Transgrid

People. Power. Possibilities.

Complying with reactive margin requirements at Beryl

RIT-T Project Assessment Draft Report

Region: Central West NSW

Date of issue: 17 February 2026

Disclaimer

This suite of documents comprises Transgrid's application of the Regulatory Investment Test for Transmission (RIT-T) which has been prepared and made available solely for information purposes. It is made available on the understanding that Transgrid and/or its employees, agents and consultants are not engaged in rendering professional advice. Nothing in these documents is a recommendation in respect of any possible investment.

The information in these documents reflect the forecasts, proposals and opinions adopted by Transgrid at the time of publication, other than where otherwise specifically stated. Those forecasts, proposals and opinions may change at any time without warning. Anyone considering information provided in these documents, at any date, should independently seek the latest forecasts, proposals and opinions.

These documents include information obtained from the Australian Energy Market Operator (AEMO) and other sources. That information has been adopted in good faith without further enquiry or verification. The information in these documents should be read in the context of the Electricity Statement of Opportunities, the Integrated System Plan published by AEMO and other relevant regulatory consultation documents. It does not purport to contain all of the information that AEMO, a prospective investor, Registered Participant or potential participant in the National Electricity Market (NEM), or any other person may require for making decisions. In preparing these documents it is not possible, nor is it intended, for Transgrid to have regard to the investment objectives, financial situation and particular needs of each person or organisation which reads or uses this document. In all cases, anyone proposing to rely on or use the information in this document should:

1. Independently verify and check the currency, accuracy, completeness, reliability and suitability of that information
2. Independently verify and check the currency, accuracy, completeness, reliability and suitability of reports relied on by Transgrid in preparing these documents
3. Obtain independent and specific advice from appropriate experts or other sources.

Accordingly, Transgrid makes no representations or warranty as to the currency, accuracy, reliability, completeness or suitability for particular purposes of the information in this suite of documents.

Persons reading or utilising this suite of RIT-T-related documents acknowledge and accept that Transgrid and/or its employees, agents and consultants have no liability for any direct, indirect, special, incidental or consequential damage (including liability to any person by reason of negligence or negligent misstatement) for any damage resulting from, arising out of or in connection with, reliance upon statements, opinions, information or matter (expressed or implied) arising out of, contained in or derived from, or for any omissions from the information in this document, except insofar as liability under any New South Wales and Commonwealth statute cannot be excluded.

Privacy notice

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.

Under the National Electricity Law, there are circumstances where Transgrid may be compelled to provide information to the Australian Energy Regulator (AER). Transgrid will advise you should this occur.

Transgrid’s Privacy Policy sets out the approach to managing your personal information. In particular, it explains how you may seek to access or correct the personal information held about you, how to make a complaint about a breach of our obligations under the Privacy Act, and how Transgrid will deal with complaints. You can access the Privacy Policy here (https://www.transgrid.com.au/Pages/Privacy.aspx).

Executive summary

The Transgrid Beryl 132/66 kV Bulk Supply Point (BSP) currently supplies the Essential Energy distribution network, with end customers comprising a mixture of agricultural, residential and mining customers.

As set out in our revenue proposal for the current (2023-28) regulatory control period,[1] and most recent Transmission Annual Planning Report (TAPR),[2] we have identified reactive margin shortfall (and voltage) issues in the Beryl area in light of current and projected demand in the downstream Essential Energy distribution network.

We are therefore applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining reliable supply to the Beryl area of Central West New South Wales (NSW). This Project Assessment Draft Report (PADR) represents the second step in the application of the RIT-T and follows the Project Specification Consultation Report (PSCR) and Expression of Interest (EOI) published on 15 November 2024.

Identified need: maintaining compliance with the NER reactive margin requirements

Schedule 5.1.8 of the National Electricity Rules (NER) require Transgrid to operate its network to satisfy reactive margin requirements.

If action is not taken, our planning studies show that the current network will risk not being capable of supplying load in the area in the coming years without breaching the NER reactive margin requirements. This has the potential to lead to significant unserved energy to customers in the area due to interruption of supply under (N-1) contingency conditions.

We are therefore undertaking this RIT-T to assess the options available for managing reactive margin requirements to avoid these consequences and continuing to maintain compliance with the relevant NER standards. 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.

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

We received two submissions from non-network proponents following the PSCR

We received two submissions from non-network proponents to the EOI. The proposed non-network solutions were:

- a currently in-service generator in the region which currently provides automatic reactive support through its filters, who submitted a proposal to leave its inverters on even in periods where it is not generating to provide additional support; and
- a proposed BESS which is able to provide reactive power.

1 Transgrid, *Augex Overview Paper*, 2023-28 Revenue Proposal, 31 January 2022, p. 32.
2 Transgrid, *Transmission Annual Planning Report 2025*, p. 59.

The generator is estimated to provide approximately 15 MVAr of reactive power support automatically through its filters. We have factored this into the assessment for the base case in this PADR.

We have also been engaging with the generator proponent on their ability to provide additional support beyond that automatically provided, but we are unable to verify that this is technically feasible. We also consider that, even if the proposal is found to be technically feasible, it would not be sufficient to provide the required reactive support by itself. We have therefore not included this proposal as an option in this PADR.

The proposed BESS is estimated to provide approximately 40 MVAr of reactive power support automatically via its access standard, which would be sufficient to meet the identified need. We have assessed this proposal as one of the options in this PADR (Option 3).

While the proponent expects the BESS to be in-service by October 2028, Transgrid's assessment at this point in time based on information provided by the proponent is that the BESS is not yet sufficiently advanced to be considered 'committed' or 'anticipated' by reference to the criteria set out under the RIT-T. However, we have investigated a sensitivity where the BESS is assumed to meet these criteria (and ultimately proceed irrespective of this RIT-T), in order to assess whether the RIT-T outcome would be affected if the BESS does meet the criteria to be 'anticipated' or 'committed' in the near future. We will continue to engage with the proponent to understand the progression of this proposal, and the degree of certainty around the in-service date.

Three credible options have been assessed, across three scenarios

The credible options considered in this PADR assessment have been refined since the PSCR to reflect submissions to the EOI for non-network solutions issued alongside the PSCR and additional analysis by Transgrid.

Table E-1: Summary of the credible options considered at this stage, $2025/26

Option	Description	Capital cost ($m)	Commissioning
1	Install a 60 MVA synchronous condenser (syncon) at Beryl	52.4	2029/30
2	Install a static VAR compensator (SVC) of +50 MVAr to -10 MVAr at Beryl	44.1	2029/30
3	A 100 MW / 200 MWh non-network BESS	93.2[3]	October 2028

None of the credible options listed above are expected to have a material inter-regional impact.

While the option of constructing and operating a network BESS at Beryl was identified as a potential credible option in the PSCR, Transgrid considers the non-network option proponent is better placed than Transgrid to deliver a BESS. The non-network option proponent is further advanced in its planning processes and may meet the RIT-T criteria for an 'anticipated' or 'committed' project ahead of the PACR.

The credible options have been assessed under three scenarios as part of this PADR assessment. The only market benefit considered to be material is changes in involuntary load shedding and so, as a result, the three PADR scenarios differ only through their assumed demand forecasts.

3 Since the BESS is not yet considered 'committed' or 'anticipated' under the RIT-T, its full capital (and operating) cost are included in the PADR assessment, consistent with the RIT-T framework.

