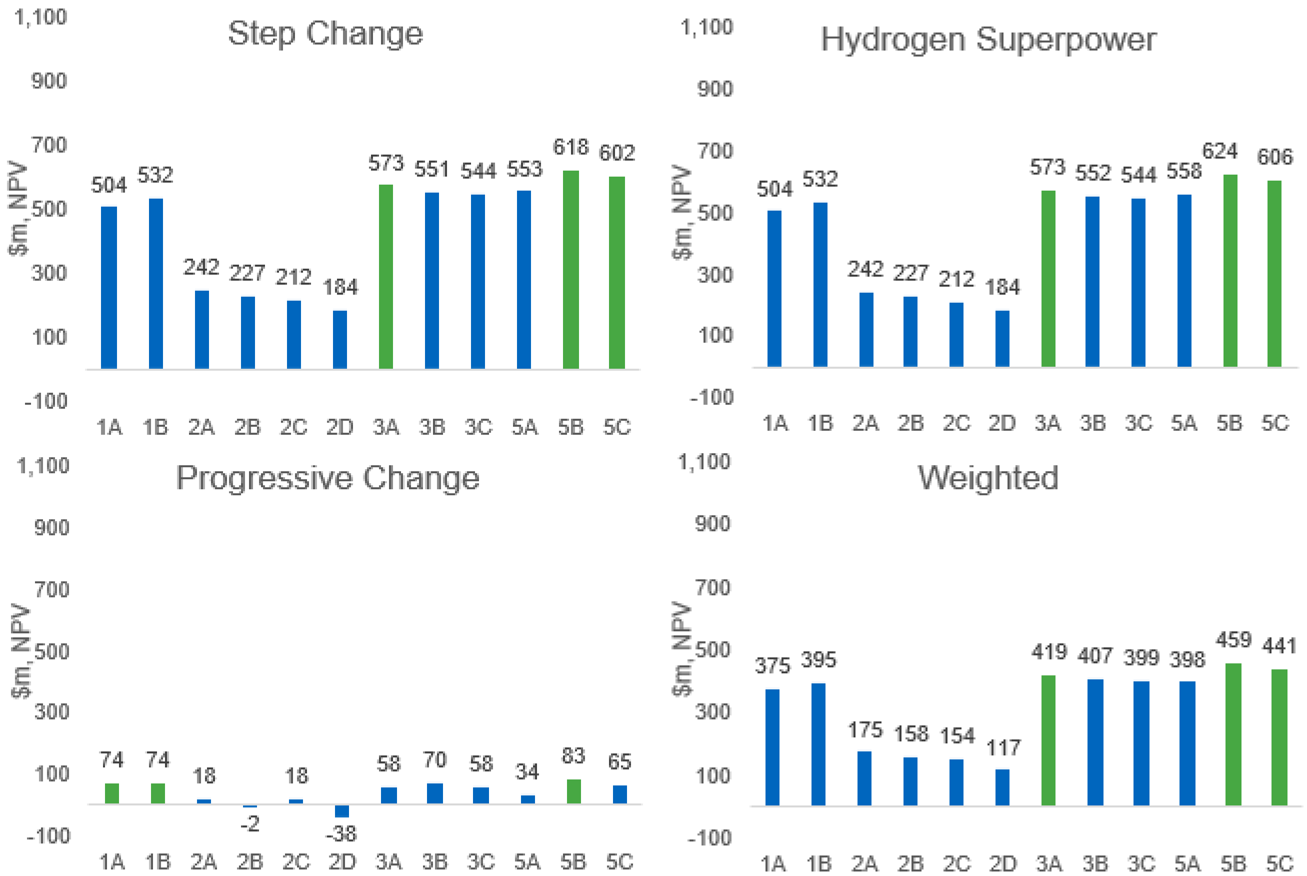
We have also investigated the sensitivity of the results to alternate weightings as part of this PACR (and they are found not to be sensitive).

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.

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.