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Maintaining Reliable Supply to the Bathurst, Orange and Parkes areas

RIT-T – Project Assessment Draft Report

Region: Central West New South Wales

Date of issue: 18 February 2022

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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining reliable supply to the Orange and Parkes areas of central west New South Wales (NSW). Publication of this Project Assessment Draft Report (PADR) represents the second step in the RIT-T process and follows the Project Specification Consultation Report (PSCR) and accompanying non-network expression of interest (EOI) released in March 2021.

The 'identified need' driving investment

As set out in our most recent Transmission Annual Planning Report (TAPR),[1] and our revenue proposal for the 2023-2028 period,[2] the latest forecasts indicate that electricity demand is expected to increase substantially in the Orange and Parkes areas going forward. This is mainly due to expected demand growth associated with the expansion of some existing large mine loads in the area, the planned connection of new mine/industrial loads and general load growth around Parkes, including from the NSW government's Parkes Special Activation Precinct (SAP).[3]

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.[4] 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.[5]

We have undertaken planning studies that show that the current central west 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.

While demand forecasts have reduced since the PSCR, due both to a fall in Essential Energy's general load forecasts as well as a decrease in several specific spot load forecasts, our updated planning studies still show that the current network will not be capable of supplying the expected combined increases in load in the area without breaching the NER requirements going forward. If the longer-term voltage constraints associated with the load growth in Orange and Parkes areas are unresolved, it could result in the interruption of a significant amount of electricity supply to customers under both normal and contingency conditions.

This RIT-T therefore assesses options to ensure the above NER requirements continue to be met in central west NSW 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.

1 Transgrid, *2021 Transmission Annual Planning Report*, p. 47, available at: https://www.transgrid.com.au/media/j2llfv1u/transmission-annual-planning-report-2021.pdf
2 Transgrid, *Revenue Proposal 2023–2028*, 31 January 2022, pp. 44-45.
3 https://www.nsw.gov.au/snowy-hydro-legacy-fund/special-activation-precincts/parkes-special-activation-precinct
4 These levels are specified in Clause S5.1a.4.
5 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 PADR analysis has benefited from stakeholder consultation

The PSCR and accompanying non-network EOI were released in March 2021. We subsequently received submissions from three parties to the PSCR and five parties to the EOI.

One of the submissions received directly in response the PSCR was from a non-network proponent. All three parties have requested confidentiality and so we have not reproduced any of their submission material in the PADR, nor have we published the submissions on our website. Similarly, the non-network proponents who responded to the EOI also requested confidentiality and so we have not reproduced any of their submission material in the PADR or on our website.

In light of the revision to the demand forecasts since the PSCR, during October 2021 we re-engaged with all parties who submitted a non-network solution to confirm their continuing interest and ensure appropriately sized, and costed, solutions were assessed in the PADR. This involved relaying the reduced requirements for non-network solutions under the revised demand forecasts and holding a number of meetings with proponents. Four out of the five parties that submitted to the EOI updated their proposals, while one withdrew their offer.

The credible options have been refined since the PSCR

The credible options considered in the PADR assessment have been refined since the PSCR, to reflect:

- submissions to the PSCR and EOI, resulting in four new options being included that utilise non-network technologies (including Battery Energy Storage Systems (BESS)) put forward by third-party proponents; and
- revised demand forecasts since the PSCR, which has led to the network elements being resized and rescoped.[6]

Key changes to the network elements since the PSCR, including from the lower demand forecasts, are:

- the size of components assisting with the short-term reactive support at Parkes and Panorama has fallen, which has in turn reduced their cost;
- a new 132 kV line from Wellington to Parkes has been included in some options to provide support around Parkes on account of the revised cost estimates finding it to be lower cost than the originally intended line (i.e., a new 132 kV line from Orange to Parkes) – these lines are also now required later in the assessment period;
- the option in the PSCR involving a new 330 kV line between Orange and Parkes has not been progressed in this PADR as the additional cost of this option is not expected to be offset by material additional benefits and so it is no longer considered commercially feasible (even under the high demand forecast); and
- many of the longer-term components of the options are no longer required (and so have been removed, reducing the cost of the options compared to the PSCR).

The options involving non-network solutions in the short-term have each been coupled with the eventual build of a new 132 kV line between Wellington and Parkes (which is the longer-term component of what is considered the preferred solely network option at this stage of the RIT-T (i.e., Option 3).

6 The lower demand forecasts also resulted in the originally proposed non-network solutions being reviewed and refined, as outlined in section 3 of this PADR.

The credible network options assessed in this PADR differ in the near-term by where, how and when new capacity is added to the central west network going forward. Specifically, the network options differ by:

- how reactive support is provided in the short-term (including through traditional transmission network elements as well as through installing dynamic reactive power devices);
- how much reactive support is provided in the short-term; and
- whether a new transmission line is ultimately built over the longer-term.

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

Table E-1: Summary of the credible options

Option	Description	Estimated capex ($2020/21)
New 330/132 kV substation at Orange ahead of a new Wellington to Parkes 132 kV line (if required)		
1A/1B[7]	• Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Wellington to Parkes 132 kV line	• $123 million[8]
Reactive support at Parkes and a new 330/132 kV substation at Orange ahead of additional reactive support at Parkes (if required)		
1C	• Initial synchronous condenser at Parkes 132 kV (40 MVA)	• $30 million
	• Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Second synchronous condenser at Parkes 132 kV (30 MVA)	• $26 million
	• Two further synchronous condensers at Parkes 132 kV (2 x 30 MVA)	• $51 million
Reactive support at Panorama and Parkes ahead of a new 132 kV line from Wellington to Parkes (if required)		
3	• Panorama 132 kV SVC (25 MVA) + synchronous condenser at Parkes 132 kV (3*30 MVA)	• $107 million
	• Wellington to Parkes 132 kV line	• $121 million
Reactive support at Panorama and Parkes ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)		
4	• Panorama 132 kV SVC (25 MVA) + synchronous condenser at Parkes 132 kV (3*30 MVA)	• $107 million
	• New Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Synchronous condenser at Parkes 132 kV (40 MVA)	• $28 million
BESS at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 132 kV line from Wellington to Parkes (if required)		

7 In the PSCR this option distinguished between Option 1A and 1B because of the then anticipated future stages of developments. These later stages are no longer considered necessary and so these two options have been collapsed into one option. The option naming has been retained for consistency.

8 Please note that the estimated cost of the Wellington to Parkes line is slightly higher for Option 1A/1B than it is for Option 3, Option 5, Option 7A, Option 7B, Option 7C and Option 7D since, for Option 1A/B, the new Wellington-Parkes line connection is the first work undertaken at Parkes and so it includes the scope to add 132 kV bus section circuit breakers (which is included in the earlier stages of Option 3, Option 5, Option 7A, Option 7B, Option 7C and Option 7D).

Option	Description	Estimated capex ($2020/21)
5	• 2 x 30 MVAr synchronous condensers at Parkes + 15 MW (30 MWh) BESS at Parkes + 20 MW (40 MWh) BESS at Panorama	• $156 million
	• Wellington to Parkes 132 kV line	• $121 million
BESS at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)		
6	• 2 x 30 MVAr synchronous condensers at Parkes + 15 MW (30 MWh) BESS at Parkes + 20 MW (40 MWh) BESS at Panorama	• $156 million
	• Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Synchronous condenser at Parkes 132 kV (40 MVA)	• $28 million
Combination of non-network solutions with the top-ranked network option (Option 3)		
7A	• Solar PV and BESS at Parkes • BESS at Panorama • Wellington to Parkes 132 kV line	• Confidential for the non-network components • $121 million for the line
7B	• Solar PV and BESS at Parkes • BESS at Panorama • Wellington to Parkes 132 kV line	• Confidential for the non-network components • $121 million for the line
7C	• BESS at Parkes • BESS at Panorama • Wellington to Parkes 132 kV line	• Confidential for the non-network components • $121 million for the line
7D	• BESS at Parkes • BESS at Panorama • 2 x 42.5 MVA synchronous condensers at Parkes • Wellington to Parkes 132 kV line	• Confidential for the non-network components (including the synchronous condensers) • $121 million for the line

Benefits from the options considered in this PADR

The key source of benefit expected for all credible options assessed in this PADR is avoided unserved energy to end consumers relative to the RIT-T 'base case', i.e., where action is not taken. Specifically, the current central west network is not capable of supplying the combined increases in load in the area 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. While the expected avoided unserved energy is substantial and will increase over time, we have capped it in the analysis so as to remove avoided unserved energy that is common to all options (since, including it, does not assist with identifying the preferred option overall), which is in line with the approach adopted in other RIT-Ts.[9]

Six of the credible options assessed in this PADR involve the use of BESS, including four from third party proponents of these solutions provided in response to the PSCR and EOI. The BESS are expected to be able to assist with providing reactive support in the short-term and to also use a portion of their capacity to dispatch to the wholesale market, replacing more costly generation that would otherwise be called on to operate, and thus provide wider wholesale market benefits in addition to the avoided unserved energy provided by all options. The additional wholesale market benefits associated with the BESS option component have been estimated using market modelling as part of this PADR.

Uncertainty has been captured by way of three scenarios

Uncertainty is captured under the RIT-T framework through the use of scenarios. The credible options have been assessed under three scenarios as part of this PADR assessment, which differ in terms of the key drivers of the estimated net market benefits.

The three scenarios are characterised as follows:

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

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

9 Section 6.1 outlines in more detail how the unserved energy that does not contribute to identifying the preferred option has been removed from the analysis.

Table E-2: Summary of the three scenarios modelled

Variable	Central	Low net economic benefits	High net economic benefits
Network capital costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Demand	Central demand forecast	Low demand forecast	High demand forecast
New renewable generation in the area	In-service, commissioning and committed generators.	In-service, commissioning, committed and advanced generators.	In-service, commissioning and committed generators.
Wholesale market benefits estimated	Estimated based on the 'progressive' 2022 ISP scenario	30 per cent lower than central scenario estimate	30 per cent higher than central scenario estimate
VCR	$53.48/kWh	$37.44/kWh	$69.53/kWh
Discount rate	5.50%	7.50%	2.23%

We consider that the central scenario is most likely since it is based primarily on a set of expected assumptions. We have therefore assigned this scenario a weighting of 50 per cent, with the other two scenarios being weighted equally with 25 per cent each.

The options involving non-network solutions in the short-term are strongly preferred over the solely network options

The results of the PADR assessment find that the options involving non-network solutions in the short-term coupled with the preferred network option in the long term (i.e., Option 7A, Option 7B, Option 7C and Option 7D) are strongly preferred over the solely network options. The options involving non-network solutions in the short-term are found to deliver estimated net benefits of approximately $3.8 billion to $3.9 billion overall relative to the base case 'do nothing' option on a weighted basis, which compares to $1.5 billion for the top-ranked solely network option (Option 3).

While Option 7D is the top-ranked option overall on a weighted basis, the options involving non-network solutions are found to have net benefits all within 2.5 per cent of each other and so are not considered materially different.

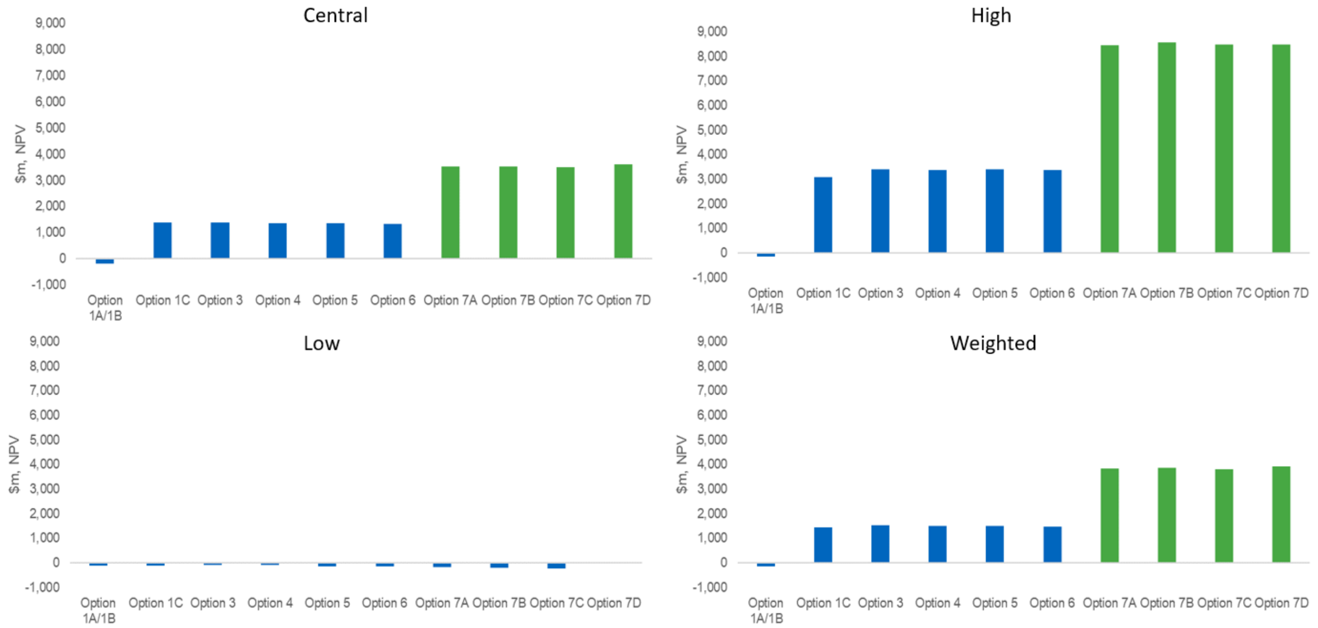
Options 7A-7D are all combined with the network component of Option 3 over the longer-term, to provide a complete solution. While Option 3 is found to have net benefits that are approximately 1 per cent greater than the next best network option (Option 4) on a weighted basis, it is found to have the lowest expected capital cost of all the solely network options (5 per cent lower than Option 1C and 12 per cent lower than Option 4 (the two next lowest cost network options)), which is why it is considered the preferred solely network option at this stage of the RIT-T and is the network option the non-network options have been coupled with.

Figure E.1 shows that while the level of net benefits differs across the central and high scenarios, the options involving non-network solutions in the short-term (i.e., Option 7A, Option 7B, Option 7C and Option

7D) are always strongly preferred over the solely network options. This is due to these options being assumed to be able to be commissioned approximately two to four years before the network options, which allows them to avoid substantial additional unserved energy in those early years.

While all options have marginally negative net benefits under the low economic benefits scenario, we note that Option 7D is the top-ranked option and that the preferred option is permitted to have negative net benefits under the RIT-T for a reliability corrective action.[10]

Figure E-1: Summary of the estimated net benefits



All charts in the figure above have been presented using the same scale in order to illustrate the headline differences between the scenarios.

Almost all of the estimated gross benefits are derived from avoided unserved energy, which make up between 93 and 99 per cent of the total gross benefits on a weighted basis for the four non-network options. While the estimated wider wholesale market benefits are not found to be material to the conclusion that the options involving non-network solutions are preferred over the solely network options, they are found to be material to which of the non-network options is top-ranked overall. We will therefore be working with proponents to refine the assessment of these wider benefits as part of the PACR.

At this stage of the RIT-T, the preferred options are therefore the options involving non-network solutions in the short-term, coupled with the eventual build of a new 132 kV line between Wellington and Parkes.

[10] Moreover, as noted above, the avoided unserved energy benefits are capped in the PADR analysis to remove unserved energy that does not contribute to identifying the preferred option and, if the full avoided unserved energy benefit was modelled, Option 7D would have positive net benefits under this scenario (but that all other options, including Option 3 and the other non-network options, would still have negative net benefits).

Assumed option timing is a key driver of the preferred option (and will be refined ahead of the PACR)

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.

Sensitivity analysis undertaken as part of this PADR shows that the conclusion that options involving non-network solutions in the short-term are strongly preferred over the solely network options is relatively robust to alternate assumed option timings. Specifically, it shows that:

- there would need to be a two year delay to the commissioning of the BESS under Option 7D combined with a two year bringing forward of Option 3 in order for Option 3 to be preferred (and, even under these assumptions, Option 3's net benefits would only be approximately 10 per cent greater than Option 7D's); and
- Option 3 would need to be brought forward two years (and Option 7D assumed to either have no change to its timing, or be delayed by one year), or Option 3 would need to be brought forward by one year and Option 7D is delayed by two years, to result in Option 3 being within 5 per cent of Option 7D.

We will therefore be focussing, internally and with third party proponents of non-network solutions, to firm up the assumed commissioning dates (and costs) for all options between now and the PACR, and to ensure that the assumed option timing is realistic in all cases. We expect that factors such as the assumed timing of land acquisition and planning approvals will be key to firm up and note that the current proposals from third parties display some diversity across these assumptions. It is expected that the assumed option timings in the PACR will reflect what option proponents are willing to commit to.

Next steps

We welcome written submissions on this PADR. Submissions are due on 7 April 2022.

Submissions should be emailed to our Regulation team via Regulatory.Consultation@transgrid.com.au.[11] In the subject field, please reference 'PADR Maintaining Reliable Supply to the Bathurst, Orange and Parkes areas project.'

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

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

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

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1. Introduction

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining reliable supply to the Orange and Parkes areas of central west New South Wales (NSW). Publication of this Project Assessment Draft Report (PADR) represents the second step in the RIT-T process and follows the Project Specification Consultation Report (PSCR) and accompanying non-network expression of interest (EOI) released in March 2021.

As set out in our most recent Transmission Annual Planning Report (TAPR),[12] and our revenue proposal for the 2023-2028 period,[13] the latest forecasts indicate that electricity demand is expected to increase substantially in the Orange and Parkes areas going forward. This is mainly due to expected demand growth associated with the expansion of some existing large mine loads in the area, the planned connection of new mine/industrial loads and general load growth around Parkes, including from the NSW government's Parkes Special Activation Precinct (SAP).[14]

Our power system studies forecast that the expected load growth in the Orange and Parkes areas will reach the voltage stability limits of the existing 132 kV supply network in the central west 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 central west 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.[17]

This RIT-T therefore examines various 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.

As stated in our revenue proposal for the 2023-2028 period,[18] we will include the preferred option for the near-term elements identified through the RIT-T in our augmentation expenditure forecast in our Revised Revenue Proposal for the forthcoming regulatory period. More information on our 2023-28 revenue proposal can be found here. We have also included a contingent project for stage 2 works for the longer-term elements, or if the high demand forecast eventuates.

[12] Transgrid, *2021 Transmission Annual Planning Report*, p. 47, available at: https://www.transgrid.com.au/media/j2llfv1u/transmission-annual-planning-report-2021.pdf

[13] Transgrid, *Revenue Proposal 2023–2028*, 31 January 2022, pp. 44-45.

[14] https://www.nsw.gov.au/snowy-hydro-legacy-fund/special-activation-precincts/parkes-special-activation-precinct

[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.

[17] While the PSCR also identified thermal constraints in the area if action is not taken, particularly during times of low renewable generation dispatch in the region, demand forecasts have since reduced and our updated planning studies no longer forecast thermal constraints over the planning horizon of this RIT-T.

[18] Transgrid, *Revenue Proposal 2023–2028*, 31 January 2022, p. 112.

1.1. Purpose

The purpose of this PADR is to:

- confirm the identified need for the investment, and describe the assumptions underlying this need, and any changes to these assumptions since the PSCR;
- summarise the consultation undertaken since the PSCR and highlight how it has been reflected in the RIT-T analysis;
- describe the options being assessed under this RIT-T, including how these have been shaped as part of the PSCR consultation and the additional options proposed in submissions. We have also described how the options have been modified in light of revised demand forecasts since the PSCR;
- identify and confirm the market benefits expected from the various credible options;
- present the results of the NPV analysis for each of the credible options assessed;
- describe the key drivers of these results, and the assessment that has been undertaken to ensure the robustness of the conclusion; and
- identify the preferred option at this stage of the RIT-T, i.e., the option that is expected to maximise net market benefits.

Overall, this report provides transparency into the planning considerations for investment options to stabilise the central west NSW power system, and the associated market benefits. A key purpose of this PADR, and the RIT-T more broadly, is to provide interested stakeholders the opportunity to review the analysis and assumptions, provide input to the process, and have certainty and confidence that the preferred option has been robustly identified as optimal.

The credible options outlined in this PADR 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. How to make a submission and next steps

We welcome written submissions on this PADR. Submissions are due on 7 April 2022.

Submissions should be emailed to our Regulation team via Regulatory.Consultation@transgrid.com.au.[19] In the subject field, please reference 'PADR Maintaining Reliable Supply to the Bathurst, Orange and Parkes areas project.'

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

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

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

2. Benefits from improving the stability of the central west NSW power system

This section outlines the key benefits expected from the various options assessed in this PADR for improving the stability of the central west NSW power system.

It first summarises and updates the 'identified need' for this RIT-T from the PSCR before outlining how the demand forecasts have been updated and how the non-network options put forward in submissions to the PSCR and EOI are expected to be able to provide additional sources of market benefit.

More information on the current network area is provided in Appendix B.

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.[20] 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.[21]

We have undertaken planning studies that show that the current central west 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.

Demand forecasts have reduced since the PSCR, due both to a fall in Essential Energy's general load forecasts as well as a decrease in specific spot load forecasts, as described more fully below. However, our updated planning studies still show that the current network will not be capable of supplying the combined expected increases in load in the area without breaching the NER requirements going forward.