Table E.2: Summary of the three scenarios

Variable/scenario	Central demand scenario	Low demand scenario	High demand scenario
Scenario weighting	1/3	1/3	1/3
Demand growth	Central forecast (from section 5.1)	Low forecast (from section 5.1)	High forecast (from section 5.1)
Discount rate	7%	7%	7%
Value of Customer Reliability (VCR) ($/kWh)	17.37	17.37	17.37
Network capital costs	Base estimate	Base estimate	Base estimate

Option 2 has the greatest estimated net market benefits

Option 2 is found to be the top-ranked option in all scenarios. On a weighted basis,[4] Option 2 delivers net market benefits that are approximately $5.3 million and $55.5 million higher, in present value terms, than Option 1 and Option 3, respectively.

Table E.3: Present value of the net market benefits for each option ($m 2025/26) – ranking shown in parentheses

Option/scenario	Central demand	Low demand	High demand	Weighted
Scenario weighting	1/3	1/3	1/3	
Option 1 – syncon	-26.8 (2)	-34.4 (2)	-13.8 (2)	-25.0 (2)
Option 2 – SVC	**-21.5** **(1)**	**-29.1** **(1)**	**-8.5** **(1)**	**-19.7** **(1)**
Option 3 – BESS	-77.3 (3)	-85.9 (3)	-62.3 (3)	-75.2 (3)

Given this RIT-T is a reliability corrective action, the preferred option is permitted to have negative estimated net market benefits.[5]

The finding that Option 2 is the top-ranked option is found to be robust to a range of sensitivity tests, including different assumed network capital costs, BESS capital costs, commercial discount rates and VCR values. We also do not find any realistic boundary values for these variables that would change this result.

While the wholesale market benefits of the BESS under Option 3 have not been estimated at this stage, we note that, if included, they would add to the expected net market benefits of Option 3. We intend to consider the materiality of these expected benefits further as part of the PACR, and whether the inclusion of market benefits would impact the option rankings.

Under the sensitivity where the BESS is assumed to meet the criteria for ‘anticipated’ or ‘committed’ (and ultimately proceed irrespective of this RIT-T), Option 3 becomes preferred over the other two options. Under

[4] Given the results show the same option is preferred in all three scenarios, the weights applied to each scenario are not material at this draft stage. We have therefore adopted a proportionate approach by weighting the three scenarios equally and have not sought to develop more specific weights.

[5] As stipulated in clause 5.15A.1 of the NER.

this sensitivity, the BESS in Option 3 would resolve the identified need under the base case and there would be no need to undertake any network option.

Option 2 is the preferred option at this draft stage

Option 2 is found to be the preferred option at this draft stage for managing reactive margin requirements and continuing to maintain compliance with the relevant NER standards. Option 2 involves the construction of a new SVC at Beryl with a range of +50 MVAr to -10 MVAr.

The scope of works for this option is expected to be carried out between 2025/26 and 2029/30, with the expected commissioning date for this option being 2029/30. The estimated capital cost of this option is approximately $44.1 million.

However, if the proponent of the BESS is able to provide Transgrid with credible evidence that it meets the definition of either 'anticipated' or 'committed' (by reference to the criteria set out under the RIT-T), and sufficient assurance that the reactive support will be in-service by the assumed October 2028 date, then Option 3 may become the preferred option for this RIT-T.

We will continue to liaise with the proponent of this solution and ensure that the latest information available is reflected in the PACR analysis. In particular, we will be seeking from the BESS proponent further credible evidence regarding:

- the progress of the BESS against the criteria for 'committed' status under the RIT-T; and
- assuming it does not meet this status, the expected costs of the project in order to base the PACR assessment on more specific cost estimates (i.e., as opposed to the generic, non-locational ISP costs used in this PADR).

Overall, given this is a reliability corrective action RIT-T, Transgrid requires a high degree of certainty that the BESS will be commissioned on-time for Option 3 to ultimately be preferred. We would therefore require the proponent to provide sufficient assurance regarding the BESS development timeframes, irrespective of whether it is considered 'anticipated' or 'committed' under the RIT-T, for it to be considered as the ultimately preferred option.

Submissions and next steps

We welcome written submissions on materials contained in this PADR. Submissions are due on 1 April 2026.[6]

Submissions to this PADR should be emailed to our Regulation team via regulatory.consultations@transgrid.com.au.[7] In the subject field, please reference 'Complying with reactive margin requirements at Beryl PADR'.

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.

6 Consultation period is for 6 weeks.

7 We are bound by the *Privacy Act 1988 (Cth)*. In making submissions in response to this consultation process, we 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. See Privacy Notice within the Disclaimer for more details.

Subject to what is proposed in submissions to this PADR, we anticipate publication of a PACR by October 2026.

Contents

Disclaimer **1**

Privacy notice 1

Executive summary **3**

1. Introduction **10**

1.1. Purpose of this report 11

1.2. Submissions and next steps 11

2. The identified need **13**

2.1. Background 13

2.2. Description of the identified need 16

2.3. Assumptions underpinning the identified need 17

2.3.1. General load at the Beryl BSP 17

2.3.2. Renewable generation and energy storage in the region 18

2.3.3. Reactive power margin shortfalls if action is not taken 19

3. Consultation on the PSCR **20**

4. Credible options that meet the identified need **21**

4.1. Base case 21

4.2. Option 1 – 60 MVA synchronous condenser 22

4.3. Option 2 – SVC of +50 MVAr to -10 MVAr 23

4.4. Option 3 – 100 MW / 200 MWh non-network BESS in the Beryl area 24

4.5. Options considered but not progressed 25

5. Materiality of market benefits **26**

5.1. Changes in involuntary load curtailment are material for this RIT-T assessment 26

5.2. Wholesale market benefits have not been assessed in the PADR but will be considered further for the BESS option 26

5.3. No other classes of market benefits are material 27

6. Overview of the assessment approach **28**

6.1. Assessment period and discount rate 28

6.2. Approach to estimating option costs 28

6.3. Value of customer reliability 29

6.4. The options have been assessed against three reasonable scenarios 30

7. Assessment of credible options **31**

7.1. Estimated gross market benefits 31
7.2. Estimated costs 31
7.3. Estimated net market benefits 32
7.4. Sensitivity testing 32
7.4.1. General sensitivity testing of the overall estimated net benefits 32
7.4.2. The proposed BESS becoming ‘anticipated’ or ‘committed’ 34

8. Draft conclusion 36

Appendix A Compliance checklist 37

1. Introduction

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining reliable supply to the Beryl area of Central West New South Wales (NSW) in light of current and projected demand in the Essential Energy distribution network. This Project Assessment Draft Report (PADR) represents the second step in the application of the RIT-T and follows the Project Specification Consultation Report (PSCR) and Expression of Interest (EOI) published on 15 November 2024.

As set out in our revenue proposal for the current (2023-28) regulatory control period,[8] and most recent (2025) Transmission Annual Planning Report (TAPR),[9] we have identified reactive margin shortfall issues (as well as voltage constraints) in the Beryl area given current and projected demand in the downstream Essential Energy distribution network. The Transgrid Beryl 132/66 kV Bulk Supply Point (BSP) currently supplies the Essential Energy distribution network, with end customers comprising a mixture of agricultural, residential and mining customers.

While load at the Beryl BSP has grown in recent years, with actual demand for 2025 winter peak of 76 MW and forecast summer 2025/26 peak of 80 MW, based on updated 2026 demand forecasts from Essential Energy, it is now forecast to remain relatively flat going forward. During a contingent outage of Line 94B (between Beryl and Wellington) the current network capacity would likely need to be limited to 68 MW to alleviate reactive margin issues and avoid voltage collapse in the part of the Essential Energy network supplied from the Beryl BSP.[10]

The National Electricity Rules (NER) require Transgrid to operate its network to satisfy reactive margin requirements. Specifically, under NER Schedule 5.1.8, Transgrid is required to ensure that the reactive power margin at any connection point is not less than 1% of the maximum fault level (in MVA) at the connection point.