The PSCR identified thermal constraints, in addition to voltage constraints, in the area if action is not taken, particularly during times of low renewable generation dispatch in the region. The revised (lower) demand forecasts have resulted in our updated planning studies no longer forecasting thermal constraints over the planning horizon of this RIT-T.

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

This RIT-T therefore assesses options to ensure the above NER requirements continue to be met in central west NSW 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.

In response to the PSCR and the accompanying non-network EOI, this PADR assesses a number of options involving non-network solutions that can not only meet the voltage requirements but also provide a

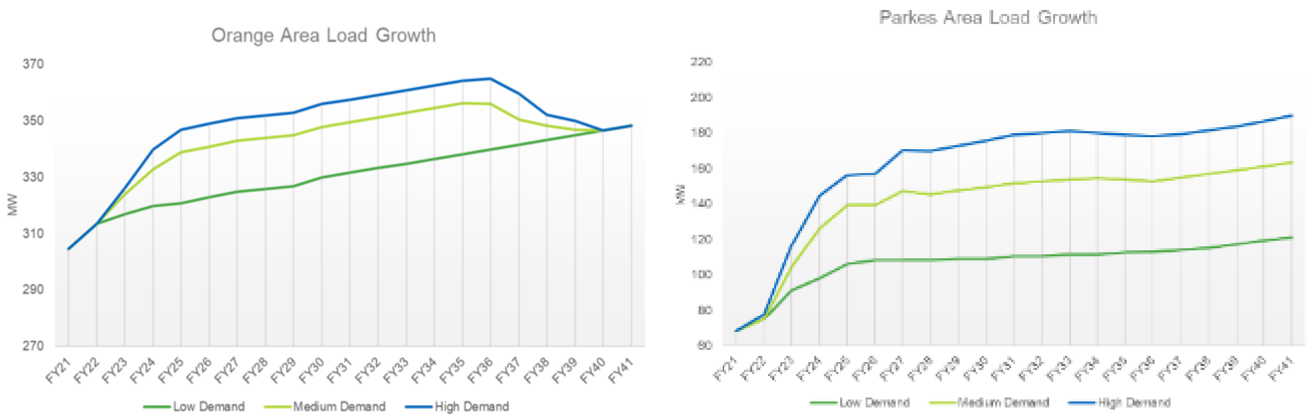
[20] These levels are specified in Clause S5.1a.4.
[21] These requirements are set out in Clauses 4.2.6, 4.2.4 and 4.2.2(b) of the NER. The requirement for secure operation of the power system in Clause 4.2.4 requires the power system to be in a satisfactory operating state following any credible contingency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

range of wider wholesale market benefits. The source of the expected benefits for these options is discussed in section 2.3 below.

2.2. Demand forecasts have been updated since the PSCR

Demand forecasts are a key driver of the identified need for this RIT-T and are expected to increase significantly in the central west NSW power system due to both underlying general load growth as well as specific spot load developments coming online. The PADR has considered three demand forecasts, representing different quantities, timings and locations for key forecast loads, as shown in Figure 2 below.

Figure 2: Peak demand forecasts for the Orange/Panorama area and the Parkes area



The demand forecasts feeding into the identified need for this RIT-T have been updated since the PSCR to reflect the latest Essential Energy demand forecasts available at the time of preparing this PADR and the most recent information provided by external parties on the current state of key projects. Specifically:

- Essential Energy has provided revised general demand forecasts for each of Orange, Panorama and Parkes as part of an annual update, all of which continue to show load growth, but at a lower rate than the forecasts available at the time of the PSCR (these revised forecasts have been reflected in our 2021 TAPR):
  - the forecast of summer peak at Panorama is now 69 MW/10 MVAr in 2022 (10 MW/3 MVAr below the PSCR forecast);
  - the forecast of summer peak at Orange 66 kV is now 53 MW/6 MVAr in 2022 (3 MW/ 3 MVAr below the PSCR forecast); and
  - the forecast of summer peak at Parkes 66 kV is now 31 MW/2 MVAr in 2022 (0 MW/8 MVAr below the PSCR forecast).
- Further discussions with the NSW government have resulted in a more gradual demand growth being assumed for the Parkes SAP.
- The timing of one of the anticipated mining loads has been brought forward and increased slightly, based on the most recent information (and is reflected in all three demand forecasts);
- Essential Energy has informed us of one new mine connection and load growth at another existing mine in its network (both have been included in the high demand forecast modelled in this PADR, with the names and details kept confidential).

The updated demand forecasts have been constructed to reflect the various stages of development for each key load, as well as to investigate sufficient diversity in terms of location of future spot loads to assess how the net benefit of the options considered in the PADR varies across these key assumptions.

2.2.1. Updated forecast voltage limits if action is not taken

The changes in the load forecasts have had a consequent impact on the forecast voltage limits if action is not taken under the base case.

Figure 3 and Figure 4 show the updated demand forecasts and the updated voltage limits for Orange and Parkes 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.

Figure 3: Updated peak demand forecast and voltage limit for the Orange/Panorama area

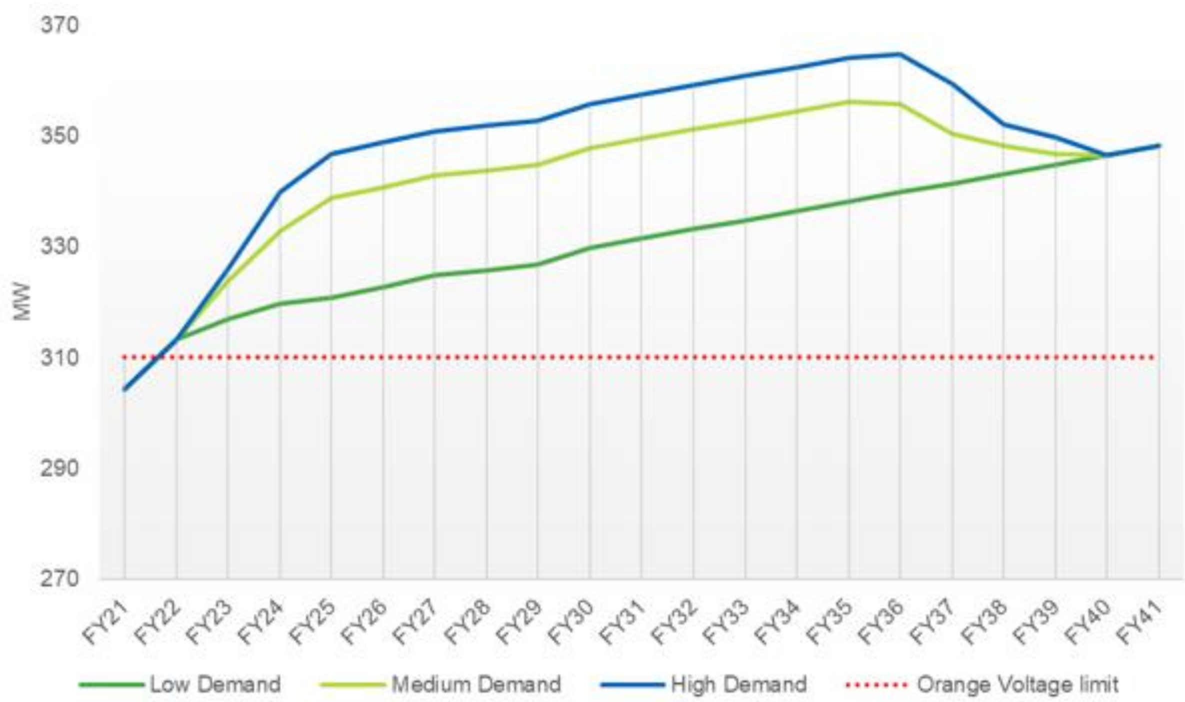
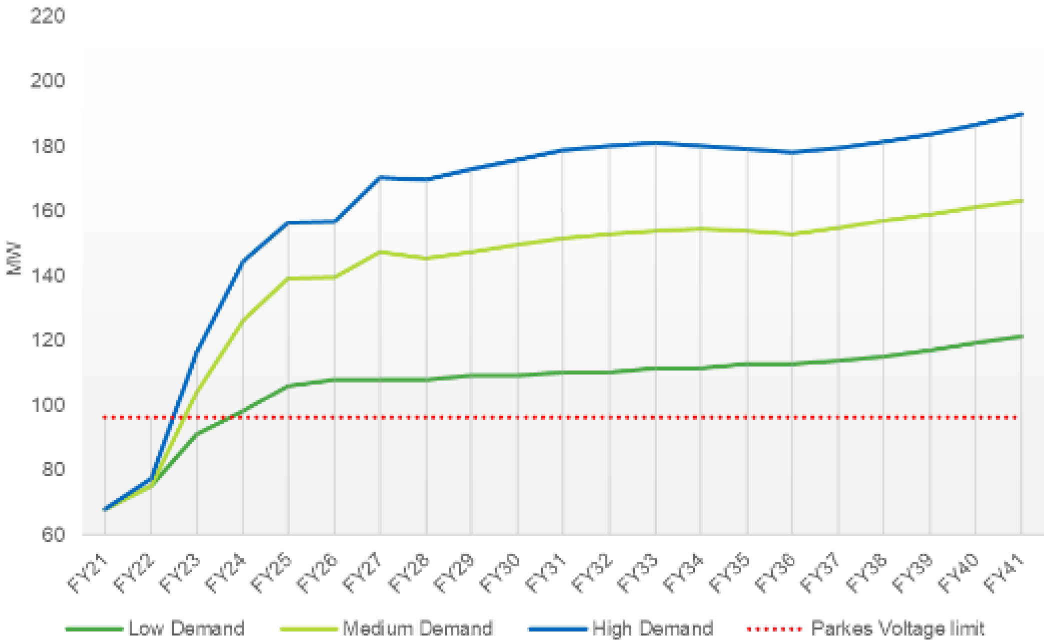


Figure 4: Peak demand forecast and voltage limit for the Parkes area



In calculating the limits, we have continued to assume that four capacitor banks will be installed in Orange North, Panorama and Parkes as part of separate Transgrid projects, required to address already committed load. The capacitor banks at Orange North and Panorama are expected to be in-service by October 2022, while the timing for Parkes is still being determined.

2.2.2. Updated reactive power margin shortfalls if action is not taken

Our system studies also indicate that under the revised demand forecasts, the voltage constraints will result in a reactive margin shortfall around the Orange and Parkes/Panorama areas after 2023 if action is not taken. As per the requirement under Clause S5.1.8 of the NER, a minimum reactive power margin of 1 per cent of the maximum fault level has to be maintained at each location. Accordingly, the minimum reactive power margins required at the Panorama 66 kV BSP and Parkes 132 kV BSP are 12.3 MVAr and 10.1 MVAr, respectively.

As shown in Table 2-1, a reactive power margin short-fall (in red) is projected at the Parkes 132 kV and Panorama 66 kV BSPs after 2025, under (N-1) contingency conditions (for the medium demand forecast).

Table 2-1: Projected reactive power margin at the Parkes 132 kV and Panorama 66 kV Bulk Supply Points (medium demand forecast)

Bulk Supply Point	Contingency	Required min Q Margin as per NER (MVAr)	Q Margin in 2023 (MVAr)	Q Margin in 2025 (MVAr)	Q Margin in 2030 (MVAr)
Panorama 66 kV	TL 94X	12.3	45.6	13.3	-7.0
Parkes 132 kV	TL 94K	10.1	22.0	-45.8	-69.8

While we project that there will be reactive margin shortfalls if nothing is done, these are considered a secondary concern to the forecast voltage constraints. Specifically, the voltage constraints are expected to be the first and most material constraint to be reached and, once resolved, will fully resolve the reactive power margin shortfall as well.

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

Six of the credible options assessed in this PADR involve the use of BESS, including four from third party proponents of these solutions provided in response to the PSCR and EOI. The BESS are expected to be able to assist with providing reactive support in the short-term and to also use a portion of their capacity to dispatch to the wholesale market, replacing more costly generation that would otherwise be called on to operate, and thus provide wider wholesale market benefits in addition to the avoided unserved energy provided by all options.

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 and avoided generator dispatch costs. However, they are also found to ultimately not be material to the outcome of this PADR in terms of which options are top ranked overall (as outlined in section 7).

While the other credible network options (i.e., the solely network options) will provide additional system strength around Parkes and/or relieve emerging line constraints around Bathurst and Orange, we do not consider there to be material wholesale market benefits associated with these options. Specifically, while providing additional system strength around Parkes and/or relieving line constraints may affect the investment decisions of future local renewable generators on the 132 kV network, upstream 330 kV network constraints outside of those considered in this RIT-T mean that any new generation is not expected to displace the output of generation elsewhere and so there are not expected to be any material wider wholesale market impacts between the options and the base case. As a consequence, the credible options considered in this RIT-T do not address network constraints between competing generators and so will not have an impact on generation dispatch outcomes and the wholesale electricity market.

3. Consultation on the PSCR

The PSCR and accompanying non-network EOI were released in March 2021. We subsequently received submissions from three parties to the PSCR and five parties to the EOI.

One of the submissions received directly in response the PSCR was from a non-network proponent. All three parties have requested confidentiality and so we have not reproduced any of their submission material in the PADR, nor have we published the submissions on our website. We have responded separately to these parties on the points raised in their submissions.

Similarly, the non-network proponents who responded to the EOI also requested confidentiality and so we have not reproduced any of their submission material in the PADR or on our website.

In light of the revision to the demand forecasts since the PSCR, during October 2021 we re-engaged with all parties who submitted a non-network solution to confirm their continuing interest and ensure appropriately sized, and costed, solutions were assessed in the PADR. This involved relaying the reduced requirements for non-network solutions under the revised demand forecasts and holding a number of meetings with proponents. Four out of the five parties that submitted to the EOI updated their proposals, while one withdrew.

4. Credible options assessed

The credible options considered in the PADR assessment have been refined since the PSCR, to reflect:

- submissions to the PSCR and EOI, resulting in four new options being included that utilise non-network technologies put forward by third-party proponents; and
- revised demand forecasts since the PSCR, which has led to the network elements being resized and rescoped.[22]

Key changes to the network elements since the PSCR, including from the lower demand forecasts, are:

- the size of components assisting with the short-term reactive support at Parkes and Panorama has fallen, which has in turn reduced their cost;
- a new 132 kV line from Wellington to Parkes has been included in some options to provide support around Parkes on account of the revised cost estimates finding it to be lower cost than the originally intended line (i.e., a new 132 kV line from Orange to Parkes) – these lines are also now required later in the assessment period;
- the option in the PSCR involving a new 330 kV line between Orange and Parkes has not been progressed in this PADR as the additional cost of this option is not expected to be offset by material additional benefits and so it is no longer considered commercially feasible (even under the high demand forecast); and
- many of the longer-term components of the options are no longer required (and so have been removed, reducing the cost of the options compared to the PSCR).

We have commented on where options have been refined since the PSCR in each of the sections below.

The credible network options assessed in this PADR differ in the near-term by where, how and when new capacity is added to the central west network going forward. Specifically, the network options differ by:

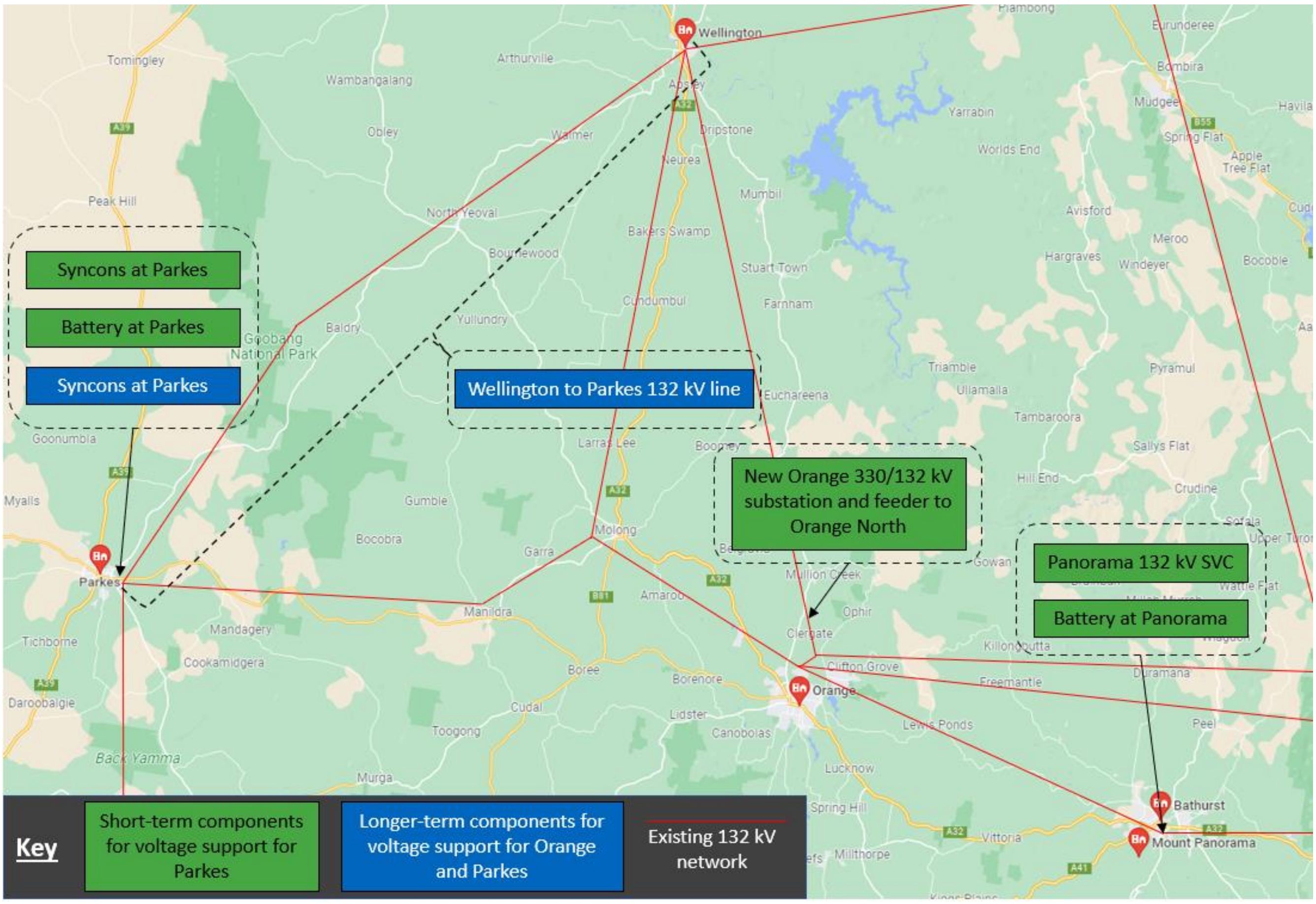
- how reactive support is provided in the short-term (including through traditional transmission network elements as well as through installing dynamic reactive power devices);
- how much reactive support is provided in the short-term; and
- whether a new transmission line is ultimately built over the longer-term.

Figure 5 below illustrates the various components that form the credible network options considered. 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.

[22] The lower demand forecasts also resulted in the originally proposed non-network solutions being reviewed and refined, as outlined in section 3.

Figure 5: Various components the credible network options involve



While the new Wellington to Parkes 132 kV line is shown in blue in this figure, as it is generally a 'longer-term' component for the options, we note that it is required in 2027/28 for Option 1A/1B under the central and high forecasts (but is not required under the low forecast).

As outlined in section 4.7, each of the four non-network solutions has been modelled in terms of its ability to efficiently defer or avoid the short-term reactive support requirements at Panorama and/or Parkes for the preferred network option at this stage of the RIT-T (i.e., Option 3).

Table 4-1 below summarises each of the credible options assessed in the PADR. All options are considered to meet the identified need from a technical, commercial, and project delivery perspective.[23] As outlined in section 8, the assumed timing of each option is expected to be a key determinant of the ultimately preferred option and will be further investigated as part of finalising the PACR.

While all potential stages of each option are shown in Table 4-1, the later stages 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) and the high demand forecast. The timing of the initial stage for all options has been fixed across the three demand forecasts (since these stages effectively need to be committed to now to ensure commissioning in time under the central forecast), while the timing of the later stages varies by demand forecast depending on when they are required (since they do not yet need to be

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

committed to). The individual option sections below detail the specific timing assumed for each stage of each option under the three demand forecasts.

Table 4-1: Summary of the credible options

Option	Description	Estimated capex ($2020/21)
New 330/132 kV substation at Orange ahead of a new Wellington to Parkes 132 kV line (if required)		
1A/1B[24]	• Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Wellington to Parkes 132 kV line	• $123 million[25]
Reactive support at Parkes and a new 330/132 kV substation at Orange ahead of additional reactive support at Parkes (if required)		
1C	• Initial synchronous condenser at Parkes 132 kV (40 MVA)	• $30 million
	• Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Second synchronous condenser at Parkes 132 kV (30 MVA)	• $26 million
	• Two further synchronous condensers at Parkes 132 kV (2 x 30 MVA)	• $51 million
Reactive support at Panorama and Parkes ahead of a new 132 kV line from Wellington to Parkes (if required)		
3	• Panorama 132 kV SVC (25 MVA) + synchronous condenser at Parkes 132 kV (3*30 MVA)	• $107 million
	• Wellington to Parkes 132 kV line	• $121 million
Reactive support at Panorama and Parkes ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)		
4	• Panorama 132 kV SVC (25 MVA) + synchronous condenser at Parkes 132 kV (3*30 MVA)	• $107 million
	• New Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Synchronous condenser at Parkes 132 kV (40 MVA)	• $28 million
BESS at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 132 kV line from Wellington to Parkes (if required)		
5	• 2 x 30 MVAr synchronous condensers at Parkes + 15 MW (30 MWh) BESS at Parkes + 20 MW (40 MWh) BESS at Panorama	• $156 million
	• Wellington to Parkes 132 kV line	• $121 million
BESS at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)		
6	• 2 x 30 MVAr synchronous condensers at Parkes + 15 MW (30 MWh) BESS at Parkes + 20 MW (40 MWh) BESS at Panorama	• $156 million

[24] In the PSCR this option distinguished between Option 1A and 1B because of the then anticipated future stages of developments. These later stages are no longer considered necessary and so these two options have been collapsed into one option. The option naming has been retained for consistency.