If action is not taken, our planning studies show that the current network will risk not being capable of supplying load in the area in the coming years without breaching the NER reactive margin requirements. This has the potential to lead to significant unserved energy to customers in the area due to interruption of supply under (N-1) contingency conditions.

While no significant unserved energy has occurred to-date due to contingent outages having not occurred during these peak periods, our power system studies have identified continuing reactive margin shortfall issues in the Beryl area, if action is not taken, particularly when the renewable generation in the area is not being dispatched. To manage the risk before a solution can be put in place following this RIT-T, we have operational arrangements for shedding load if required.[11]

This RIT-T is assessing the options available for managing reactive margin requirements to avoid these consequences and continuing to maintain compliance with the relevant NER standards.

The Australian Energy Regulator (AER), and its consultant, considered as part of our latest regulatory determination that the need for this project was sensitive to assumed demand growth and that network expenditure could potentially be deferred a year or two if load growth is lower than expected (or if a non-

8 Transgrid, *Augex Overview Paper*, 2023-28 Revenue Proposal, 31 January 2022, p. 32.
9 Transgrid, *Transmission Annual Planning Report 2025*, p. 59.
10 This has been calculated based on the amount of pre-contingent load shedding required under normal system conditions to alleviate reactive margin issues following a contingent outage of Line 94B
11 Transgrid will continue the current practice of shedding load to manage the contingency based on Transgrid's Grid Operating Manual OM 620

network solution is identified).[12] We note that, while both summer and winter demand forecast for Beryl (provided by Essential Energy), have decreased since submitting our revised regulatory proposal, and our latest studies show that the reactive margin shortfall is still forecast to occur at demand levels significantly lower than the most recent 50% probability of exceedance (POE) forecasts.

1.1. Purpose of this report

The purpose of this PADR[13] is to:

- confirm the identified need for the investment, and describe the assumptions underlying this need;
- describe the options being assessed under this RIT-T, including those proposed by non-network proponents in response to the PSCR and EOI;
- set out the basis on which the costs of the credible option(s) have been estimated at this stage of the RIT-T process;
- summarise our approach to modelling the net market benefit for the credible options assessed, and present the results of this analysis;
- describe the key drivers of the NPV results, as well as the assessment that has been undertaken to ensure the robustness of the conclusion; and
- provide details of the overall proposed preferred option at this stage of the process to meet the identified need.

Overall, this report provides transparency into the planning considerations for investment options to manage reactive margin shortfalls at Beryl. 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.

1.2. Submissions and next steps

We welcome written submissions on materials contained in this PADR. Submissions are due on 1 April 2026.[14]

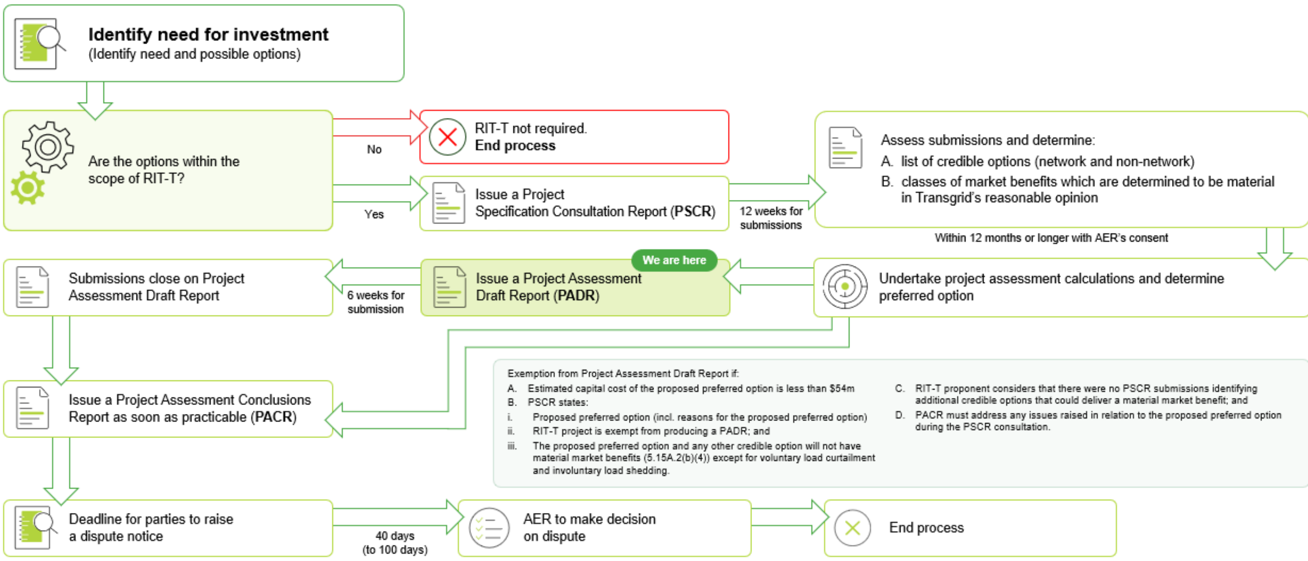
Submissions to this PADR should be emailed to our Regulation team via regulatory.consultations@transgrid.com.au.[15] In the subject field, please reference 'Complying with reactive margin requirements at Beryl PADR'.

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.

[12] AER, *Draft Decision - Transgrid Transmission Determination 2023 to 2028 (1 July 2023 to 30 June 2028) | Attachment 5 Capital expenditure,* September 2022, p.31.
[13] See Appendix A for the NER requirements.
[14] Consultation period is for 6 weeks.
[15] We are bound by the *Privacy Act 1988 (Cth)*. In making submissions in response to this consultation process, we 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. See Privacy Notice within the Disclaimer for more details.

Subject to what is proposed in submissions to this PADR, we anticipate publication of a PACR by October 2026.

Figure 1.1 This PADR is the second stage of the RIT-T Process[16]



[16] Australian Energy Market Commission. "*Replacement expenditure planning arrangements, Rule determination*". Sydney: AEMC, 18 July 2017.