[25] Please note that the estimated cost of the Wellington to Parkes line is slightly higher for Option 1A/1B than it is for Option 3, Option 5, Option 7A, Option 7B, Option 7C and Option 7D since, for Option 1A/B, the new Wellington-Parkes line connection is the first work undertaken at Parkes and so it includes the scope to add 132 kV bus section circuit breakers (which is included in the earlier stages of Option 3, Option 5, Option 7A, Option 7B, Option 7C and Option 7D).

Option	Description	Estimated capex ($2020/21)
	• Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	• $164 million
	• Synchronous condenser at Parkes 132 kV (40 MVA)	• $28 million
Combination of non-network solutions with the top-ranked network option (Option 3)		
7A	• Solar PV and BESS at Parkes • BESS at Panorama • Wellington to Parkes 132 kV line	• Confidential for the non-network components • $121 million for the line
7B	• Solar PV and BESS at Parkes • BESS at Panorama • Wellington to Parkes 132 kV line	• Confidential for the non-network components • $121 million for the line
7C	• BESS at Parkes • BESS at Panorama • Wellington to Parkes 132 kV line	• Confidential for the non-network components • $121 million for the line
7D	• BESS at Parkes • BESS at Panorama • 2 x 42.5 MVA synchronous condensers at Parkes • Wellington to Parkes 132 kV line	• Confidential for the non-network components (including the synchronous condensers) • $121 million for the line

Capital costs for the network options have been revised since the PSCR 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. All network options are assumed to have annual operating and maintenance costs equal to approximately two per cent of their capital costs.

The costs of the non-network options have been incorporated in the PADR assessment in line with the guidance provided by the AER as part of its 2020 update of the RIT-T Application Guidelines.[26] In particular, since the non-network options do not involve currently committed or anticipated projects (as defined in the RIT-T) the PADR assessment reflects:

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

Should any components of these options become committed, or anticipated, under the RIT-T before the PACR is finalised, the treatment of their costs will be updated accordingly in the PACR analysis.

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

The market benefits associated with the operation of the non-network solutions outside of the times needed for network support have also been reflected in the assessment of market benefits (see section 6.3).

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 1A/1B – New 330/132 kV substation at Orange ahead of a new Wellington to Parkes 132 kV line (if required)

Option 1A/1B involves constructing:

- a new 330/132 kV substation at Orange initially (including two transformers and a 132kV line to the existing Orange North substation); and
- a new Wellington to Parkes 132 kV line, if required.

Table 4-2 summarises the optimal assumed timing for each component under the three different demand forecasts investigated.

Table 4-2: Summary of the assumed timing for each component of Option 1A/1B across the forecasts

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	2027/28	2027/28	2027/28
Wellington to Parkes 132 kV line	NA	2027/28	2027/28

The establishment of a new Orange 330/132 kV substation involves:[27]

- a cut-in to Line 72 (Wellington to Mt Piper 330 kV);
- a cut-in to Line 947 (Orange North to Wellington Tee Burrendong)
- two new 330/132 kV transformers (375 MVA);
- a new 132 kV Line to existing Orange North substation; and
- a new 132 kV bay (and a circuit breaker) at the existing Orange North 132 kV substation.

Figure 6 below illustrates the type and location of the key elements for Option 1A/1B.[28] While the new Wellington to Parkes 132 kV line is shown in blue in this figure, as it is generally a 'longer-term' component for other options, we note that it is required in 2027/28 for this option under the central and high forecasts (but is not required under the low forecast).

[27] This work is the same for all options that involve this component.

[28] While the new Wellington to Parkes 132 kV line is shown in blue in this figure, as it is generally a 'longer-term' component for other options, we note that it is required in 2027/28 for this option under the central and high forecasts.

Figure 6: Overview of the key elements in Option 1A/1B

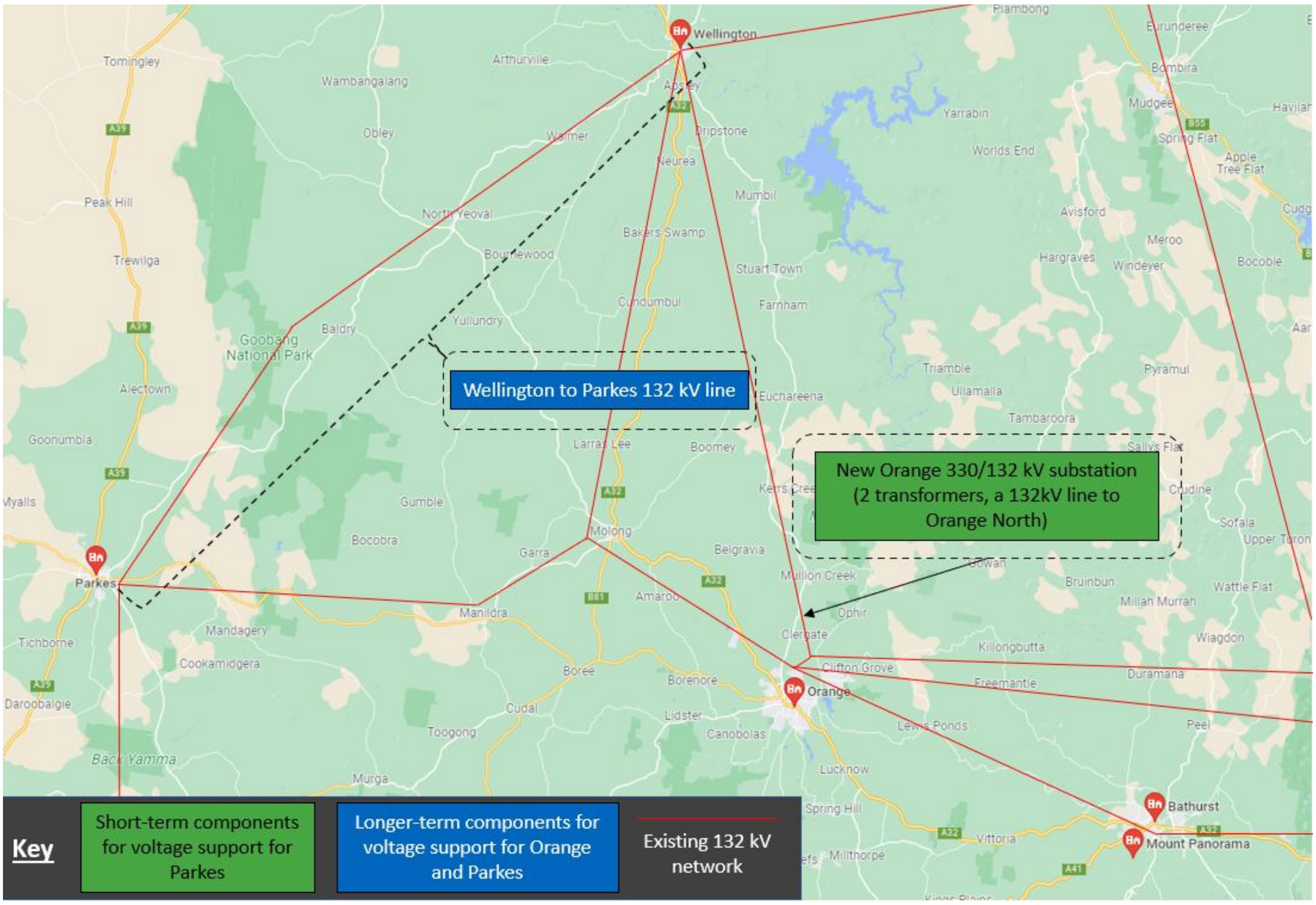


Table 4-3 summarises the expected construction time for each component.

Table 4-3: Summary of the expected construction time for each component of Option 1A/1B

Component	Expected construction time
Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	59 months
Wellington to Parkes 132 kV line	64 months

4.2. Option 1C – Reactive support at Parkes and a new 330/132 kV substation at Orange ahead of additional reactive support at Parkes (if required)

Option 1C involves constructing:

- an initial synchronous condenser at Parkes 132 kV (40 MVA);
- a new 330/132 kV substation at Orange (including two transformers and a 132kV line to the existing Orange North substation);
- a second synchronous condenser at Parkes 132 kV (30 MVA), if required; and
- two further synchronous condensers at Parkes 132 kV (2 x 30 MVA), if required.

The extent of the works for the new 330/132 kV substation at Orange are the same as set out under Option 1A/1B.

Table 4-4 summarises the optimal assumed timing for each component under the three different demand forecasts investigated.

Table 4-4: Summary of the assumed timing for each component of Option 1C across the forecasts

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
Initial synchronous condenser at Parkes 132 kV (40 MVA)	2026/27	2026/27	2026/27
Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	2031/32	2027/28	2027/28
Second synchronous condenser at Parkes 132 kV (30 MVA)	NA	2031/32	2027/28
Two further synchronous condensers at Parkes 132 kV (2 x 30 MVA)	NA	NA	2027/28

Figure 7 below illustrates the type and location of the key elements for Option 1C.

Figure 7: Overview of the key elements in Option 1C

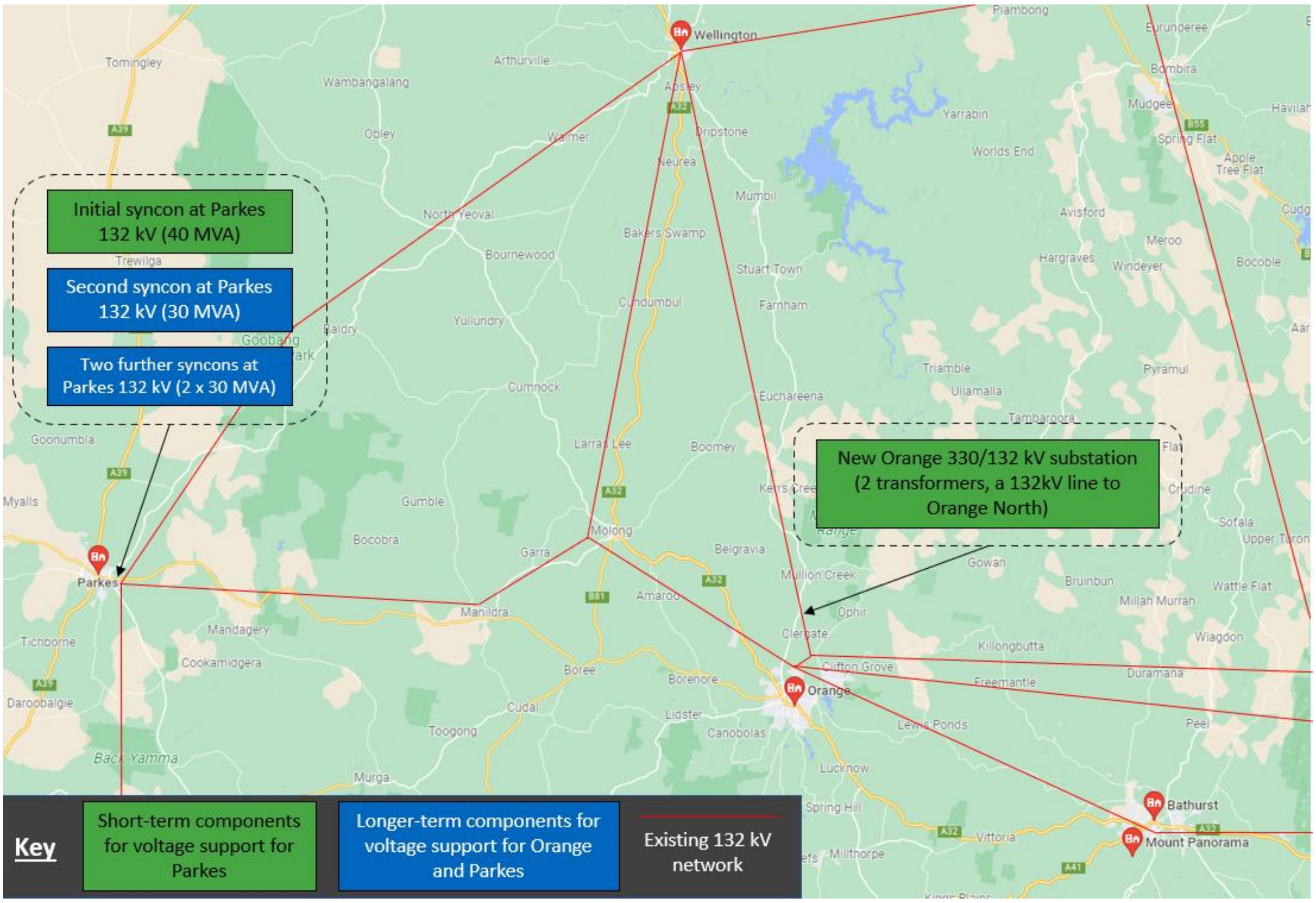


Table 4-5 summarises the expected construction time for each component.

Table 4-5: Summary of the expected construction time for each component of Option 1C

Component	Expected construction time
Initial synchronous condenser at Parkes 132 kV (40 MVA)	40 months
Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	59 months
Second synchronous condenser at Parkes 132 kV (30 MVA)	40 months
Two further synchronous condensers at Parkes 132 kV (2 x 30 MVA)	40 months

4.3. Option 3 – Reactive support at Panorama and Parkes ahead of a new 132 kV line from Wellington to Parkes (if required)

Option 3 involves constructing:

- Panorama 132 kV SVC (25 MVA)[29] and three synchronous condensers at Parkes 132 kV (3*30 MVA); and
- a new Wellington to Parkes 132 kV line, if required.

Table 4-6 summarises the optimal assumed timing for each component under the three different demand forecasts investigated.

Table 4-6: Summary of the assumed timing for each component of Option 3 across the forecasts

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
Panorama 132 kV SVC (25 MVA) + synchronous condenser at Parkes 132 kV (3*30 MVA)	2026/27	2026/27	2026/27
Wellington to Parkes 132 kV line	NA	2031/32	2027/28

A key benefit of Option 3 (and the other options involving dynamic reactive support upfront (i.e., Option 1C, Option 4, Option 5 and Option 6)) is that they are able to be commissioned a year earlier than Option 1A/1B and so avoid additional unserved energy. However, Option 1C involves constructing a synchronous condenser in 2026/27 that is expected to avoid most, but not all of the unserved energy in that year.

Figure 8 below illustrates the type and location of the key elements for Option 3.

[29] Since the PSCR, we have considered SVCs, synchronous condensers and STATCOMs for this component and now assume an SVC since it has been found to be the lowest cost of the three choices (with the other two not expected to provide any additional benefits).

Figure 8: Overview of the key elements in Option 3

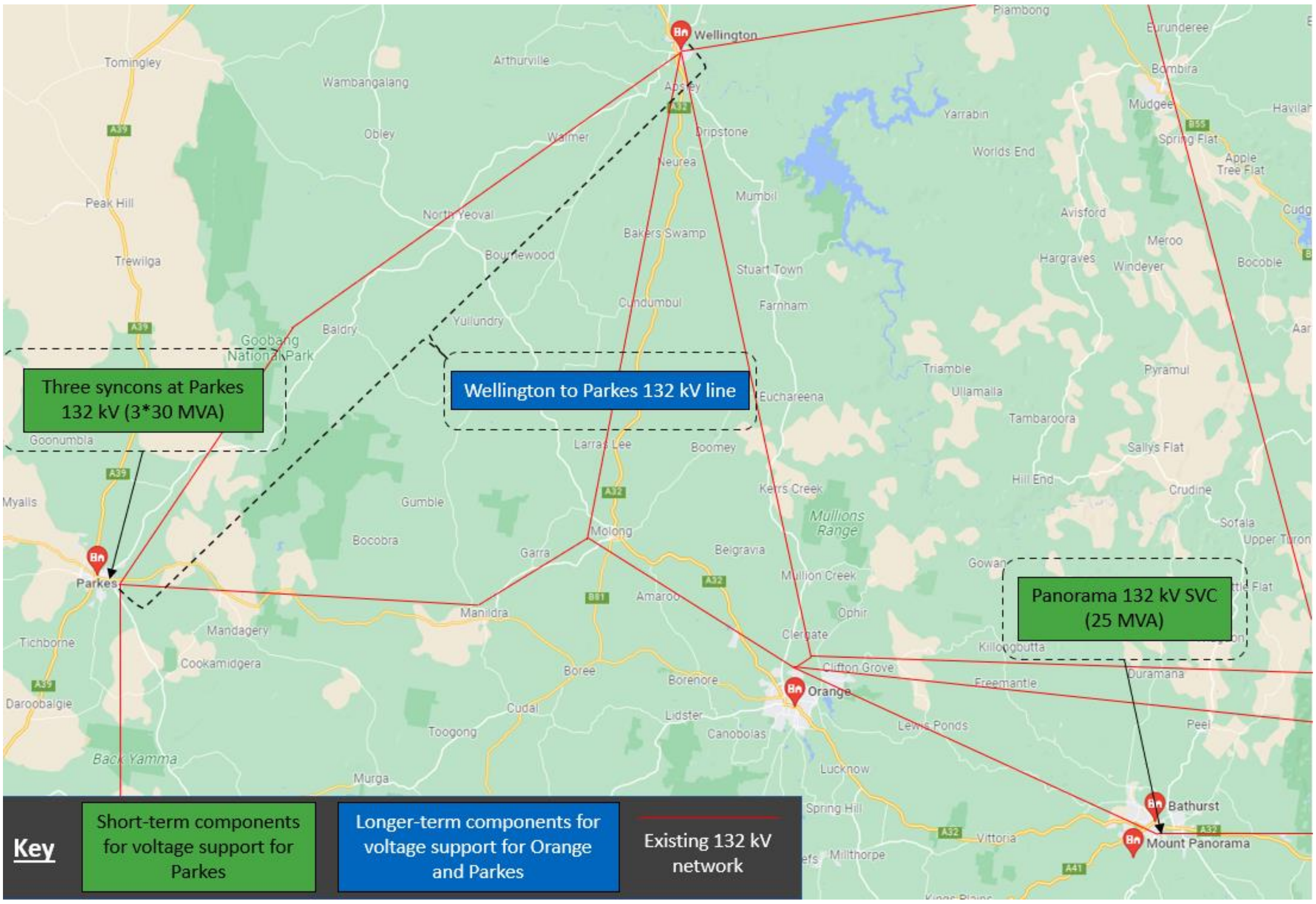


Table 4-7 summarises the expected construction time for each component.

Table 4-7: Summary of the expected construction time for each component of Option 3

Component	Expected construction time
Panorama 132 kV SVC (25 MVA) + synchronous condenser at Parkes 132 kV (3*30 MVA)	42 months
Wellington to Parkes 132 kV line	64 months

4.4. Option 4 – Reactive support at Panorama and Parkes ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)

Option 4 involves constructing:

- Panorama 132 kV SVC (25 MVA)[30] and three synchronous condensers at Parkes 132 kV (3*30 MVA);
- a new 330/132 kV substation at Orange (including two transformers and a 132kV line to the existing Orange North substation); and
- a fourth synchronous condenser at Parkes 132 kV (40 MVA), if required.

[30] Since the PSCR, we have considered SVCs, synchronous condensers and STATCOMs for this component and now assume an SVC since it has been found to be the lowest cost of the three choices (with the other two not expected to provide any additional benefits).

Table 4-8 summarises the optimal assumed timing for each component under the three different demand forecasts investigated.

Table 4-8: Summary of the assumed timing for each component of Option 4 across the forecasts

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
Panorama 132 kV SVC (25 MVA) and three synchronous condensers at Parkes 132 kV (3*30 MVA)	2026/27	2026/27	2026/27
Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	NA	2031/32	2027/28
A fourth synchronous condenser at Parkes 132 kV (40 MVA)	NA	NA	2027/28

Figure 9 below illustrates the type and location of the key elements for Option 4.