2. The identified need

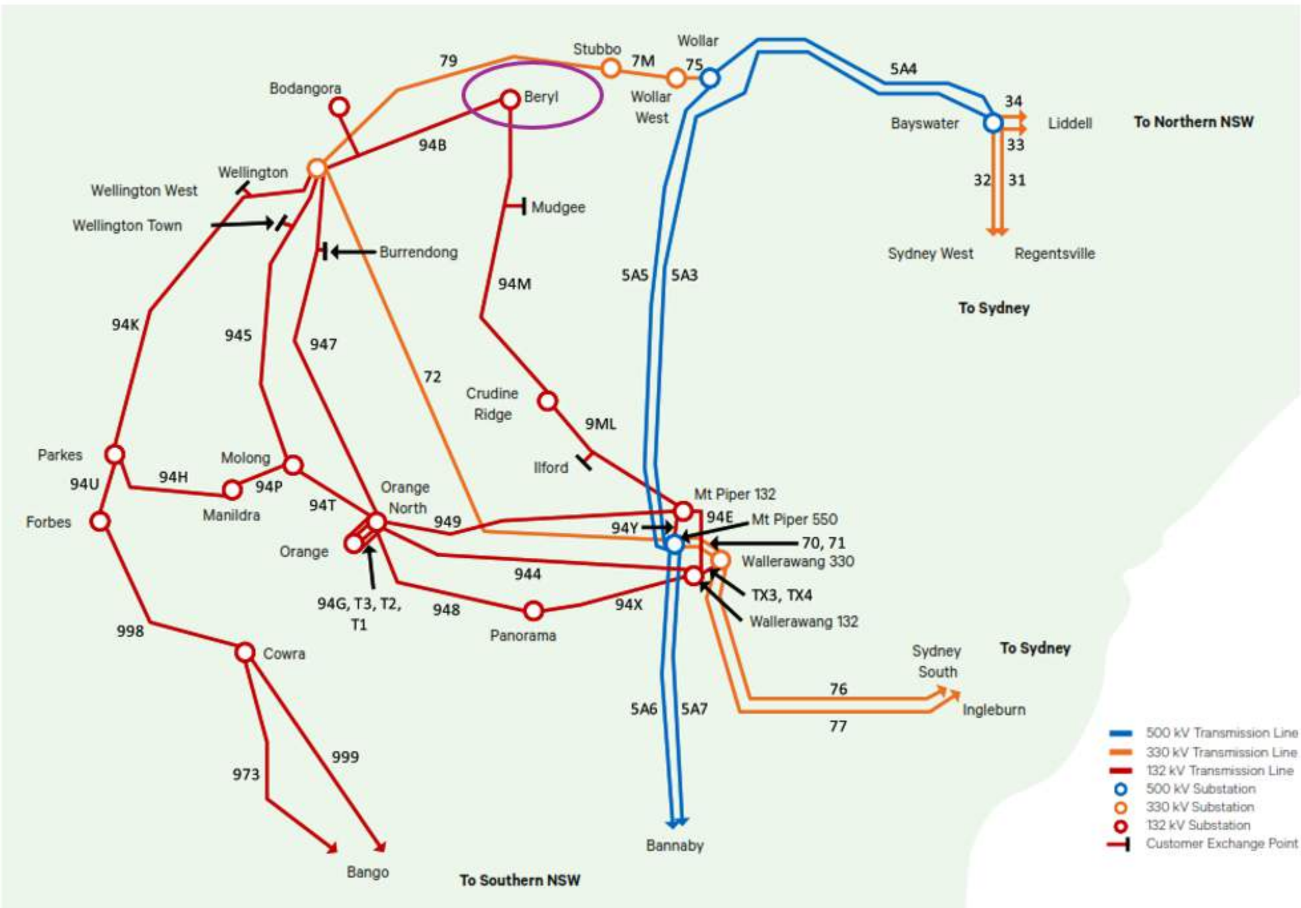
This section outlines the identified need for this RIT-T, as well as the assumptions and data underpinning it. It first sets out relevant background information in relation to the current network and the forecast constraints.

2.1. Background

The Beryl BSP is located in the Central West region of NSW and currently supplies the Essential Energy distribution network in the area. End customers served at the distribution level are a mixture of agricultural, residential and mining customers.

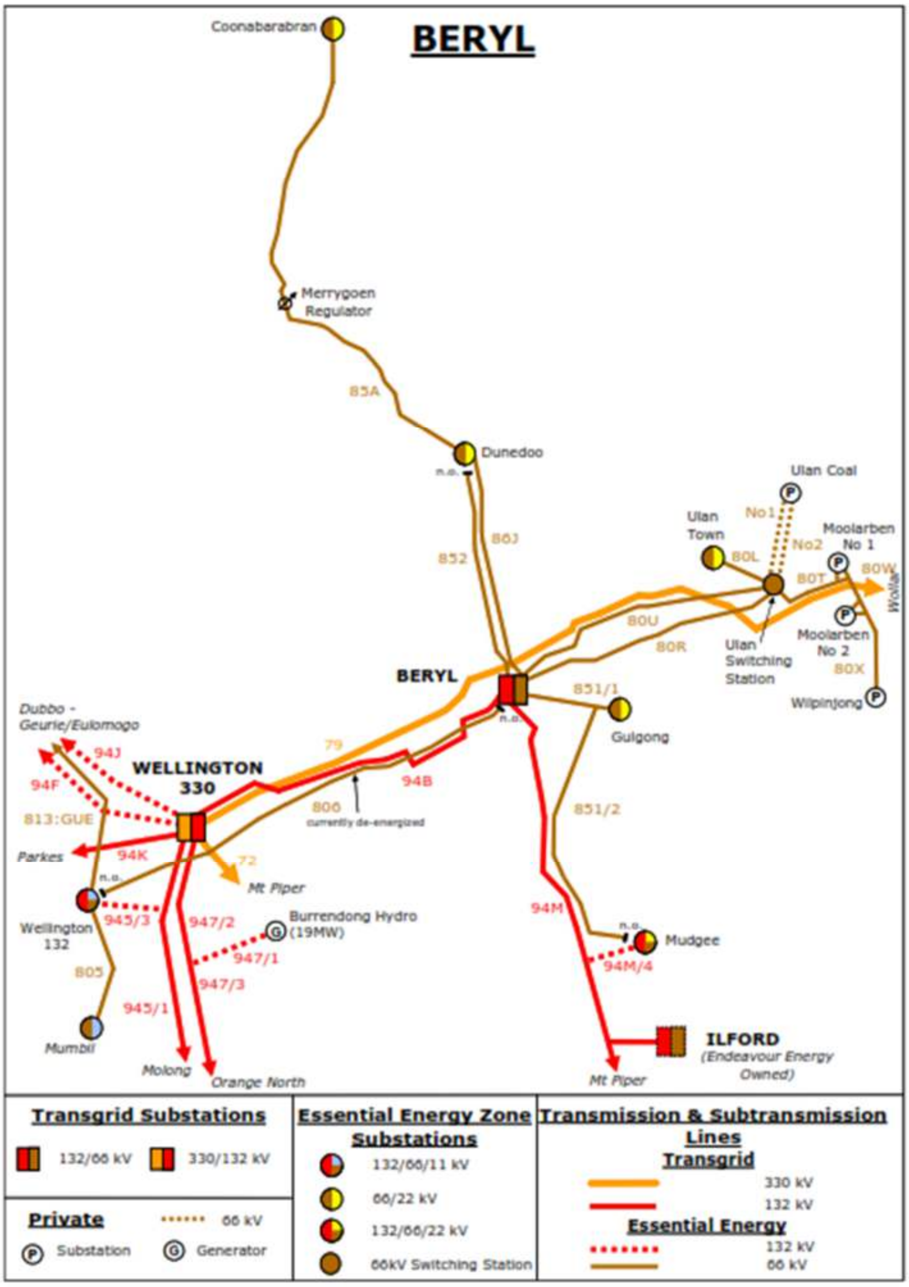
A map showing the location of the Beryl BSP (top left and circled in purple), and the surrounding Central West NSW transmission network, is presented below in Figure 2.1.

Figure 2.1 Central West NSW transmission network



A sub-transmission single line diagram for Beryl, showing both the distribution and transmission networks, is shown in Figure 2.2 below.

Figure 2.2 Single line diagram showing the distribution and transmission networks in Beryl



During 2023, we completed a RIT-T to maintain the safe and reliable operation of Beryl substation (Beryl BSP) and the broader transmission network in NSW, by addressing the risk of failure of certain high voltage and secondary systems assets at the substation.[17] The identified need for that RIT-T is separate to the

[17] https://www.transgrid.com.au/media/015jglnx/transgrid-pacr_maintaining-safe-and-reliable-operation-of-beryl-substation.pdf

identified need for this current RIT-T and the preferred option identified through that process was a targeted asset replacement (which is currently being undertaken, with completion scheduled for 2026/27).

Observed actual maximum demand for the Beryl BSP over the most recent summer and winter periods was 76 MW for both periods. The majority of this load is attributable to mining load in the region (i.e., the three mines shown centre-right of Figure 2.2 above).

Beryl BSP load is now forecast to remain relatively flat going forward. Specifically, load growth for the Beryl BSP, which is informed by the individual zone substation forecasts provided by Essential Energy, is currently forecast to grow at approximately 0.5 per cent/year over the next 10 years.[18]

We estimate that at current demand levels, during a contingent outage of Line 94B (Beryl-Wellington), network capacity would likely need to be limited to 68 MW in order to alleviate reactive margin issues and avoid complete voltage collapse in the Essential Energy network.[19]

The observed maximum demands during the most recent summer and winter periods highlight that there is a real risk of supply interruptions and substantial unserved energy to end customers if a contingency occurs, particularly when the renewable generation in the area is not being dispatched. No significant unserved energy has occurred to-date, due to contingent outages having not occurred during these peak periods. Further, to manage the risk before a solution can be put in place following this RIT-T, we have operational arrangements in place for shedding load, if required.[20]

The Beryl BSP is expected to play a central role in the transition to a low-carbon electricity future for NSW, due to its location relative to high-quality renewable resources. Three renewable generators are already in-service in the region – namely:

- Beryl Solar Farm – an 87 MW single-axis tracking solar farm commissioned in 2019 and located west of Gulgong;
- Bodangora Wind Farm – a 125 MW wind farm commissioned in 2019 near Wellington; and
- Crudine Ridge Wind Farm – a 138 MW wind farm commissioned in 2022 and located south of Mudgee.

In addition, there are several proposed generation and storage developments in the Beryl area, including:

- Dunedoo Solar Farm – a anticipated 55 MW solar farm near the township of Dunedoo that received development consent from the Department of Planning, Industry and Environment in 2022 and is expected to connect to Essential Energy's Dunedoo Zone Substation (but is yet to start construction);[21]
- Bellambi Heights Battery Energy Storage System (BESS) – a 354 MW BESS to be built near Gulgong (and connected to the 330 kV network) with construction targeted to start in 2026;[22] and

[18] This has been calculated for summer load. Winter load growth is forecast to be near zero over this period.
[19] This has been calculated based on the amount of pre-contingent load shedding required under normal system conditions to alleviate reactive margin issues following a contingent outage of Line 94B
[20] Transgrid will continue the current practice of shedding load to manage the contingency based on Transgrid's Grid Operating Manual OM 620
[21] NSW Government Department of Planning, Industry and Environment, *Development Consent* | *Dunedoo Solar Farm*, 2 September 2021.
[22] https://www.venaenergy.com.au/all_projects/bellambi-heights-bess/

- Beryl BESS – a 100MW/200MWh BESS near Gulgong proposed to be connected to Beryl substation, with via a direct 132 kV connection.[23]

The Beryl BESS is listed as 'publicly announced' in the latest (January 2026) AEMO 'NEM generation Information' file and is not currently considered by Transgrid to meet the RIT-T criteria for 'committed' or 'anticipated'.

While Dunedoo Solar Farm was updated to be considered 'anticipated' by AEMO in January 2026, we consider that it has limited impact on the identified need since there is no BESS connected and its generation during peak demand periods will be low. Due to it being considered 'proposed' in the previous (October 2025) AEMO 'NEM generation Information' file, we have not modelled it directly as part of this PADR (but we may review this if it is considered material in the PACR).

Since the PSCR was published, the Bellambi Heights BESS is now considered 'committed'. However, this BESS is to be connected to the 330 kV network and does not affect the identified need for this RIT-T.

We note also that if the proposed Mayfair solar farm and BESS go ahead near Gulgong, approximately 9 kilometres south-east of Beryl, this may alleviate some of the identified need. However, given this project is only in the early stages of development, we have not included is as part of the PADR assessment and do not consider at this stage that it affects the conclusions reached. We will assess it further in the PACR, if it has progressed further and appears likely to impact the RIT-T outcome.

While we note the Beryl BSP's proximity to the nearby Central West Orana (CWO) Renewable Energy Zone (REZ) being progressed by the NSW Government, new renewable generation connecting to this REZ will not have a material impact on the identified need for this RIT-T as it is outside the area in which the limits are observed.

2.2. Description of the identified need

The NER requires Transgrid to operate its network to satisfy reactive margin requirements (i.e., the maximum size of loading on a particular bus before its loading limit is expired and voltage collapse takes place). Specifically, under NER Schedule 5.1.8, Transgrid is required to ensure that the reactive power margin at any connection point is not less than 1% of the maximum fault level (in MVA) at the connection point.

Our planning studies show that there is currently a risk of breaching the NER requirements regarding reactive margin requirements in our network if an outage of Line 94B (Beryl – Wellington) occurs during both peak winter and summer demand (particularly at times of low or no local renewable generation). Without action, this would breach the defined reactive margin requirements in the NER, as well as result in substantial expected unserved energy to end consumers due to potential voltage collapse in the distribution network.

We are therefore undertaking this RIT-T to assess the options available for meeting our reactive margin requirements to avoid these consequences and continuing to maintain compliance with the relevant NER standards.

[23] https://ratchaustralia.com/projects/berylbess

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 5.1.8 of the NER.

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

2.3. Assumptions underpinning the identified need

This section describes the assumptions underpinning our assessment of the identified need. As part of the planning studies undertaken to identify the reactive margin constraints if no action is taken, assumptions were made regarding:

- general load at the Beryl BSP; and
- renewable generation and energy storage in the region.

The forecast reactive margin constraints are sensitive to these underlying assumptions.