Figure 9: Overview of the key elements in Option 4

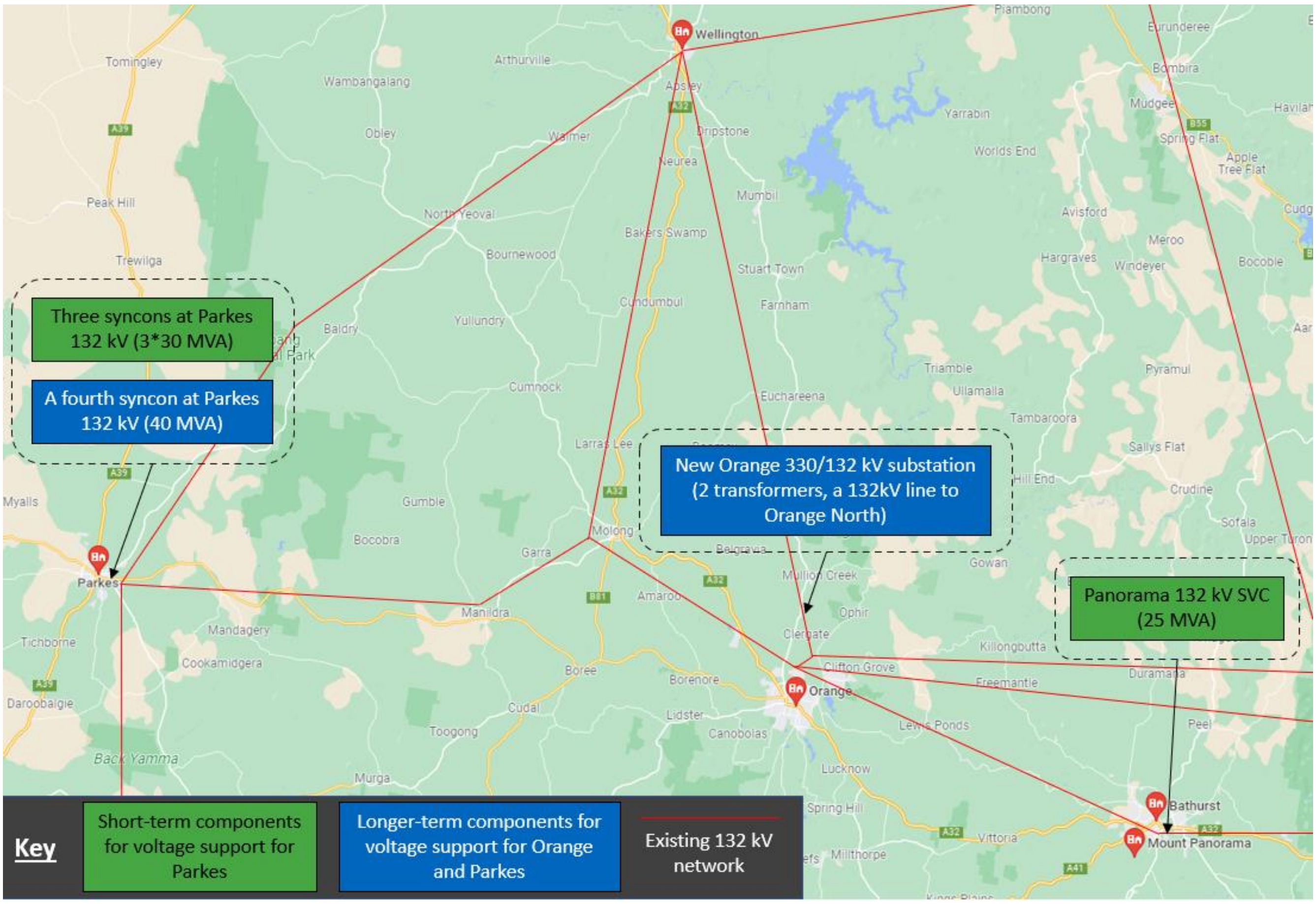


Table 4-9 summarises the expected construction time for each component.

Table 4-9: Summary of the expected construction time for each component of Option 4

Component	Expected construction time
Panorama 132 kV SVC (25 MVA) and three synchronous condensers at Parkes 132 kV (3*30 MVA)	42 months
Orange 330/132 kV substation (2 transformers, a 132kV line to Orange North)	59 months
A fourth synchronous condenser at Parkes 132 kV (40 MVA)	40 months

4.5. Option 5 – BESS at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 132 kV line from Wellington to Parkes (if required)

Option 5 involves constructing:

- Two 30 MVAr synchronous condensers at Parkes, a 15 MW (30 MWh) battery at Parkes and a 20 MW (40 MWh) battery at Panorama; and
- a new Wellington to Parkes 132 kV line, if required.

Batteries can generally be used for a number of grid support services. In this option (and in Option 6), it is expected that the batteries will output both active and reactive power. At times of high renewable generation and low demand in the area, the batteries can be charged and then can be discharged at times of high demand and low renewable generation. The batteries can also provide MVAr output to provide dynamic reactive support, particularly during system disturbances.

Option 5 assumes a network-owned battery (i.e., as distinct from the non-network options outlined below) and generic costs have been used to assess this option based on Transgrid's internal database.

Table 4-10 summarises the optimal assumed timing for each component under the three different demand forecasts investigated.

Table 4-10: Summary of the assumed timing for each component of Option 5 across the forecasts

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
Two 30 MVAr synchronous condensers at Parkes, a 15 MW (30 MWh) battery at Parkes and a 20 MW (40 MWh) battery at Panorama	2026/27	2026/27	2026/27
Wellington to Parkes 132 kV line	NA	2031/32	2027/28

Figure 10 below illustrates the type and location of the key elements for Option 5.

Figure 10: Overview of the key elements in Option 5

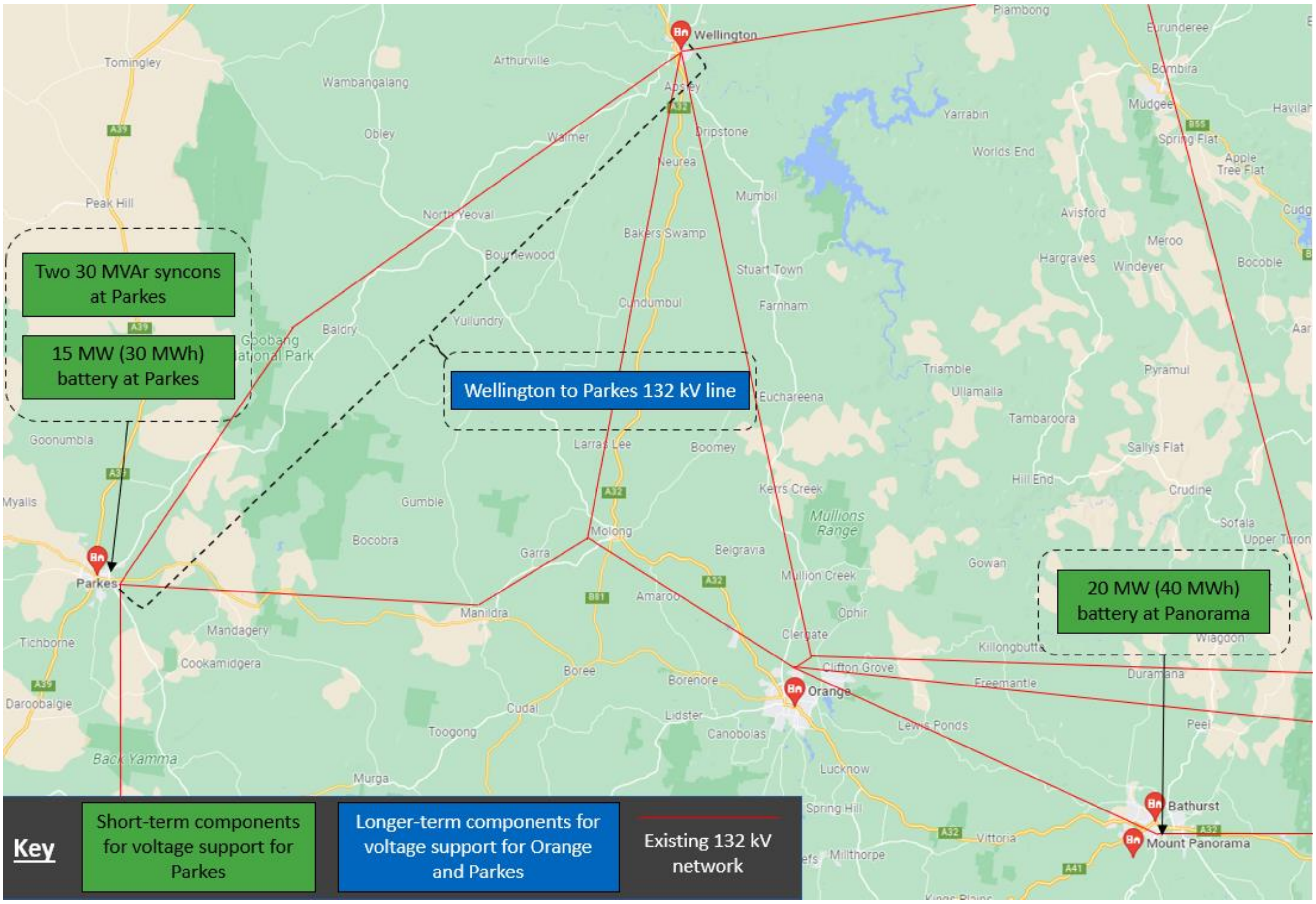


Table 4-11 summarises the expected construction time for each component.

Table 4-11: Summary of the expected construction time for each component of Option 5

Component	Expected construction time
2 x 30 MVAr synchronous condenser at Parkes + 15 MW (30 MWh) battery at Parkes + 20 MW(40 MWh) battery at Panorama	42 months
Wellington to Parkes 132 kV line	64 months

4.6. Option 6 – BESS at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)

Option 6 involves constructing:

- Two 30 MVAr synchronous condensers at Parkes, a 15 MW (30 MWh) battery at Parkes and a 20 MW (40 MWh) battery at Panorama;
- a new 330/132 kV substation at Orange (including two transformers and a 132kV line to the existing Orange North substation); and
- a third synchronous condenser at Parkes 132 kV (40 MVA), if required.

As with Option 5, Option 6 assumes a network-owned battery (i.e., as distinct from the non-network options outlined below) and generic costs have been used to assess this option based on Transgrid's internal database.

Table 4-12 summarises the optimal assumed timing for each component under the three different demand forecasts investigated.

Table 4-12: Summary of the assumed timing for each component of Option 6 across the forecasts

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
Two 30 MVAr synchronous condensers at Parkes, a 15 MW (30 MWh) battery at Parkes and a 20 MW (40 MWh) battery at Panorama	2026/27	2026/27	2026/27
New 330/132 kV substation at Orange (including two transformers and a 132kV line to the existing Orange North substation)	NA	2031/32	2027/28
Third synchronous condenser at Parkes 132 kV (40 MVA)	NA	NA	2027/28

Figure 11 below illustrates the type and location of the key elements for Option 6.

Figure 11: Overview of the key elements in Option 6

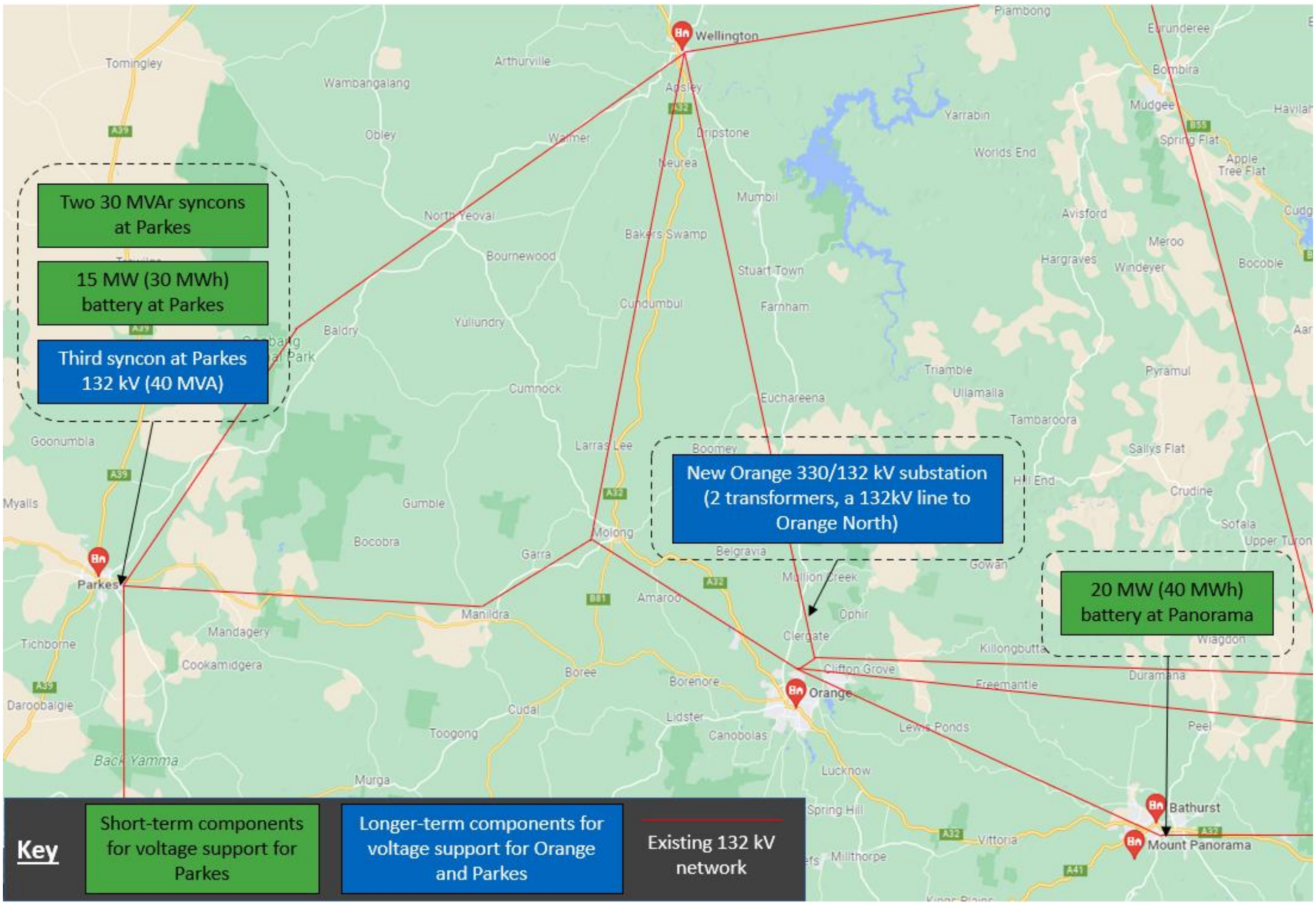


Table 4-11 summarises the expected construction time for each component.

Table 4-13: Summary of the expected construction time for each component of Option 6

Component	Expected construction time
Two 30 MVAr synchronous condensers at Parkes, a 15 MW (30 MWh) battery at Parkes and a 20 MW (40 MWh) battery at Panorama	42 months
New 330/132 kV substation at Orange (including two transformers and a 132kV line to the existing Orange North substation)	59 months
Third synchronous condenser at Parkes 132 kV (40 MVA	40 months

4.7. Option 7 – Non-network options

The non-network options use a combination of technologies to provide reactive support at Panorama and Parkes. In particular, Options 7A and 7B use BESS in combination with solar PV, Option 7C uses BESS only, while Option 7D uses BESS and synchronous condensers. We have not presented the complete detail regarding these options in order to preserve the confidentiality requested by proponents.

We have not exhaustively tested and confirmed the technical feasibility of the non-network elements put forward in response to the PSCR as part of this PADR. Doing so would require requesting additional information and modelling from the third party proponents and we note the costs and effort involved in providing this material, as well as a general desire from submitters to first understand whether their proposal is likely to be in the running for identification as part of the preferred option. We have consequently assumed that each non-network solution assessed is technically feasible for the purposes of the PADR and intend to undertake a full assessment of technical feasibility as part of the PACR.

Table 4-14 summarises the optimal assumed timing for these options under the three different demand forecasts investigated.

Table 4-14: Summary of the assumed timing for the components of Options 7A-7D

Component	Expected timing (low)	Expected timing (central)	Expected timing (high)
Non-network components	Confidential	Confidential	Confidential
Wellington to Parkes 132 kV line	NA	2031/32	2027/28

The timing assumed at this stage for each of the non-network options has been based on the submissions received from, and follow-up clarifications with, proponents. As outlined in section 8, we will be investigating and substantiating the expected timing of all options as part of the PACR analysis given the criticality of the assumed timing to the overall option ranking.

The non-network solutions are not considered to be long-term standalone solutions and, instead, provide alternate ways to provide reactive support at Panorama and/or Parkes for the preferred network option at this stage of the RIT-T (Option 3) in the short-term. We consider this represents a proportionate approach to considering these solutions for this RIT-T.

4.8. 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 4-15.

Table 4-15: Options considered but not progressed

Option	Reason(s) for not progressing
Capacitor banks/ switched capacitors	Not technically feasible. Due to the expected extensive load growth in the Parkes and Orange areas, adding a number of additional capacitor banks or switched capacitors in the area is considered to be a non-credible solution (even in light of the reduced demand forecasts since the PSCR). There are number of capacitor banks already in-service at Parkes, Orange and Panorama substations and further capacitor banks are shortly to be commissioned as part of separate Transgrid projects to address load growth in the medium-term. Installing further additional capacitor banks will lead to voltage control/regulation stability issues.
Constructing a new 330 kV line between Orange and Parkes (Option 2 from the PSCR).	Not commercially feasible. This option from the PSCR is no longer considered commercially feasible in light of the updated demand forecasts. It is expected to cost at least 60 per cent more than Option 3 and is not expected to provide any greater level of market benefit.

5. Ensuring the robustness of the analysis

The investments considered as part of this RIT-T involve long-lived assets, and it is important that the recommended preferred option does not depend on a narrow view of future outcomes, given that the future is inherently uncertain.

Uncertainty is captured under the RIT-T framework through the use of reasonable scenarios, which reflect different assumptions about future market development, and other factors that are expected to affect the relative market benefits of the options being considered. The adoption of different scenarios tests the robustness of the RIT-T assessment to different assumptions about how the energy sector may develop in the future.

The robustness of the outcome is also investigated through the use of sensitivity analysis in relation to key input assumptions. We have also identified the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for these factors, beyond which the outcome of the analysis would change.

5.1. The assessment considers three 'reasonable scenarios'

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit.[31] 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 PADR assessment, which differ in terms of the key drivers of the estimated net market benefits.

The three scenarios are characterised as follows:

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

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

[31] 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.

Table 5-1: Summary of scenarios

Variable	Central	Low net economic benefits	High net economic benefits
Network capital costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Demand	Central demand forecast (as outlined in section 2.2)	Low demand forecast (as outlined in section 2.2)	High demand forecast (as outlined in section 2.2)
New renewable generation in the area	In-service, commissioning and committed generators from Appendix B.	All in-service, commissioning, committed and advanced generators from Appendix B.	In-service, commissioning and committed generators from Appendix B.
Wholesale market benefits estimated	Estimated based on the 'progressive change' 2022 ISP scenario (as outlined in section 6.3 below)	30 per cent lower than central scenario estimate	30 per cent higher than central scenario estimate
VCR	$53.48/kWh	$37.44/kWh	$69.53/kWh
Discount rate	5.50%	7.50%	2.23%

5.2. Weighting the reasonable scenarios

We consider that the central scenario is most likely since it is based primarily on a set of expected assumptions. We have therefore assigned this scenario a weighting of 50 per cent, with the other two scenarios being weighted equally with 25 per cent each.

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

- the assumed timing of both the network and non-network components;
- a lower demand forecast for a key mining load under the low scenario;
- adopting the low demand forecast as part of the central scenario assumptions;
- lower assumed future reinvestment costs for batteries;
- differing network capital costs for the credible options; and
- alternate commercial discount rate assumptions.

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

In addition, as part of the analysis we have also identified the key factors driving the outcome of this RIT-T and sought to identify the 'threshold value' for key variables beyond which the outcome of the analysis would change.

The above list of sensitivities focuses on the key variables that could impact the identified preferred option.

6. Estimating the market benefits

As outlined in section 2, the key benefit expected from the options is avoided involuntary load shedding in central west NSW. In addition, for options that involve non-network components, 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 NEM outcomes expected in each case, and includes the location and quantity of load in central west NSW, 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 PADR assessment. Appendix D provides additional detail on the wholesale market modelling undertaken by EY. We are also publishing a separate modelling report prepared by EY alongside this PADR 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 PADR 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 Orange and Parkes areas are 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 2027/28 as part of the PADR analysis since each option will address all constraints equally from then on and so avoid the same amount of unserved energy thereafter. Quantifying the full extent of avoided involuntary load shedding under each option after 2027/28 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, if the full amounts are captured, they will dwarf the other quantified costs and benefits (e.g., we estimate that these will exceed $1.9 billion/year by 2026/27 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 2027/28. 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[32] and advice provided to the AER.[33]

6.2. Avoided involuntary load shedding in central west NSW

We have run system studies to estimate the Expected Unserved Energy (EUE) in central west NSW under each of the three 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.[34] Specifically, we have developed a load-weighted VCR estimate for the central scenario using the AER VCR values for the customer groups relevant to the region. We have then applied VCR estimates that are 30 per cent lower and 30 per cent higher for the low and high scenarios, respectively, consistent with the AER's specified +/- 30 per cent confidence interval.[35]

The EY market modelling has also quantified the impact of changes in involuntary load shedding *outside* of central west NSW 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 central west NSW for each option. However, these estimated changes in EUE are not expected to be material for any of the credible options.

6.3. Wholesale market benefits

As outlined in section 2.3, six of the credible options assessed in this PADR involve the use of BESS that are expected to be able to assist with providing reactive support in the short-term and to also use a portion of their capacity to dispatch to the wholesale market. Dispatching to the wider market 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.[36]

These wider benefits have been estimated by way of wholesale market modelling conducted by EY. For the purposes of the PADR assessment we have made a key assumption, which is favourable to these options, that these components are able to use their *entire* capacity to dispatch in the NEM (when, in reality, only a portion would be able to be offered into the NEM, as some BESS capacity would need to be reserved to provide network support). We will be working with proponents to revise this assumption ahead of the PACR.

The relevant credible options have been assessed using a set of market modelling assumptions based on the 'progressive change' scenario identified and consulted on by AEMO for the 2022 ISP. We consider focussing on one ISP scenario to be a proportionate approach, since our results indicate that the wholesale market benefits do not have a bearing on the identification of the preferred option, with the ranking instead being driven by the timing, and so avoided unserved energy, differences across the options, as outlined in section 7 below.

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32 ENA, *RIT-T Economic Assessment Handbook for non-ISP RIT-Ts*, Version 2.0, 26 October 2020, p. 51.
33 Biggar, D., *An Assessment of the Modelling Conducted by TransGrid and Ausgrid for the 'Powering Sydney's Future' Program*, May 2017, pp. 12-16.
34 The VCR values have been taken from the most recent VCR update from the AER, i.e.: AER, *Annual update – VCR review final decision – Appendices A – E*, December 2021.
35 AER, *Values of Customer Reliability – Final Report on VCR values*, December 2019, p. 84.
36 While the other credible network options (i.e., the solely network options) will provide additional system strength around Parkes and/or relieve emerging line constraints around Bathurst and Orange, we do not consider there to be material wholesale market benefits associated with these options as outlined in section 2.3.

AEMO has assigned the ‘progressive scenario’ a 29 per cent weighting in its draft 2022 ISP, released on 10 December 2021. This is slightly below the ‘step change’ scenario, to which AEMO has assigned a 50 per cent weighting and which it notes is considered by energy industry stakeholders to be the most likely scenario to play out.[37] We intend to update the market modelling in the PACR to be based on the step change scenario (despite the PADR modelling finding that the estimated market benefits are not material to the outcome).[38]

While the EY market modelling for this RIT-T focusses on the progressive change ISP scenario, we have also applied a broad assumption of 30 per cent lower and 30 per cent higher aggregate wholesale market benefits as part of the low and high scenario investigated, respectively. This 30 per cent does not represent any sort of confidence level for the market modelling conducted by EY but, instead, has been instigated by us as a proportionate approach to further test the robustness of the preferred option.

Appendix D summarises the key variables under the progressive change scenario 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 6-1 below summarises the specific categories of wholesale market benefit under the RIT-T that have been modelled as part of this PADR.

Table 6-1: Categories of wholesale market benefit under the RIT-T that have been modelled as part of this PADR

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 non-network components have been captured in the PADR assessment as a cost to other parties, reflecting that this is an additional resource cost to the NEM that would not be incurred if we did not sign a network support agreement with the proponents for these options (as these projects are not already committed or anticipated). This is consistent with the AER’s revised guidance on the treatment of NNO.[39] 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.

[37] AEMO, *Draft 2022 Integrated System Plan*, December 2021, pp. 25-26 & 29.
[38] We initially modelled the market benefits for this PADR using AEMO’s ‘steady progress’ 2022 ISP scenario, which AEMO noted in the 2021 Inputs, Assumptions and Scenarios Report (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 this RIT-T over December 2021 and January 2022 to be based on the progressive change scenario (time would not permit updating to the step change scenario).
[39] AER, *Guidelines to make the Integrated System Plan actionable*, Final decision, August 2020, p. 26.

Market benefit	Overview
Changes in network losses	The time sequential market modelling has taken into account the change in network losses that may be expected to occur as a result of the implementation of each of the credible options, compared with the level of network losses which would occur in the base case, for each scenario. The benefit of changes to network losses is captured within the wholesale market modelling of dispatch cost benefits of avoided fuel costs and changes to voluntary and involuntary load shedding. The reduction in network losses between the base case and the options is considered immaterial for the options considered in this PADR but reduces both the energy to be produced by fossil fuel generators to account for the losses, and a reduction in new capacity that has to be built to supply demand, particularly during peak periods.
Differences in unrelated transmission costs	This benefit category relates to the costs of intra-regional transmission investment associated with the development of REZ that could be avoided if a credible option is pursued. AEMO has identified a number of REZ in various NEM jurisdictions as part of the ISP and has included allowances for transmission augmentations that it considers would be required to develop those REZ. 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 central west NSW)	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.
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.

6.4. General modelling parameters adopted

The RIT-T analysis spans a 20-year assessment period from 2021/22 to 2040/41.[40]

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

A real, pre-tax discount rate of 5.50 per cent has been adopted as the central assumption for the NPV analysis presented in this PADR, consistent with the assumptions adopted in 2021 Inputs, Assumptions and Scenarios (IASR). The RIT-T also requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have therefore tested the sensitivity of the results to a lower bound discount rate of 2.23 per cent,[41] and an upper bound discount rate of 7.50 per cent (i.e., the upper bound proposed for the 2022 ISP[42]).

6.5. Classes of market benefit not considered material

The NER requires that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific category (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option.[43]

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 central west NSW 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 being considered are sufficiently flexible to respond to that change. The credible options outlined in this PADR 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.

[40] This has been updated since the PSCR (which stated a 20 year assessment period would be used) as market modelling was not contemplated at the time of the PSCR.
[41] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/directlink-determination-2020-25
[42] AEMO, *2021 Inputs, Assumptions and Scenarios Report*, July 2021, p. 105.
[43] NER clause 5.16.1(c)(6).

7. Net present value results

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

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 7A, Option 7B, Option 7C and Option 7D (i.e., the present value of the aggregate market benefits estimated less the present value of the aggregate costs).

The accompanying market modelling report provides additional detail in terms of the modelled wholesale market impacts for each option modelled. Neither this PADR nor the accompanying market modelling report provide the estimated wholesale market benefits of the non-network options in dollar terms, in order to protect the confidentiality of the options assessed.[44]

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. Central scenario

The central scenario reflects our central view of key underlying assumptions and is considered the most likely scenario in terms of the net market benefits for each of the options. These assumptions include central demand forecasts, network cost estimates, VCR and commercial discount rate estimates. This scenario also includes EY's market modelling of the wholesale market benefits for the non-network options based on the 'progressive change' scenario to be used in the 2022 ISP.

Under these assumptions, the options involving non-network solutions in the short-term (i.e., Option 7A, Option 7B, Option 7C and Option 7D) are strongly preferred over the solely network options. This is primarily due to these options being able to be commissioned approximately two to four years before the network options, which allows them to avoid substantial additional unserved energy in these earlier years.

While Option 7D is the top-ranked option overall, the options involving non-network solutions are found to have net benefits all within 3 per cent of each other and so are not considered materially different.

Similarly, all the solely network options (with the exception of Option 1A/1B) are also found to have net benefits all within 3 per cent of each other and so are not considered materially different.

Figure 7-12 shows the overall estimated net benefit for each option under the central scenario. All figures of this format in the PADR show the top-ranked option(s) in green, and the other options in blue.

[44] Further, neither this PADR nor the accompanying market modelling report present the estimated wholesale market benefits of the Transgrid-owned BESS options (Option 5 and Option 6) to avoid any inferences being made regarding the costs (or benefits) of the non-network options.

Figure 7-12: Summary of the estimated net benefits under the central scenario

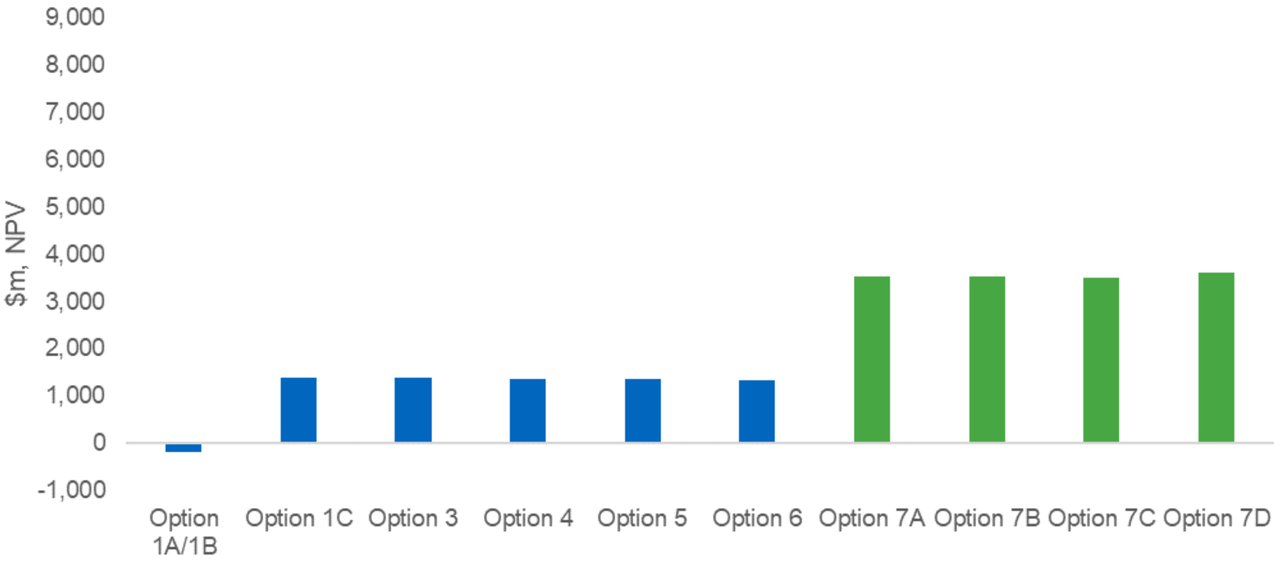
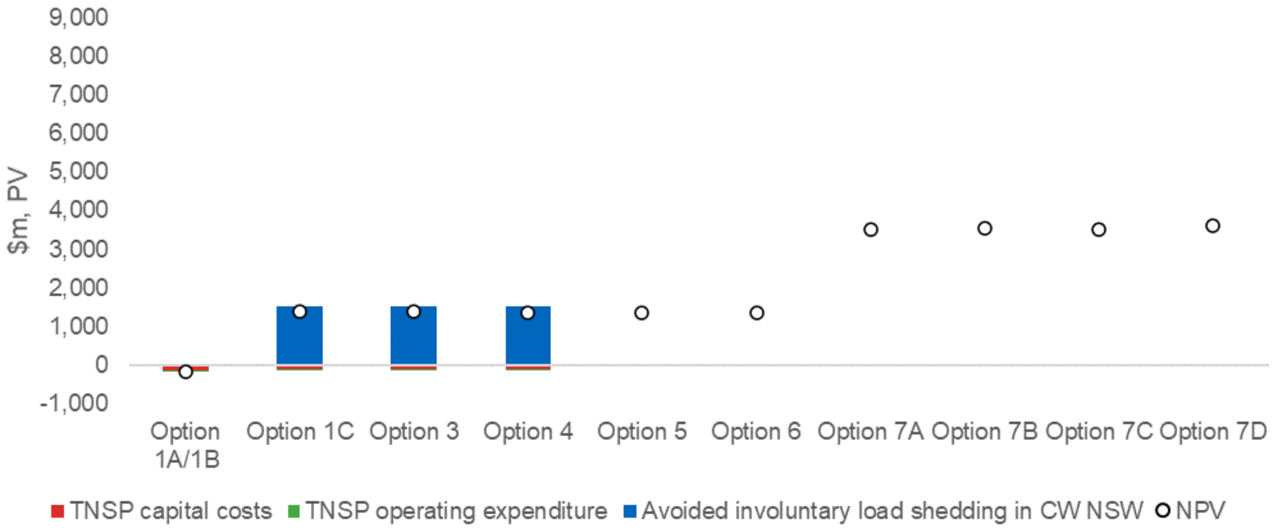


Figure 7-13 shows the composition of estimated net benefits for each option under the central scenario. Only the net numbers are shown for Option 7A, Option 7B, Option 7C and Option 7D in order to protect the confidentiality of these options. Option 5 and Option 6 (the Transgrid-owned BESS options) have also been redacted to avoid any inferences being made regarding the costs (or benefits) of the non-network options.

Figure 7-13: Breakdown of estimated net benefits under the central scenario



The wholesale market modelling for the non-network options finds that the primary sources of benefit are from avoided and deferred capex for new generation/storage and avoided fuel cost savings. The wholesale market benefits are found to make up between 0.9 and 7.3 per cent of the total estimated gross benefit for these options and are found to not be material overall in the assessment to the finding that the options involving non-network solutions in the short-term are strongly preferred over the solely network options (i.e., if these sources of market benefits were removed from the analysis, this conclusion would not change). However, the wholesale market benefits are found to be material to *which* of the non-network options is preferred and, if the wholesale market benefits are removed from the analysis, Option 7D becomes the uniquely preferred option under this scenario (with net benefits that are approximately 6 per cent greater than the second-ranked option (Option 7A)).

7.2. Low net economic benefits

The low net economic benefits scenario reflects a number of assumptions that gives a lower bound and conservative estimate of net present value of net economic benefits. These assumptions include the low demand forecast, high network cost estimates, low VCR and a high commercial discount rate estimate. This scenario also includes 30 per cent lower wholesale market benefits than those estimated by EY as an additional robustness test for the option rankings.

Under these assumptions, all options are found to have marginally negative net benefits. However, we note that this scenario is considered an extreme scenario, given the combination of assumptions it involves, and also that the RIT-T permits the preferred option to have negative net market benefits for a reliability corrective action. Further, we note that the avoided unserved energy benefits are capped in the PADR analysis to remove unserved energy that does not contribute to identifying the preferred option (as outlined in section 6.1) and, if the full avoided unserved energy benefit was modelled, the net benefits of all options would increase (with the top-ranked option (Option 7D) having marginally positive net benefits of $24 million).

The relativities between the options also changes under this scenario, compared to the central scenario. Specifically, the purely network options (i.e., Option 1A/1B, Option 1C, Option 3, Option 4, Option 5 and Option 6) are preferred over the options involving non-network solutions, with the exception of Option 7D (which has the lowest net cost of all options).

Figure 7-14 shows the overall estimated net benefit for each option under the low economic benefits scenario.

Figure 7-14: Summary of the estimated net benefits under the low economic benefits scenario

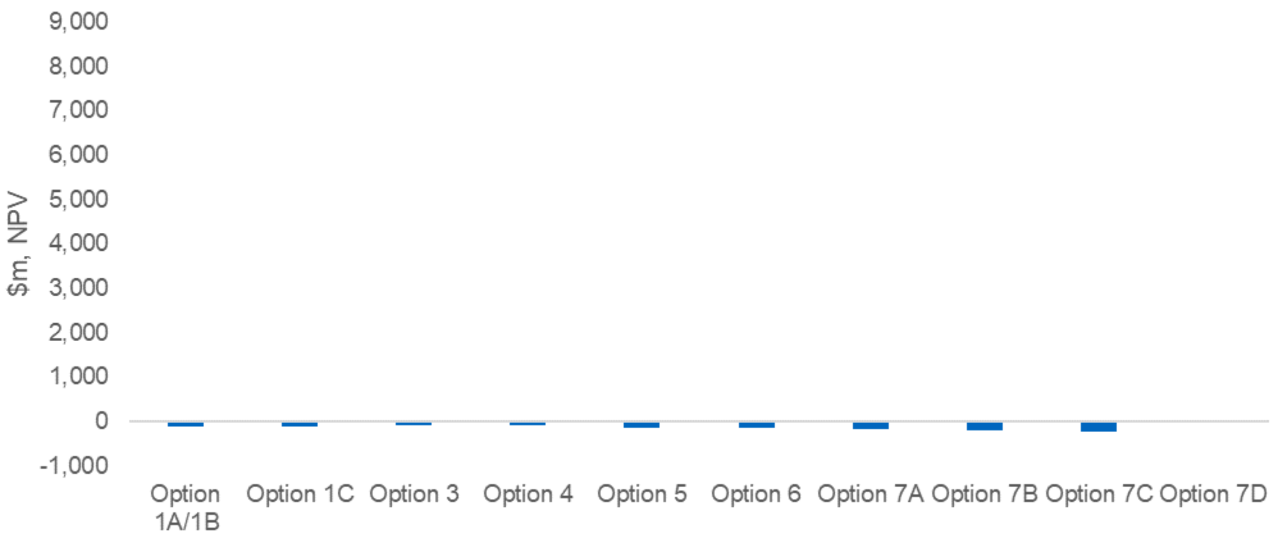
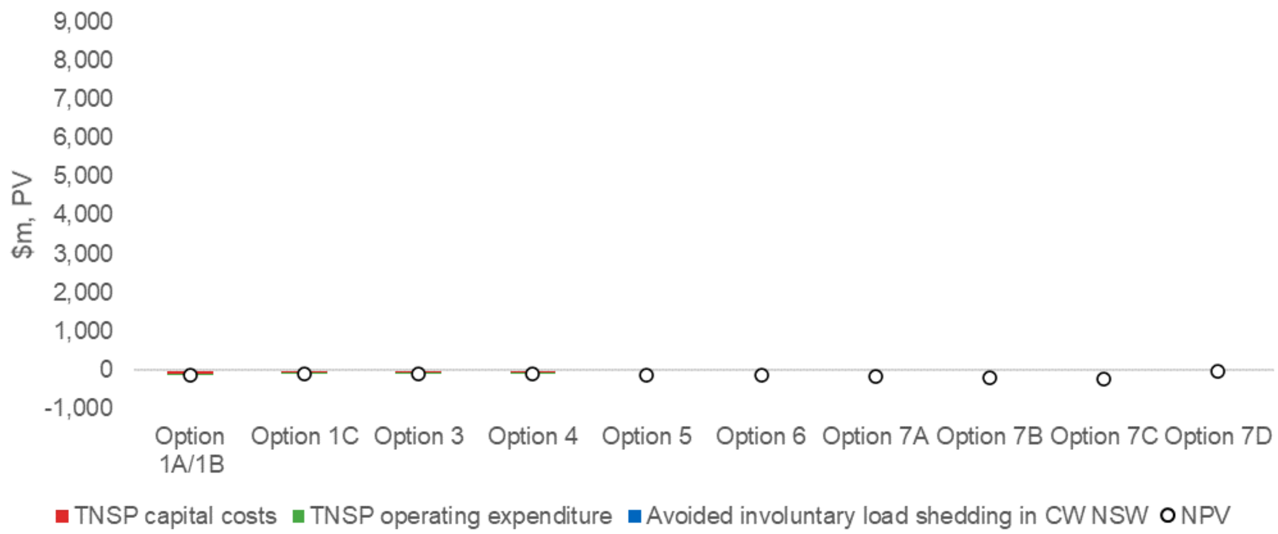


Figure 7-15 shows the composition of estimated net benefits for each option under this scenario. Only the net numbers are shown for Option 7A, Option 7B, Option 7C and Option 7D in order to protect the confidentiality of these options. Option 5 and Option 6 (the Transgrid-owned BESS options) have also been redacted to avoid any inferences being made regarding the costs (or benefits) of the non-network options.

Figure 7-15: Breakdown of estimated net benefits under the low economic benefits scenario



In contrast to the central scenario, the wholesale market benefits make up between 87 and 98 per cent of the total estimated gross benefit for the non-network options in the low scenario. However, the wholesale market benefits are found to not affect the ranking of the options under the low scenario, i.e., if these sources of market benefits were removed from the analysis, the ranking of the options would not change under this scenario.

7.3. High net economic benefits

The high net economic benefits scenario reflects a number of assumptions that gives an upper bound estimate of net present value of net economic benefits. These assumptions include the high demand forecast, low network cost estimates, high VCR and a low commercial discount rate estimate. This scenario also includes 30 per cent higher wholesale market benefits than those estimated by EY as an additional robustness test for the option rankings.

Under these assumptions, as with the central scenario, the options involving non-network solutions in the short-term (i.e., Option 7A, Option 7B, Option 7C and Option 7D) are strongly preferred over the solely network options. This is again due to these options being able to be commissioned approximately two to four years before the network options, which allows them to avoid substantial additional unserved energy.

While Option 7B is the top-ranked option overall, the options involving non-network solutions are found to have net benefits all within 1.3 per cent of each other and so are not considered materially different.

Similarly, all the solely network options (with the exception of Option 1A/1B and Option 1C) are also found to have net benefits all within 1.1 per cent of each other and so are not considered materially different. In contrast to the central scenario, the net benefits of Option 1C are approximately 9 per cent lower than Option 3 under the high scenario on account of Option 1C avoiding unserved energy slightly later in the period than Option 3.

Figure 7-16 shows the overall estimated net benefit for each option under the high economic benefits scenario.