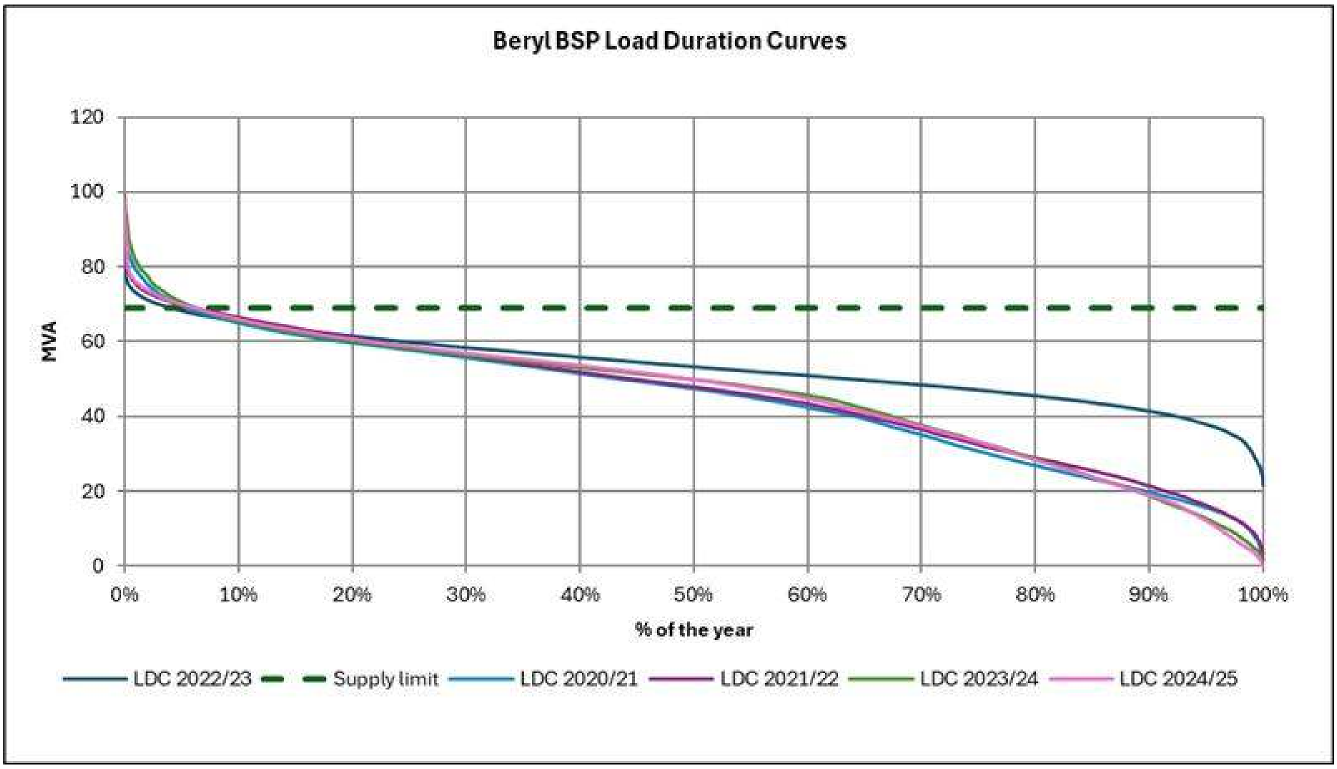
2.3.1. General load at the Beryl BSP

The demand forecasts have been updated since the PSCR using the latest forecasts provided by Essential Energy in January 2026, and are what we expect to use in our forthcoming 2026 TAPR.

Forecast maximum summer and winter demand for the Beryl BSP for 2025/26- 2034/35 is between 76 and 80 MW and 79 MW for the whole winter period, respectively.

The figure below presents the actual 2024/25, as well as the historical, load duration curves (LDCs) and demand limits for the Beryl BSP. The LDCs represent the net demand (i.e., total demand minus total renewable generation). Forecast LDCs have not been presented and are assumed to be effectively the same as that for 2024/25 given the lack of load change/growth forecast.

Figure 2.3 – Actual and historical LDCs and demand limits for the Beryl BSP



The LDCs show the percentage of the year, over the last five years, that actual demand at the Beryl BSP was above the calculated limit of 68 MW (which varies from 5% to 8% of the year).

The demand limit of 68 MW for Beryl BSP has been calculated based on the amount of pre-contingent load shedding required under normal system conditions to alleviate reactive margin issues following a contingent outage of Line 94B. Specifically, the limit has been calculated using winter 2024 data and it represents the MW value that can be supported during an outage of Line 94B in order to maintain a reactive margin above 1% of the maximum 3 phase fault level at the Beryl 132 kV busbar.

2.3.2. Renewable generation and energy storage in the region

We have identified reactive margin shortfalls in the Beryl area during a contingent outage of Line 94B, particularly when renewable generation is not dispatched (e.g., night peak when there is no output from solar PV generation and low output from the Crudine Ridge Wind Farm).

As noted above, there are a number of in-service and proposed renewable generator and energy storage systems in the region. Table 2-1 summarises these systems.

Table 2-1: Current and planned renewable generation and energy storage in the region

Connection	Connection location	Capacity	Status
Beryl Solar Farm	Beryl 66 kV	87 MW	In service
Crudine Ridge Wind Farm	132 kV Line 9ML	138 MW	In service
Bodangora Wind Farm	132 kV Line 94B	125 MW	In service

Connection	Connection location	Capacity	Status
Dunedoo Solar Farm	Essential Energy's network	55 MW	Anticipated
Bellambi Heights BESS	330 kV line 79	408 MW/916 MWh	Committed
Beryl BESS	Beryl 132 kV	100 MW/200MWh	Publicly announced
Mayfair Solar Farm and BESS	Essential Energy's network	60 MW solar farm and BESS	Publicly announced

We have taken account of all in-service renewable generation in assessing the identified need for this RIT-T. However, of the currently in-service generation:

- Beryl Solar Farm has an installed 15 MVAr harmonic filter, meaning it can automatically provide reactive power support even during the night time periods;
- Crudine Ridge Wind Farm has no filter but is assumed to be in service at all times (but sometimes with reduced or very low MW output due to weather conditions); and
- Bodangora Wind Farm would need to be tripped during an outage of Line 94B, due to it having a T-connection to Line 94B (i.e., when Line 94B trips, the wind farm will automatically be disconnected), and so cannot provide reactive support during these times.

Additional renewable generation could potentially assist with addressing/minimising the identified need if it can provide reactive support while generating active power, subject to its voltage control strategy (e.g., a new solar farm would need to have filters and leave them on overnight in order to assist).

While we note Beryl's proximity to the nearby CWO REZ being progressed by the NSW Government, new renewable generation connecting to this REZ will not have a material impact on the identified need for this RIT-T as it is outside the area in which the limits are observed.

The status of all renewable generation and storage projects in the region will be reviewed again prior to release of the PACR.

2.3.3. Reactive power margin shortfalls if action is not taken

Our system studies indicate that a reactive margin shortfall will arise around Beryl if action is not taken. As per the requirement under Schedule 5.1.8 of the NER, a minimum reactive power margin of 1% of the maximum fault level has to be maintained at each location. Accordingly, the minimum reactive power margin required at 132 kV is up to 10.9 MVAr and up to 7.9 MVAr at 66 kV.

The key change to this from the PSCR is that we have updated to demand forecasts to align with the latest provided by Essential Energy. This is an update provided since our TAPR 2025 and will be included (subject to any further updates) in our TAPR 2026.

3. Consultation on the PSCR

The PSCR and accompanying non-network EOI were released in November 2024. We subsequently received no general submissions to the PSCR, but received two submissions from non-network proponents to the EOI.

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

The proposed non-network solutions were:

- a currently in-service generator in the region which currently provides automatic reactive support through its filters, who submitted a proposal to leave its inverters on even in periods where it is not generating to provide additional support; and
- a proposed BESS which is able to provide reactive power.

The generator is estimated to provide approximately 15 MVAr of reactive power support automatically through its filters. We have factored this into the assessment for the base case in this PADR.

We have also been engaging with the generator proponent on their ability to provide additional support beyond that automatically provided, but we are unable to verify that this is technically feasible. To ultimately determine whether this solution is technically feasible, we would need detailed Power Systems Computer Aided Design (PSCAD) models from the proponent (which takes time and resources to prepare and assess). At this stage, detailed PSCAD models have not been provided by the proponent.

Further, we expect that, even if the generator leaving its inverters on is found to be technically feasible, it would not be sufficient to provide the reactive support by itself (we estimate the reactive support gap to be in the order of around 30 MVAr). At this time, we therefore do not expect that there will be a need to draw on this solution to provide additional reactive support and, as a result, we have not considered this proposal further. This has been communicated to the generator proponent.

The proposed BESS is estimated to provide approximately 40 MVAr of reactive power support automatically via its access standard, which, in addition to the 15 MVAr from the generator's filter, would be sufficient to meet the identified need.

While the proponent expects the BESS to be in-service by October 2028, Transgrid's assessment at this point in time based on information provided by the proponent is that the BESS is not yet sufficiently advanced to be considered 'committed' or 'anticipated' by reference to the criteria set out under the RIT-T. However, we have also investigated a sensitivity where the BESS is assumed to meet these criteria (and ultimately proceed irrespective of this RIT-T), in order to assess whether the RIT-T outcome would be affected if the BESS does meet the criteria to be 'anticipated' or 'committed' in the near future.

As noted in section 2.3.2, the status of all renewable generation and storage projects in the region will be reviewed again prior to release of the PACR.

4. Credible options that meet the identified need

We consider credible options in this RIT-T assessment as those that would meet the identified need from a technical, commercial, and project delivery perspective.[24]

The credible options considered in this PADR assessment have been refined since the PSCR to reflect submissions to the EOI and additional analysis by Transgrid. Further details of why some options identified in the PSCR are no longer considered are provided in section 4.4.