Figure 7-16: Summary of the estimated net benefits under the high economic benefits scenario

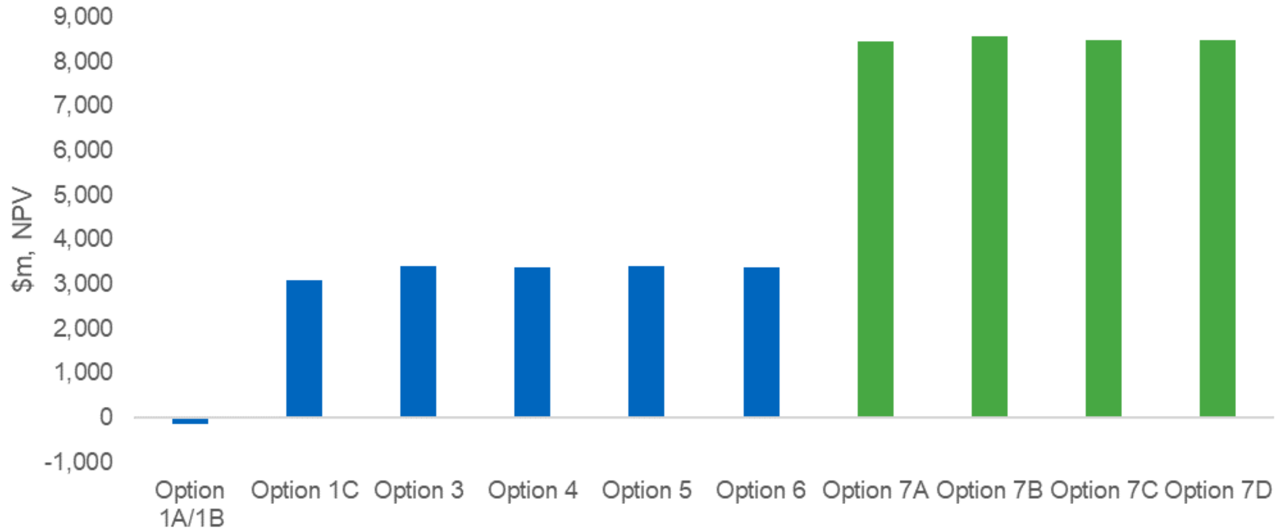
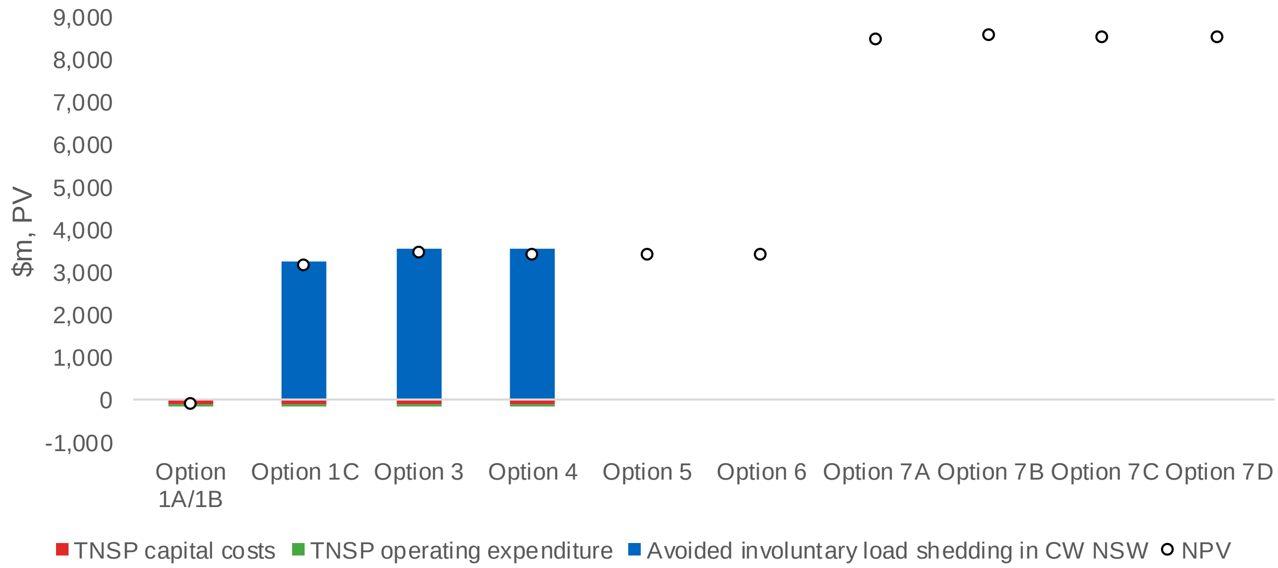


Figure 7-17 shows the composition of estimated net benefits for each option under this scenario. Only the net numbers are shown for Option 7A, Option 7B, Option 7C and Option 7D in order to protect the confidentiality of these options. Option 5 and Option 6 (the Transgrid owned BESS options) have also been redacted to avoid any inferences being made regarding the costs (or benefits) of the non-network options.

Figure 7-17: Breakdown of estimated net benefits under the high economic benefits scenario



The wholesale market benefits are found to make up between 0.6 and 5.4 per cent of the total estimated gross benefit for the non-network options under this scenario and are found to not be material overall in the assessment to the finding that the options involving non-network solutions in the short-term are strongly preferred over the solely network options. However, the wholesale market benefits are found to be material to *which* of the non-network options is preferred and, if the wholesale market benefits are removed from the analysis, Option 7A, Option 7B and Option 7D would all be ranked equal first, with Option 7C the lowest ranked of these options (having net benefits approximately 5 per cent lower than the top-ranked non-network options).

7.4. Weighted net benefits

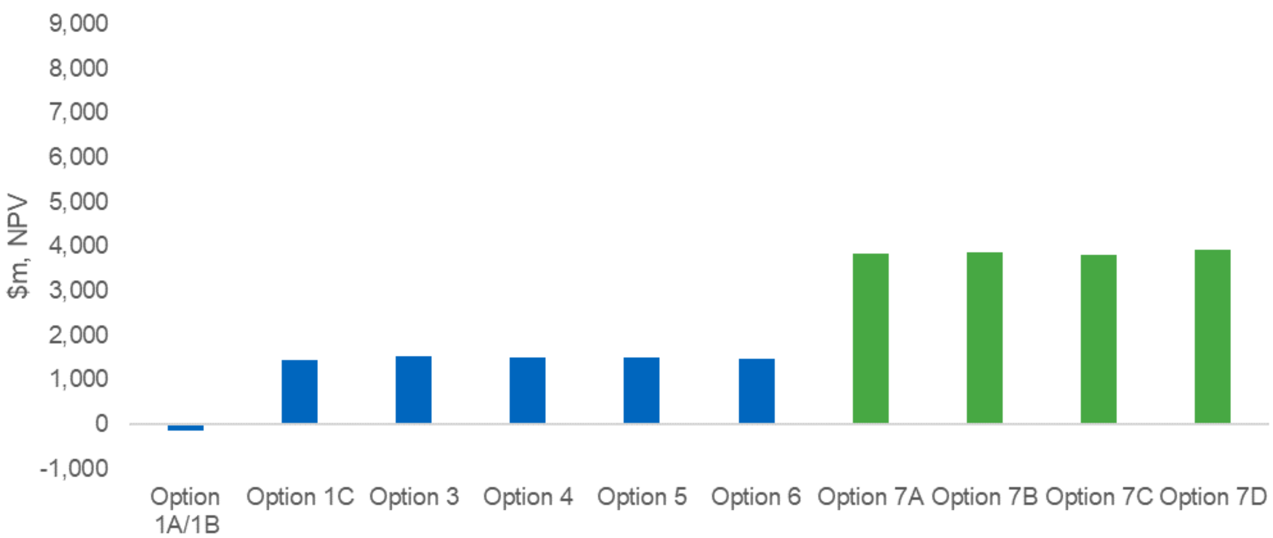
Figure 7-18 shows the estimated net benefits for each of the credible options weighted across the three scenarios investigated (and discussed above).

We consider that the central scenario is most likely since it is based primarily on a set of expected assumptions. We have therefore assigned this scenario a weighting of 50 per cent, with the other two scenarios being weighted equally with 25 per cent each.

Under the weighted outcome, the options involving non-network solutions in the short-term (i.e., Option 7A, Option 7B, Option 7C and Option 7D) are strongly preferred over the solely network options. While Option 7D is the top-ranked option overall, the options involving non-network solutions are found to have net benefits all within 2.5 per cent of each other and so are not considered materially different.

Similarly, all the solely network options (with the exception of Option 1A/1B and Option 1C) are found to have net benefits all within 2.7 per cent of each other and so are not considered materially different. While Option 3 is found to have net benefits that are approximately 1 per cent greater than the next best network option (Option 4), it is found to have the lowest expected capital cost of all the solely network options (5 per cent lower than Option 1C and 12 per cent lower than Option 4 (the two next lowest cost network options)), which is why it is considered the preferred network option and is the network option the non-network options have been coupled with.

Figure 7-18: Summary of the estimated net benefits, weighted across the three scenarios



We consider the key determinant of the overall preferred option to be 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 (where alternate assumed timings for Option 3 and Option 7D are tested) and will be a key focus in refining the analysis as part of the PACR (as outlined in section 8).

In addition, and as shown across the three separate scenarios investigated above, we find that the wider wholesale market benefits are material to which of the non-network options is top-ranked. We will therefore be working with proponents to refine the assessment of these benefits in the PACR.

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

- the assumed timing of both the network and non-network components;
- a lower demand forecast for a key mining load under the low scenario;
- adopting the low demand forecast as part of the central scenario assumptions;
- lower assumed future reinvestment costs for batteries;
- differing network capital costs for the credible options; and
- alternate commercial discount rate assumptions.

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

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. Assumed timing of the network and non-network components

As outlined in section 7.4, the 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 in earlier years.

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 regarding the additional benefit from including a non-network component is affected.

The two tables below investigate the effects of assuming earlier commissioning dates for the top-ranked solely network option (Option 3) as well as assuming later commissioning dates for the top-ranked option involving non-network components (Option 7D – where this is a proxy for the other non-network solutions given their materially similar net market benefit). Specifically, Table 7-1 shows the difference in dollars between Option 7D and Option 3 under various alternate timing assumptions, while Table 7-2 shows the estimated net benefits of Option 7D as a percentage of the estimated net benefits of Option 3 under the various alternate timing assumptions.

Table 7-1: Difference between Option 7D and Option 3 under timing sensitivities ($m, NPV), weighted

	Option 7D - No change	Option 7D - 1 year delay	Option 7D - 2 year delay
Option 3 - no change	2402.8	2401.8	1930.1
Option 3 - 1 year forward	539.3	538.3	66.6
Option 3 - 2 years forward	69.2	68.2	-403.5

Black text shows where Option 7D is preferred, while red text indicates where Option 3 is preferred.

Table 7-2: Estimated net benefits of Option 7D as a percentage of the estimated net benefits of Option 3 under timing sensitivities (%), weighted

	Option 7D - No change	Option 7D - 1 year delay	Option 7D - 2 year delay
Option 3 - no change	258.4%	258.3%	227.2%
Option 3 - 1 year forward	116.0%	115.9%	102.0%
Option 3 - 2 years forward	101.8%	101.8%	89.5%

Black text shows where Option 7D is preferred, while red text indicates where Option 3 is preferred.

Both tables above show that the conclusion that options involving non-network solutions in the short-term are strongly preferred over the solely network options is relatively robust. There would need to be a two year delay to the commissioning of the BESS under Option 7D combined with a two year bringing forward of Option 3 in order for Option 3 to be preferred (and, even under these assumptions, Option 3's net benefits would only be approximately 10 per cent greater than Option 7D's).

Outside of the assumed combined two year delay/bringing forward, we find that the only sensitivities to result in Option 3 being within 5 per cent of Option 7D are when:

- Option 3 is assumed to be brought forward two years (and Option 7D is assumed to either have no change to its timing, or be delayed by one year); and
- Option 3 is assumed to be brought forward by one year and Option 7D is delayed by two years.

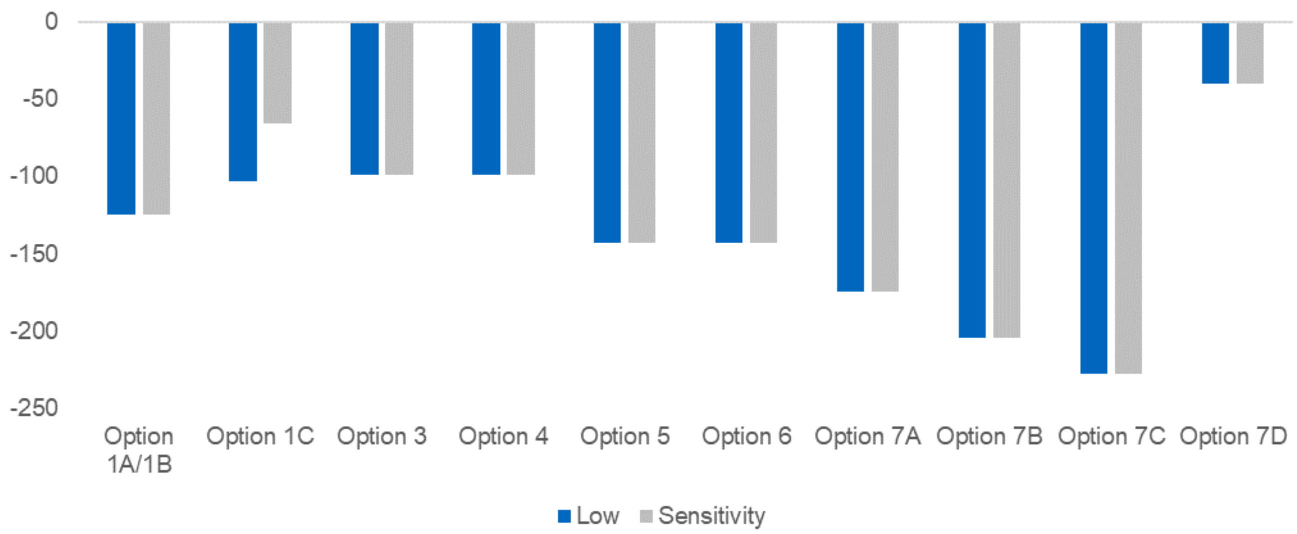
Overall, while delaying the commissioning of Option 7D makes a difference to the relativities between these two options, we find that bringing forward the network option makes a larger difference due to the ramping up of expected spot load (and so avoided unserved energy) over time.

7.5.2. A lower demand forecast for a key mining load under the low scenario

While the core results assume that the full expected capacity of a key mining load comes online, we have also considered a sensitivity that relaxes this assumption and instead assumes only 50 per cent of the load comes on line (which we consider less likely than the full amount given where the party is at with the connection process).

Figure 7-19 shows the results of this sensitivity for the low scenario and, specifically, that it does not change the key findings under this scenario, i.e., that Option 7D is uniquely preferred and the other options involving non-network solutions rank below the solely network options (as summarised in section 7.2 above). The only change is that the second stage of Option 1C is further delayed in this version of the low scenario meaning that it has lower costs, in present value terms, and so becomes the top-ranked network option in the low scenario over Option 3 and Option 4 (although still has significantly negative net benefits[45]).

Figure 7-19: Impact of a 50 per cent lower assumed key load, low scenario



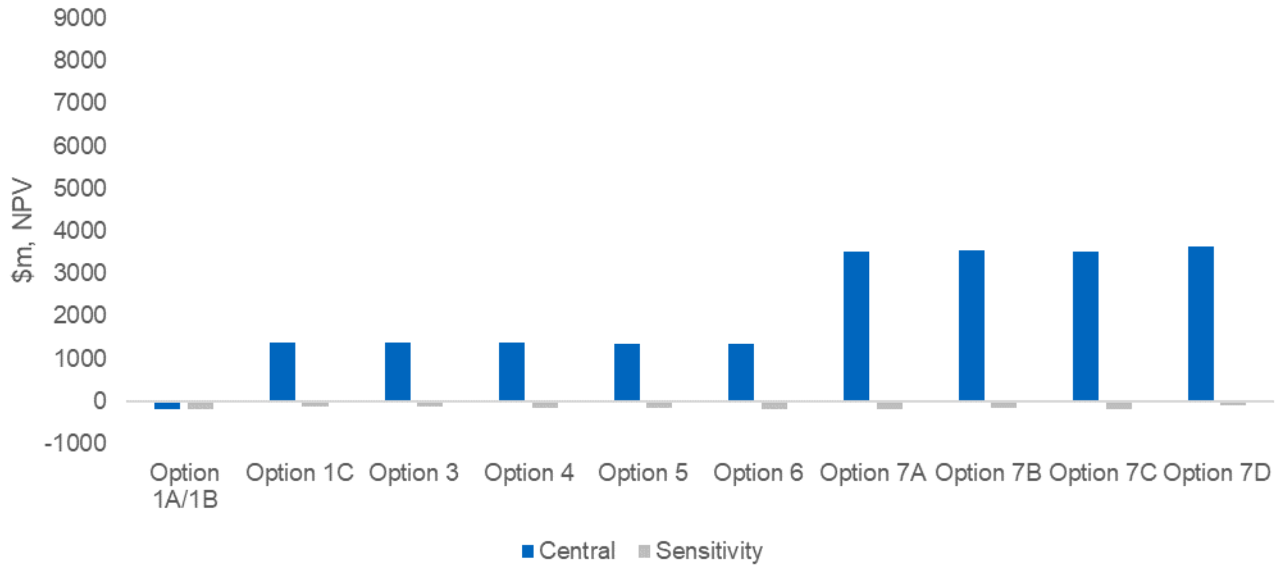
7.5.3. Central scenario but assuming the low demand forecast

Figure 7-20 shows the effect of assuming the low demand forecasts for the central scenario. Specifically, it keeps all assumptions under the central scenario the same with the exception of the demand forecast (where the low forecast is used).

Under these assumptions, all options are found to have net costs, meaning that they are not preferred over the base case 'do nothing' option (as is the case for the core low benefits scenario). While this illustrates how significant the assumed spot loads are to the level of net benefits expected, we note that, as with the core low scenario, Option 7D would have positive net benefits if the full amount of unserved energy was captured in this sensitivity (all other options, including Option 3, would have negative net benefits though). Moreover, we note that the preferred option for a reliability corrective action is able to have negative net benefits under the RIT-T.

[45] However, we note that, as with the core low scenario, all options would have positive net benefits if the full amount of unserved energy was captured in this sensitivity.

Figure 7-20: Impact of assuming the low demand forecast in the central scenario

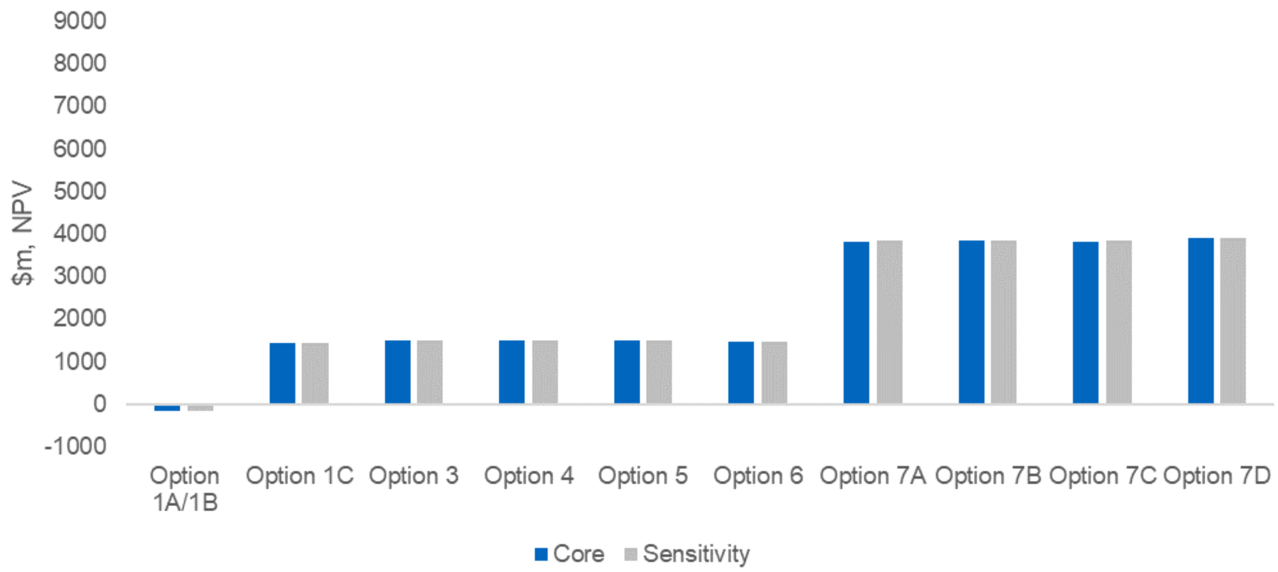


7.5.4. Lower assumed reinvestment cost for batteries

The modelling assumes that batteries are reinvested in over the assessment period, since their asset lives are shorter than the assessment period. The core analysis assumes that this re-investment occurs at the same real cost as the initial investment. This sensitivity tests the effect of assuming a lower real reinvestment cost in light of these costs likely decreasing going forward as technologies mature.

Figure 7-21 shows the effect of assuming an indicative 25 per cent real cost reduction for battery reinvestment. It shows that the core results are not sensitive to the assumed reinvestment cost for batteries.

Figure 7-21: Impact of assuming 25 per cent lower reinvestment battery costs, weighted outcome

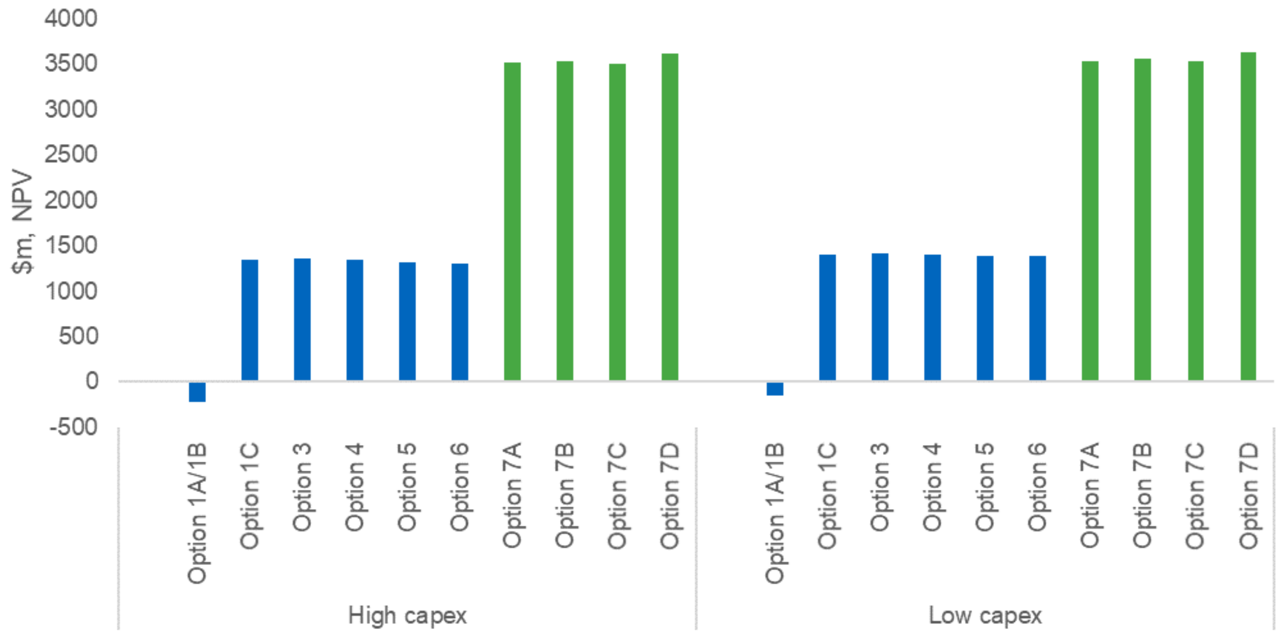


7.5.5. Network capital costs of the credible options

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

Figure 7-22 shows both 25 per cent higher and 25 per cent lower assumed capital costs under the central scenario.

Figure 7-22: Impact of 25 per cent higher and lower network capital costs, central scenario



Neither sensitivity changes the finding that the non-network options are preferred over the network options. In addition, neither sensitivity changes the finding that Option 3 is the preferred network option.

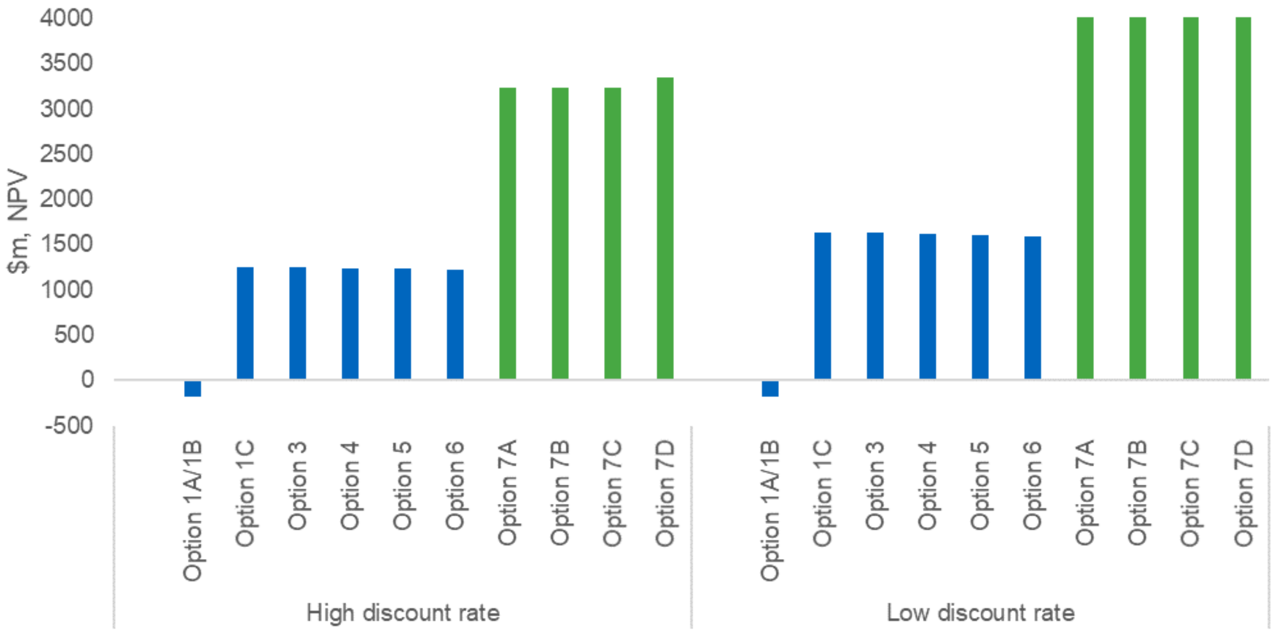
We further find that even if network costs (including the network cost elements of the non-network options) were assumed to be zero, Option 7D would still be preferred over Option 3 on account of the additional unserved energy it avoids.

7.5.6. Commercial discount rate assumptions

Figure 7-23 illustrates the sensitivity of the results to different discount rate assumptions in the NPV assessment under the central scenario. In particular, it illustrates two tranches of net benefits estimated for each credible option – namely:

- a high discount rate of 7.50 per cent; and
- a low discount rate of 2.23 per cent.

Figure 7-23: Impact of different assumed discount rates, central scenario



Neither sensitivity changes the finding that the non-network options are preferred over the network options. In addition, neither sensitivity changes the finding that Option 3 is the preferred network option.

We further find that there is no realistic discount rate that would result in Option 3 being preferred over Option 7D.

8. Conclusion

The results of the PADR assessment find that the options involving non-network solutions in the short-term coupled with the preferred network option in the long term (i.e., Option 7A, Option 7B, Option 7C and Option 7D) are strongly preferred over the solely network options. The options involving non-network solutions in the short-term are found to deliver estimated net benefits of approximately $3.8 billion to $3.9 billion overall relative to the base case 'do nothing' option on a weighted basis, which compares to $1.5 billion for the top-ranked solely network option (Option 3).

While Option 7D is the top-ranked option overall on a weighted basis, the options involving non-network solutions are found to have net benefits all within 2.5 per cent of each other and so are not considered materially different.

At this stage of the RIT-T, the preferred options are therefore the options involving non-network solutions in the short-term coupled with a new 132 kV line between Wellington and Parkes. These options are considered to satisfy the RIT-T at this draft stage and are summarised in the table below.

Table 8-1: Summary of the preferred options at this stage

<table>
<tr><th>Option</th><th>Description</th><th>Estimated capex ($2020/21)</th><th>Timing</th></tr>
<tr><td>7A</td><td>• Solar PV and BESS at Parkes
• BESS at Panorama
• Wellington to Parkes 132 kV line</td><td rowspan="4">• Confidential for the non-network components (including the synchronous condensers)
• $121 million for the line</td><td rowspan="4">• Confidential for the non-network components
• 2031/32 for the line under the central demand forecasts
• 2027/28 for the line under the high demand forecasts
• The line is not required under the low demand forecasts</td></tr>
<tr><td>7B</td><td>• Solar PV and BESS at Parkes
• BESS at Panorama
• Wellington to Parkes 132 kV line</td></tr>
<tr><td>7C</td><td>• BESS at Parkes
• BESS at Panorama
• Wellington to Parkes 132 kV line</td></tr>
<tr><td>7D</td><td>• BESS at Parkes
• BESS at Panorama
• 2 x 42.5 MVA synchronous condensers at Parkes
• Wellington to Parkes 132 kV line</td></tr>
</table>

We consider that 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. We will therefore be focussing, internally and with third party proponents of non-network solutions, to firm up the assumed commissioning dates (and costs) for all options between now and the PACR, and to ensure that the assumed option timing is realistic in all cases. We expect that factors such as the assumed timing of land acquisition and planning approvals will be key to firm up and note that the current proposals display some diversity across these assumptions. It is expected that the assumed option timings in the PACR will reflect what option proponents are willing to commit to.

In addition, the wholesale market benefits estimated are found to be material to which of the non-network options is the top-ranked option and so we will be working with proponents to refine the assessment of these benefits in the PACR.

Appendix A Compliance checklist

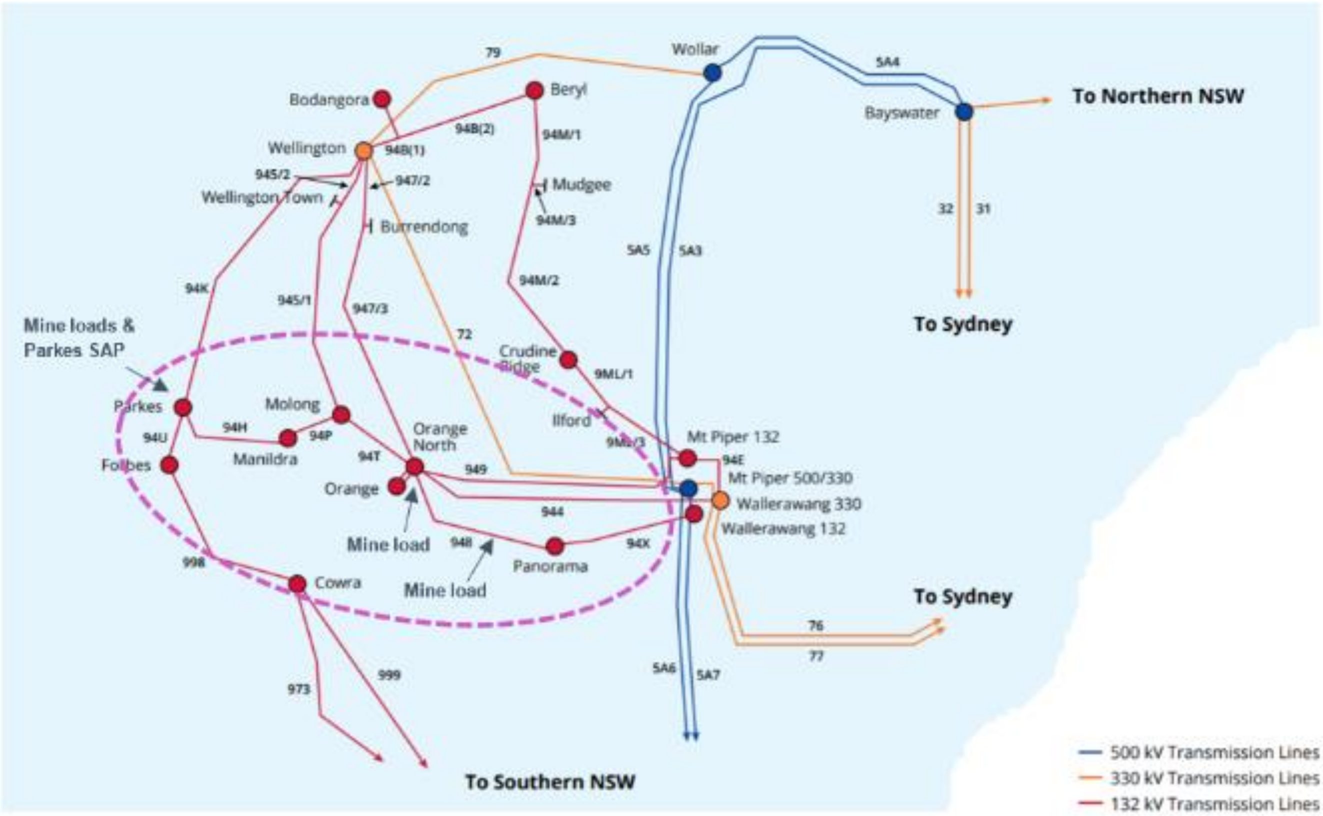
This section sets out a compliance checklist which demonstrates the compliance of this PADR with the requirements of clause 5.16.4 of the National Electricity Rules version 177.

Rules clause	Summary of requirements	Relevant section(s) in the **PADR**
5.16.4(k)	A RIT-T proponent must prepare a report (the assessment draft report), which must include:	-
	(1) a description of each credible option assessed;	4
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	3
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	6 & 7
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	5 & 6
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	6.5
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	7
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	7
	(8) the identification of the proposed preferred option;	7 & 8
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission.	4 & 8

Appendix B Overview of existing electricity supply arrangements in central west NSW

The current central west NSW electricity transmission network is shown in Figure B-1 below. The area relevant for this RIT-T is around Orange and Parkes and is circled below. The indicative location of key forecast electricity loads (which have been publicly announced) are also shown with arrows.

Figure B-1: Central west NSW transmission network



Electricity demand in central west NSW is forecast to increase significantly over the next ten years, primarily due to:

- expected demand growth in some existing large industrial loads (the names, locations and loads have been redacted due to confidentiality reasons);
- planned connections of new industrial loads, i.e. McPhillamy's mine[46] and Sunrise mine;[47] and
- the NSW government's Parkes Special Activation Precinct (SAP).[48]

Essential Energy forecasts increased load from some of the existing large industrial loads in the area going forward. The specific details regarding the mines, locations and load forecasts has not been provided for confidentiality reasons.

In addition, going forward, there are two further mines expected to connect in the region. Namely:

[46] https://www.regisresources.com.au/McPhillamys-Gold-Project/mcphillamys-gold-project.html
[47] https://www.cleanteq.com/sunrise-project/
[48] https://www.nsw.gov.au/snowy-hydro-legacy-fund/special-activation-precincts/parkes-special-activation-precinct

- the McPhillamy's gold mine, which is currently planned to connect within the next few years;[49] and
- CleanTeQ Sunrise Nickel-Cobalt-Scandium mine, which is also planned to connect within the next few years.[50]

These loads are located, or expected to be located, around Orange and Parkes in the central west region.

Specific load information for each of the expected mines has not been presented in this PADR due to this information being commercially sensitive.

There are a number of in-service and planned renewable generator connections in the central west region, particularly around Parkes. Table B-1 summarises these systems.

Table B-1: Current and planned renewable generation in the central west region

Generating System	Connection location	Capacity (MW)	Status
Parkes Solar Farm	Parkes 66 kV Busbar	50.5	In service
Manildra Solar Farm (EssE)	Manildra 11 kV Busbar	50	In service
Goonumbla Solar Farm	Parkes 66 kV Busbar	70	In service
Molong Solar Farm	Molong 66 kV Busbar	30	In service
Suntop Solar Farm	Line 94K (Wellington – Parkes tee Suntop Solar Farm)	150	Commissioning
Jemalong Solar Farm (EssE)	West Jemalong 66 kV Busbar	50	Committed
Flyers Creek Wind Farm (EssE)	Orange North 132 kV	138	Advanced*
Quorn Park Solar Farm (EssE)	Parkes 132 kV	80	Advanced*

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

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, commissioning, advanced and committed renewable generation in assessing the identified need for this RIT-T.

49 https://www.regisresources.com.au/McPhillamys-Gold-Project/mcphillamys-gold-project.html
50 https://www.cleanteq.com/sunrise-project/

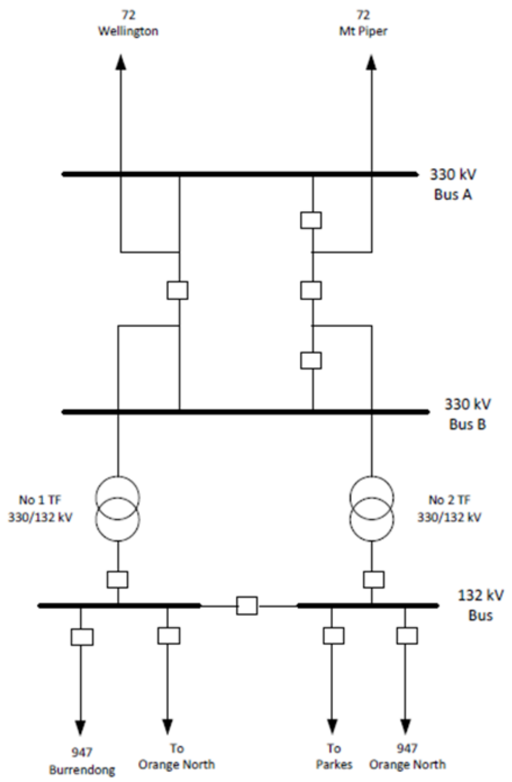
Appendix C Indicative line diagrams for each option

This appendix provides the line diagrams for each of the network elements of credible options considered in this PADR, as relevant. Existing elements are shown in black, while new elements are shown in red for all figures except Figure C-1 (since all elements are new and so have been presented as black for a neater presentation).

Option 1A/1B – New 330/132 kV substation at Orange ahead of a new Wellington to Parkes 132 kV line (if required)

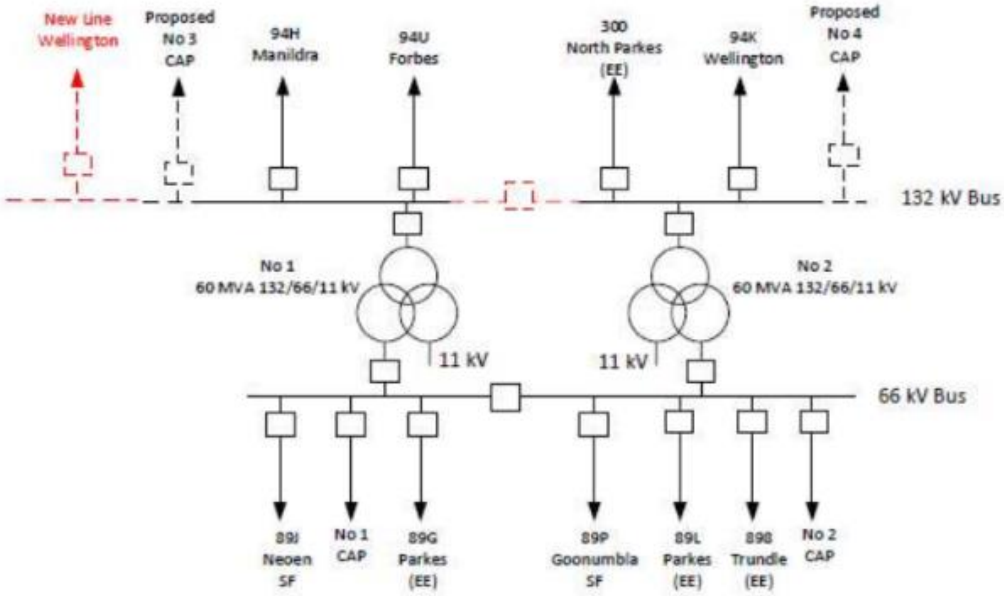
The indicative layout for the Orange 132/66 kV substation under Option 1A/1B is shown in Figure C-1 below.

Figure C-1: Indicative Orange new 330/132 kV substation layout under Option 1A/1B



The indicative ultimate layout for the Parkes 132/66 kV substation under Option 1A/1B is shown in Figure C-2 below.

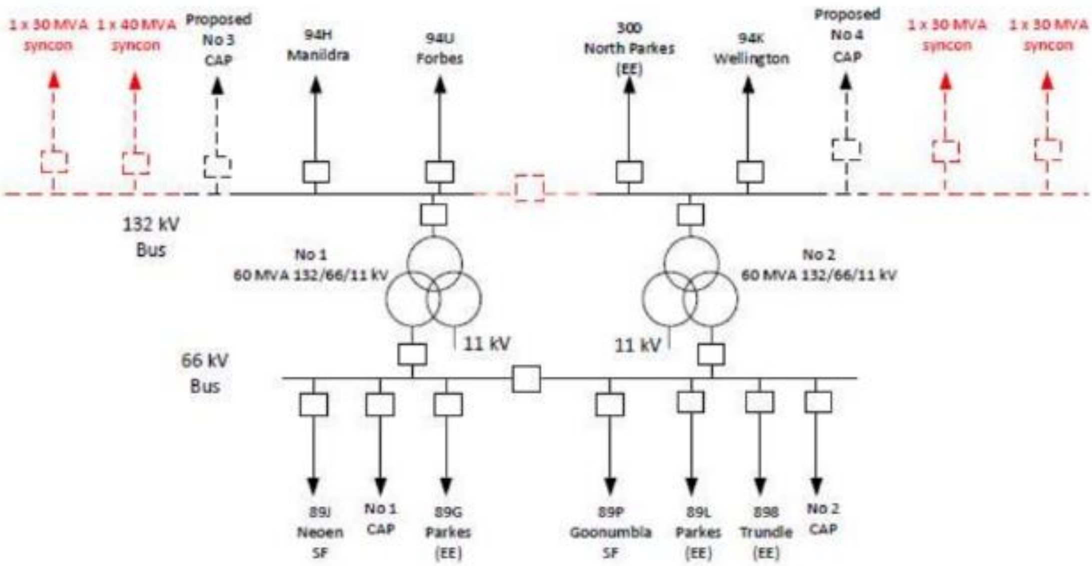
Figure C-2: Indicative Parkes 132/66 kV substation layout under Option 1A/1B



Option 1C – Reactive support at Parkes and a new 330/132 kV substation at Orange ahead of additional reactive support at Parkes (if required)

The indicative ultimate layout for the Parkes 132/66 kV substation under Option 1C is shown in Figure C-3 below.