Table 4-1 provides a summary of the three credible options assessed in this PADR.

Table 4-1: Summary of the credible options considered at this stage, $2025/26

Option	Description	Capital cost ($m)	Commissioning
1	Install a 60 MVA synchronous condenser at Beryl	52.4	2029/30
2	Install an SVC of +50 MVAr to -10 MVAr at Beryl	44.1	2029/30
3	Non-network BESS	93.2[25]	October 2028

For the synchronous condenser and Static Var Compensator (SVC), we have assumed an annual operating and maintenance of 0.6% of the upfront capital expenditure. For the non-network BESS, we have assumed annual operating and maintenance costs consistent with that assumed in the 2026 integrated system plan (ISP).[26]

None of the credible options listed above are expected to have a material inter-regional impact.

The remainder of this section provides more detail on each of the above three potential credible options, as well as a number of other options considered but not progressed (Section 4.4.). It first presents a description of the 'do nothing' base case against which all credible options are required to be assessed in this PADR analysis under the RIT-T.

All costs presented in this PADR are in real 2025/26 dollars, unless otherwise stated.

4.1. Base case

Consistent with the RIT-T requirements, the assessment undertaken in this PADR compares the costs and benefits of each option to a base case. The base case is the (hypothetical) projected case if no action is taken, i.e.[27]

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

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

[25] Since the BESS is not yet considered 'committed' or 'anticipated' under the RIT-T, its full capital (and operating) cost are included in the PADR assessment, consistent with the RIT-T framework.

[26] Specifically, $13.54/kW (real 2024/25) year of fixed operating costs and no variable operating costs, inflated to real 2025/26 terms. See: AEMO, *2025-inputs-and-assumptions-workbook.xlsm,* version 7.4, 28 August 2025, 'Fixed OPEX' and 'Variable OPEX' sheets.

[27] AER, *Regulatory investment test for transmission application guidelines – October 2023*, p 22.

Under the base case, no proactive investment is made to address the emergence of reactive margin shortfalls, which will result in Transgrid breaching system standard obligations set out in the NER (and significant expected unserved energy to end consumers).

While we would never plan for this situation to eventuate, the RIT-T requires all credible options to be assessed against a common base case representing a state of the world where action is not taken to address the identified need. In reality, we are planning to have the most efficient solution in-place (which will be identified through this RIT-T process) to continue to provide reliable supply to the load in question.

As stated in section 3 above, we have factored in approximately 15 MVAr of reactive power support under the base case from a currently in-service generator in the region. This generator currently provides this reactive support automatically through its filters.

4.2. Option 1 – 60 MVA synchronous condenser

Option 1 involves the installation of a new 60 MVA synchronous condenser, connected to the 132 kV busbar at Beryl substation.

The specific scope of this option includes:

- installation of a new 60 MVA 132/11 kV transformer;
- installation of a new 11 kV/415 V auxiliary transformer;
- installation of a new 60 MVA synchronous condenser and associated secondary systems;
- installation of a new building housing the synchronous condenser and associated equipment and control room with associated control and protection panels and LV switchgear;
- extension of an existing switchyard bench;
- installation of a new 132 kV switch bay and secondary systems;
- installation of a new spill oil tank;
- upgrade of an auxiliary transformer; and
- modification of existing protection scheme.

The scope of works for this option is expected to be carried out between 2025/26 and 2029/30, with the expected commissioning date for this option being 2029/30.

The estimated capital cost of this option is approximately $52.4 million, comprising:[28]

- $3.1 million in labour costs;
- $34.4 million materials costs; and
- $14.9 million in expenses (which includes expenses in relation to contractors, design consultants etc).

[28] Numbers may not add perfectly due to rounding.

The estimated capital cost associated with material costs and expenses can be further broken down as follows:

- $2.5 million for the switchyard extension;
- $44.1 million for the synchronous condenser; and
- $2.7 million for all other equipment.

Please note that, while we have provided a component-level breakdown of the estimated capital costs for Option 1 (and all other options), these individual estimates cannot be used to estimate similar component costs in other contexts.

Table 4-2 shows the expected capital expenditure profile of this option.

Table 4-2: Annual breakdown of Option 1's expected capital cost, $m

	2025/26	2026/27	2027/28	2028/29	2029/30
Capital expenditure	0.2	1.2	4.2	25.4	21.4

4.3. Option 2 – SVC of +50 MVAr to -10 MVAr

Option 2 involves the construction of a new SVC at Beryl with a range of +50 MVAr to -10 MVAr.

Option 2 is a refinement of Option 4 in the PSCR following further assessment by Transgrid concluding that an SVC is preferable to STATCOM. This is because this technology currently exists on our network.

The specific scope of this option includes:

- extension of existing switchyard bench and existing bus section to accommodate the new SVC switchbay;
- installation of a new 132 kV transformer switchbay and associated secondary systems; and
- installation of new 132/33 kV transformer and new spill oil tank and modification of existing protection schemes.

The scope of works for this option is expected to be carried out between 2025/26 and 2029/30, with the expected commissioning date for this option being 2029/30.

The estimated capital cost of this option is approximately $44.1 million, comprising:

- $4.7 million in labour costs;
- $26.4 million materials costs; and
- $13.0 million in expenses (which includes expenses in relation to contractors, design consultants etc).

The estimated capital cost associated with material costs and expenses can be further broken down as follows:

- $2.4 million for the switchyard extension;
- $36.3 million for the SVC; and

- $1.6 million for all other equipment.

Table 4-3 shows the expected expenditure profile of this option.

Table 4-3: Annual breakdown of Option 2's expected capital cost, $m

	2025/26	2026/27	2027/28	2028/29	2029/2030
Capital expenditure	0.2	1.0	3.5	21.4	18.0

4.4. Option 3 – 100 MW / 200 MWh non-network BESS in the Beryl area

Option 3 is a non-network option that involves the use of a BESS to provide the required support. Specifically, the BESS proposed in response to the PSCR and concurrent EOI is estimated to provide approximately 40 MVAr of reactive power support automatically via the requirements in its access standard, which would be sufficient to meet the identified need.

While recent communication with the BESS proponent indicates that they expect the BESS to be in-service by October 2028, Transgrid's assessment at this point in time based on information provided by the proponent is that it is not yet sufficiently developed to be considered 'committed' or 'anticipated' by reference to the criteria set out in the RIT-T. We have therefore not assumed that the BESS goes ahead under the 'do nothing' base case and the assessment consequently captures the full cost of the project in the option case, consistent with the RIT-T framework.

While Transgrid has asked the proponent for cost estimates for the BESS, they have not been provided to-date given the current development stage of the project.

We therefore have adopted indicative construction assumptions for the BESS consistent with those in the latest AEMO Inputs, Assumption and Scenarios Report (IASR). Specifically, we have assumed:

- a 100 MW BESS capacity (and an assumed 2-hour duration);
- a capital cost of $93.2 million;[29]
- an annual operating and maintenance cost of $1.4 million/year;[30] and
- a twenty-year asset life.[31]

To convert the ISP cost assumptions, which are in real 2024/25 terms, to 2025/26 prices we have increased the ISP cost assumptions by inflation for the year ended June 2025.

For the purposes of this PADR assessment, we have estimated the avoided unserved energy for 2028/29 according to the expected commissioning date for the BESS (i.e., October 2028).[32]

In addition, we have also investigated a sensitivity where the BESS is assumed to ultimately proceed irrespective of this RIT-T in order to assess whether the RIT-T outcome would be affected if the BESS meets

[29] Calculated as $914.43/kW (real 2024/25) * 1000 * 100MW = $91.443 million (real 2024/25), which equals $93.168 million in 2025/26 dollars. See: AEMO, *2025-inputs-and-assumptions-workbook.xlsm*, version 7.4, 28 August 2025, 'Build costs' sheet; and ABS, *CPI Australia, all groups (series ID A130393720C)*.