Figure C-3: Indicative Parkes 132/66 kV substation layout under Option 1C

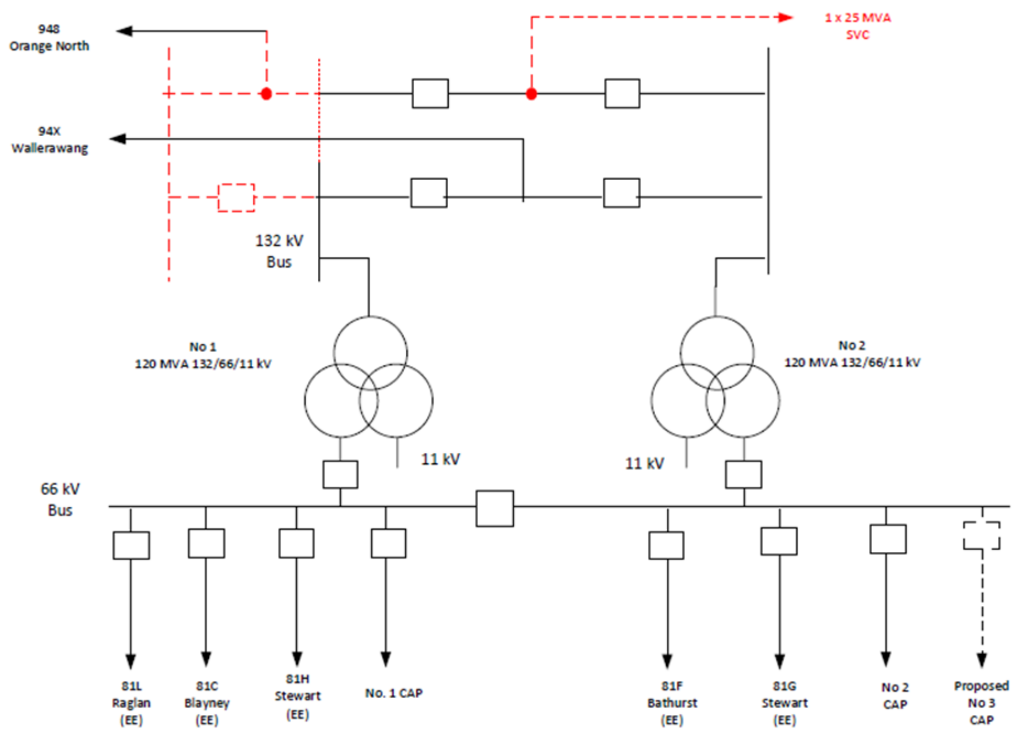


The indicative ultimate layout for the new Orange 330/132 kV substation under Option 1C is the same as that set out for Option 1A/1B in Figure C-1 above.

Option 3 – Reactive support at Panorama and Parkes ahead of a new 132 kV line from Wellington to Parkes (if required)

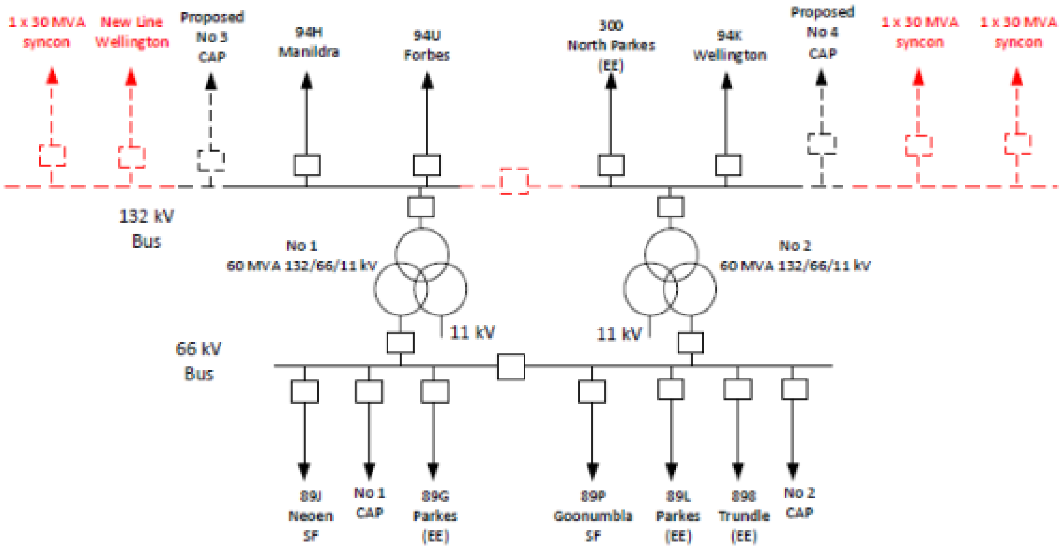
The indicative ultimate layout for the Panorama 132/66 kV substation under Option 3 is shown in Figure C-4 below.

Figure C-4: Indicative Panorama 132/66 kV substation layout under Option 3



The indicative ultimate layout for the Parkes 132/66 kV substation under Option 3 is shown in Figure C-5 below.

Figure C-5: Indicative Parkes 132/66 kV substation layout under Option 3



Option 4 – Reactive support at Panorama and Parkes ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)

The indicative ultimate layout for the Panorama 132/66 kV substation under Option 4 is the same as for Option 3 shown in Figure C-4 above.

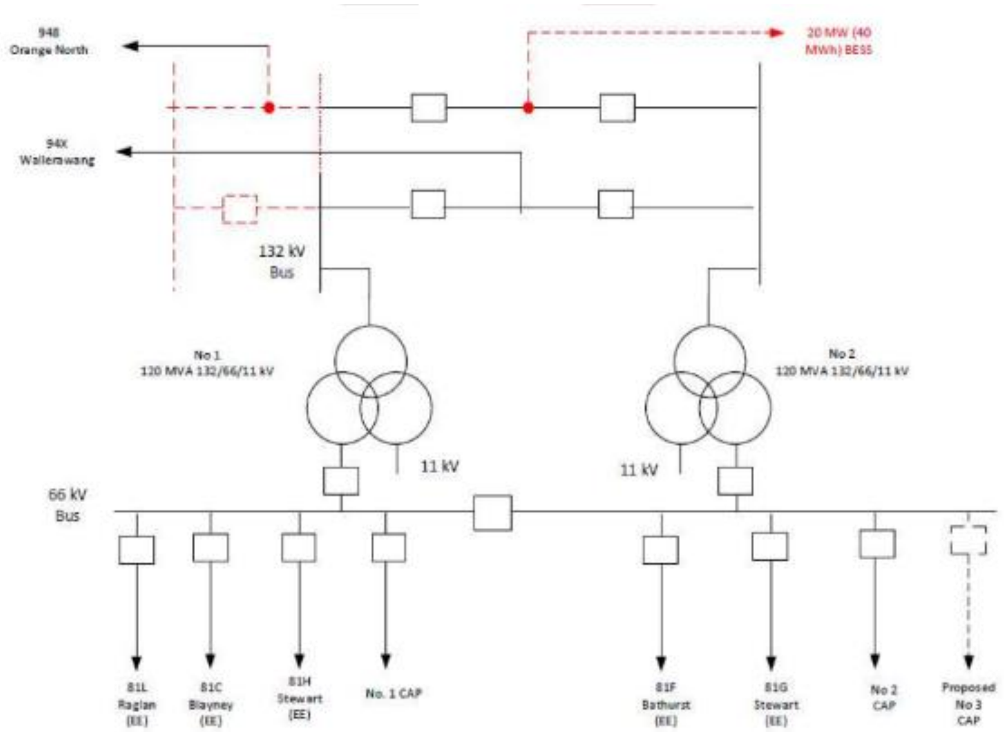
The indicative ultimate layout for the Parkes 132/66 kV substation under Option 4 is the same as for Option 1C shown in Figure C-3 above.

The indicative ultimate layout for the new Orange 330/132 kV substation under Option 4 is the same as for Option 1A/1B shown in Figure C-1 above.

Option 5 – Batteries at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 132 kV line from Wellington to Parkes (if required)

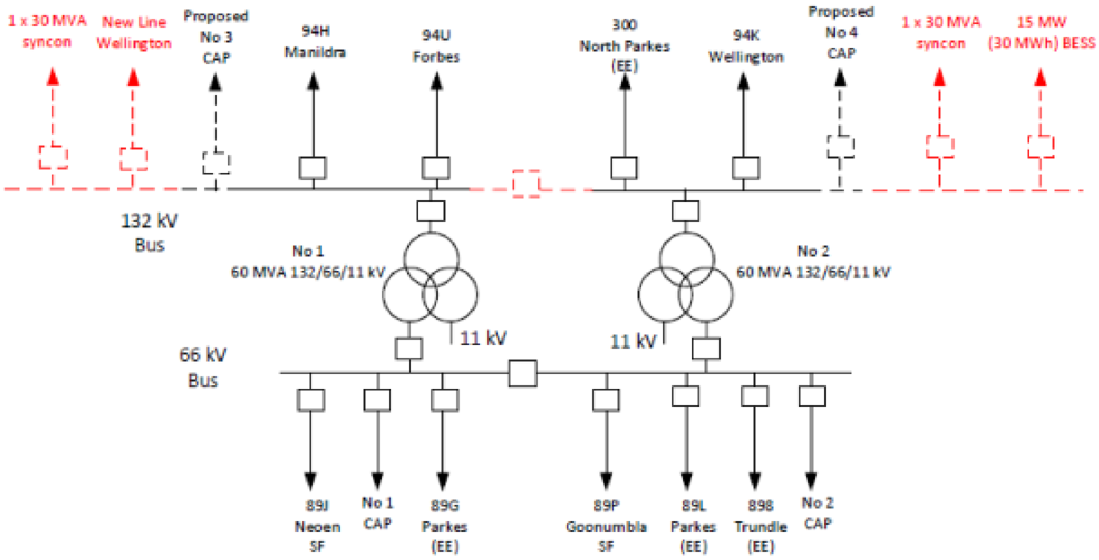
The indicative ultimate layout for the Panorama 132/66 kV substation under Option 5 is shown in Figure C-6 below.

Figure C-6: Indicative Panorama 132/66 kV substation layout under Option 5



The indicative ultimate layout for the Parkes 132/66 kV substation under Option 5 is shown in Figure C-7 below.

Figure C-7: Indicative Parkes 132/66 kV substation layout under Option 5

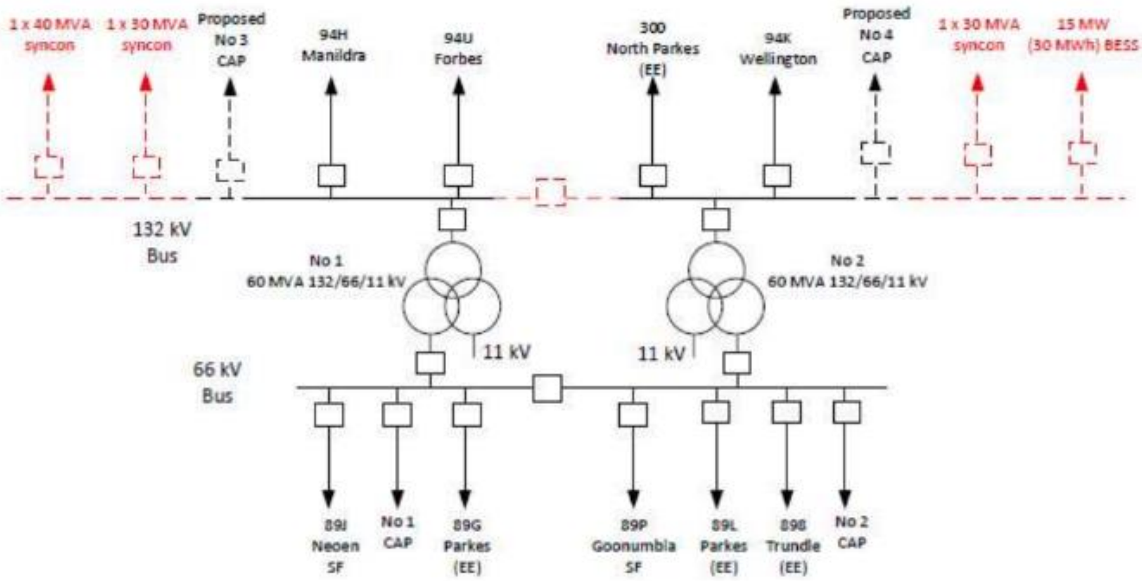


Option 6 – Batteries at Parkes and Panorama (plus reactive support at Parkes) ahead of a new 330/132 kV substation at Orange and additional reactive support at Parkes (if required)

The indicative ultimate layout for the Panorama 132/66 kV substation under Option 6 is shown in Figure C-6 above.

The indicative ultimate layout for the Parkes 132/66 kV substation under Option 6 is shown in Figure C-8 below.

Figure C-8: Indicative Parkes 132/66 kV substation layout under Option 6



An indicative ultimate layout for the new Orange 330/132 kV substation under Option 6 is shown in Figure C-1 above.

Appendix D Overview of the wholesale market modelling undertaken

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

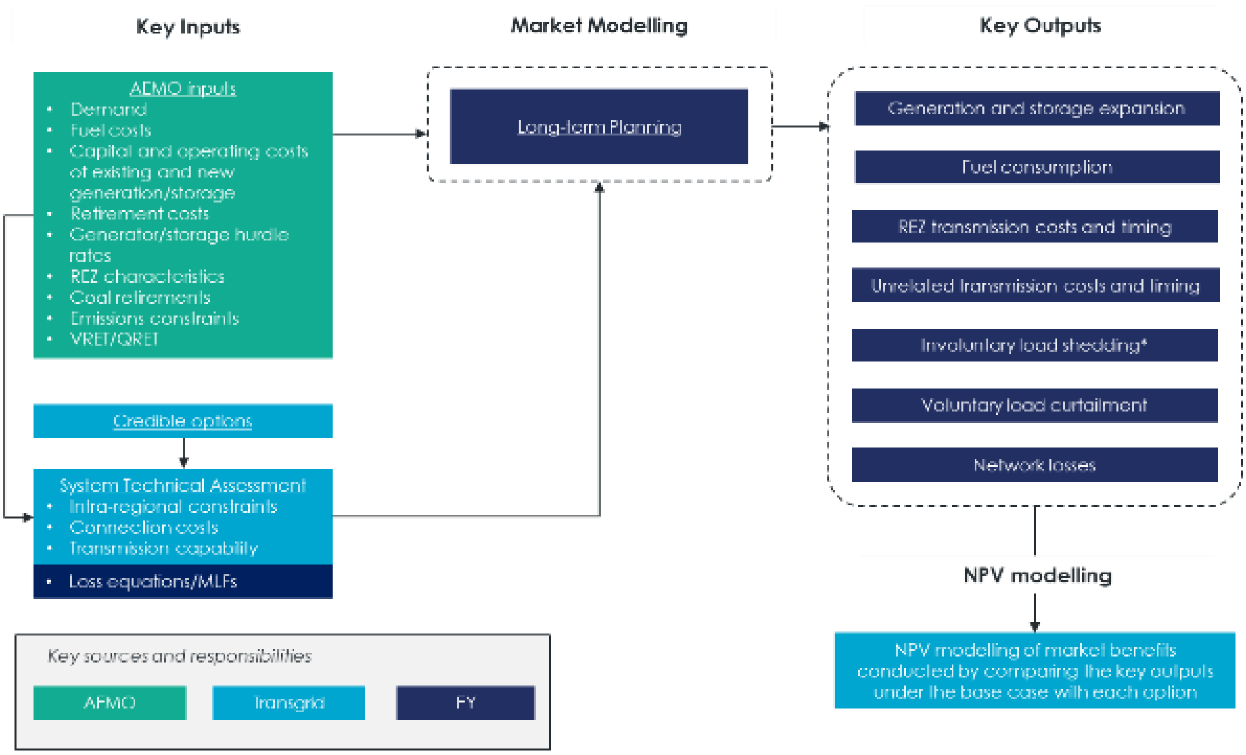
EY has applied a linear optimisation model and performed hourly, time-sequential, long-term modelling for the NEM to estimate categories of wholesale market benefits expected under the options that affect the wholesale market. Specifically, EY has undertaken market simulation exercise involving long-term investment planning, which identifies the optimum generation (including storage) and unrelated transmission infrastructure development schedule, while meeting reliability requirements, policy objectives, and technical generator and network performance limitations. This solves for the least-cost generation and transmission infrastructure development across the assessment period while meeting energy policies.

We have undertaken a detailed System Technical Assessment, which evaluates the power system behaviour and performance under each credible option and ensures market modelling outcomes are physically plausible, follow the operation of the NEM, and that the benefits of credible options align with the changes to the power system under each credible option. This assessment serves as an input to the wholesale market modelling exercises EY has undertaken (as outlined above).

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

Figure D-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 D-1: Overview of the market modelling process and methodologies



** As outlined in section 6.2, the avoided involuntary load shedding in the central west 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 PADR assessment.

Long-term Investment Planning

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

This exercise determines the least-cost development schedule for each credible option drawing on assumptions regarding demand, 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).[51]

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

[51] 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.

In addition, loss factors for each generator were applied. These were computed from an AC power flow programme interfaced with the Long-term Investment Planning model. The loss factors for each generation investment plan were computed on a five-year basis up to 2030-31 and fed back into the Long-term Investment Planning model to capture both the impact on bids and intra-zonal losses.

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

Summary of the key assumptions feeding into the wholesale market exercise

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

Table D-1: PADR modelled scenario key drivers input parameters

Key drivers input parameter	Progressive change scenario
Underlying consumption	ESOO 2021 (ISP 2022) - Progressive Change[52]
New entrant capital cost for wind, solar SAT, OCGT, CCGT, PSH, and large-scale batteries	2021 Input and Assumptions Workbook[53] - Progressive Change
Retirements of coal-fired power stations	2021 Input and Assumptions Workbook - Progressive Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030
Gas fuel cost	2021 Input and Assumptions Workbook - Progressive Change: Lewis Grey Advisory 2020, Central
Coal fuel cost	2021 Input and Assumptions Workbook - Progressive Change: WoodMackenzie, Central
Federal Large-scale Renewable Energy Target (LRET)	33 TWh per annum by 2020 to 2030 (including GreenPower and ACT scheme), accounting for contribution to LRET by Western Australia, Northern Territory and off grid locations
NEM carbon budget to achieve 2050 emissions levels	2021 Input and Assumptions Workbook - Progressive Change: 932 Mt CO_2-e 2030-31 to 2050-51
Victoria Renewable Energy Target (VRET)	40% renewable energy by 2025 and 50% renewable energy by 2030
Queensland Renewable Energy Target (QRET)	50% by 2030
Tasmanian Renewable Energy Target (TRET)	2021 Input and Assumptions Workbook: 200% Renewable generation by 2040
NSW Electricity Infrastructure Roadmap	2021 Input and Assumptions Workbook: 12 GW NSW Roadmap, with 3 GW in the Central West Orana REZ, modelled as generation constraint per the 2022 ISP 2 GW Pumped Storage Hydro by 2029-30.

52 AEMO, *National Electricity and Gas Forecasting*, http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed 17 January 2022.
53 AEMO, *2021 Input and Assumptions Workbook*, https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios, Accessed 17 January 2022.

Key drivers input parameter	Progressive change scenario
South Australia Energy Transformation RIT-T	Draft 2022 Integrated System Plan[54] – Progressive Change: EnergyConnect is commissioned by July 2025.[55]
Western Victoria Renewable Integration RIT-T	Draft 2022 Integrated System Plan – Progressive Change: the Western Victoria upgrade commissioned by July 2025
HumeLink	Draft 2022 Integrated System Plan – Progressive Change: HumeLink commissioned by July 2035
Marinus Link	Draft 2022 Integrated System Plan – Progressive Change:1st cable commissioned by July 2029 and 2nd cable by July 2031
Victoria to NSW Interconnector Upgrade	Draft 2022 Integrated System Plan – Progressive Change: VNI Minor commissioned by December 2022.
NSW to QLD Interconnector Upgrade (QNI Minor)	Draft 2022 Integrated System Plan – Progressive Change: QNI minor commissioned by July 2022
QNI Connect	Draft 2022 Integrated System Plan – Progressive Change: QNI Connect commissioned by July 2036
VNI West	Draft 2022 Integrated System Plan – Progressive Change: VNI West commissioned by July 2038.
Victorian SIPS[56]	Draft 2022 Integrated System Plan – Progressive Change: 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 Integrated System Plan – Progressive Change: New England REZ Transmission Link commissioned by July 2027 and New England REZ Extension commissioned by July 2038
Snowy 2.0	Draft 2022 Integrated System Plan –Snowy 2.0 is commissioned by December 2026

[54] AEMO, *draft 2022 Integrated System Plan*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation. Accessed 17 January 2022.

[55] ElectraNet, 13 February 2019. *SA Energy Transformation RIT-T: Project Assessment Conclusions Report*. Available at: https://www.electranet.com.au/wp-content/uploads/projects/2016/11/SA-Energy-Transformation-PACR.pdf. Accessed 28 June 2021. There are options for commissioning between 2022 and 2024. Limits also from this document.

[56] Victoria Government, Victorian Big Battery, Available at: https://www.energy.vic.gov.au/renewable-energy/the-victorian-big-battery/the-victorian-big-battery-q-and-a, Accessed 1 July 2021.