[30] Calculated as 13.54/kW (real 2024/25) * 1000 * 100MW = $1.354 million (real 2024/25), which equals $1.379 million in 2025/26 dollars. See: AEMO, *2025-inputs-and-assumptions-workbook.xlsm*, version 7.4, 28 August 2025, 'Fixed OPEX' and 'Variable OPEX' sheets; and ABS, *CPI Australia, all groups (series ID A130393720C)*.

[31] Based on the economic and technical life for a 2 hour battery. See: AEMO, *2025-inputs-and-assumptions-workbook.xlsm,* version 7.4, 28 August 2025, 'Lead time and project life' sheet.

[32] Specifically, we have pro-rated the estimated avoided unserved energy under the base case for 2028/29 according to the proponent's expected commissioning date for the BESS (i.e., October 2028).

the criteria to be ‘anticipated’ or ‘committed’ in the near future. We will continue to engage with the proponent to understand the progression of this proposal, and the degree of certainty around the in-service date.

4.5. Options considered but not progressed

We also considered whether other options could meet the identified need. Reasons these options were not progressed are summarised

Table 4-4.

Table 4-4: Options considered but not progressed

Description	Reason(s) for not progressing
Development of new 330/132 kV substation at Beryl	Transgrid initially considered establishing a new substation at Beryl to resolve constraints and improve system capacity. However, subsequent investigations have indicated that a new substation at Beryl will not be able to address the identified need due to this option causing thermal overloading in the 132 kV network as a result of recent generator connections to the 330 kV lines between Wollar and Wellington. This option is therefore not considered technically feasible.
Installation of additional capacitor banks at Beryl substation	Transgrid investigated whether the addition of a fourth capacitor bank at Beryl would alleviate the constraints. However, the option was deemed technically infeasible since it would not address the issues during an outage of Line 94B during low levels of renewable generation.
Construct a new line adjacent to existing Line 94B	This option was identified as a potential credible option in the PSCR. Transgrid no longer considers construction of an additional line a credible option as compared to the other identified potential credible options construction of a new line has significantly higher expected construction costs without a commensurate increase in expected market benefits.
Construct and operate a network BESS at Beryl	This option was identified as a potential credible option in the PSCR. While Transgrid still considers a BESS as a potential credible option, one of the non-network options proposed in response to the EOI is a BESS. Transgrid considers the non-network option proponent is better placed than Transgrid to construct and operate a BESS. Further, the non-network option proponent is further advanced in its planning processes and may meet the RIT-T criteria for an ‘anticipated’ or ‘committed’ project ahead of the PACR. We have therefore assessed the proponent’s proposed BESS as a credible option instead of a network BESS.

5. Materiality of market benefits

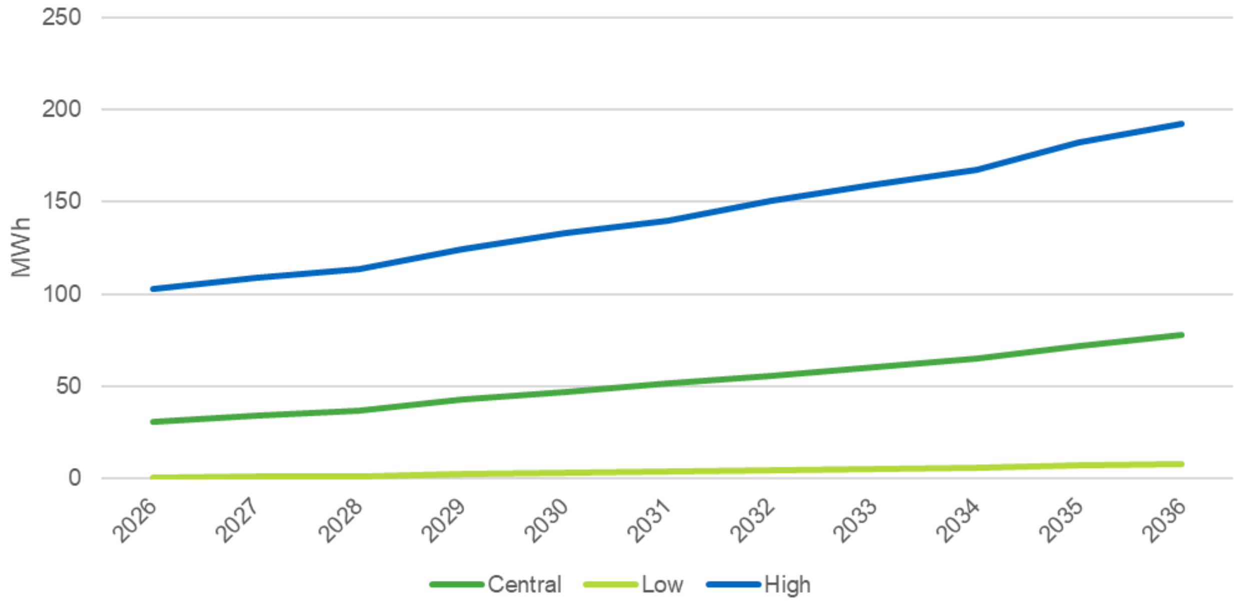
This section outlines the categories of market benefits prescribed in the NER and whether they are considered material for this RIT-T.[33]

5.1. Changes in involuntary load curtailment are material for this RIT-T assessment

We consider that changes in involuntary load shedding are material for the credible options in this RIT-T assessment. Under the base case, significant involuntary load shedding is expected to occur during a contingent outage of Line 94B, particularly under the high demand forecast.

The figure below shows the estimated unserved energy under each of the three demand forecasts over the next ten years. The underlying demand forecasts have been updated since the PSCR using the latest forecasts provided by Essential Energy in January 2026, and align with what we expect to use in our forthcoming 2026 TAPR.

Figure 5.1 Expected unserved energy forecast under each demand forecast



As part of this PADR assessment, we have estimated the value of avoided expected unserved energy under each of the credible options, compared to the base case. This is valued using the Value of Customer Reliability (VCR) for Beryl that is based on the AER's latest VCR estimates (as outlined in Section 6.3 below).

5.2. Wholesale market benefits have not been assessed in the PADR but will be considered further for the BESS option

The following wholesale market benefits are not considered material for the network options assessed in this RIT-T:

[33] The NER requires that all classes of market benefits identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific class (or classes) is unlikely to be material in relation to the RIT-T assessment for a specific option – NER clause 5.15A.2(b)(5). See Appendix A for requirements applicable to this document.

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in Australian greenhouse gas emissions;
- changes in voluntary load curtailment;
- changes in costs for parties other than Transgrid;
- differences in the timing of unrelated network expenditure;
- changes in ancillary services costs;
- changes in network losses; and
- competition benefits.

The BESS under Option 3 would be capable of impacting the wholesale market, and so may give rise to wholesale market benefits.

As this draft stage we have taken a proportionate approach and not modelled the expected impact of the BESS on the wholesale market. Specifically, the approach taken in the PADR is to assess how close the net market benefits are between the network options and the BESS without considering the potential wholesale market benefits, in order to assess whether estimation of these benefits is warranted. It is also possible that the BESS may become sufficiently advanced to be considered 'anticipated' prior to the PACR, which would then not require wholesale market modelling to be undertaken.[34]

We intend to consider the extent of materiality of any wholesale market benefits for Option 3 further in the PACR, in light of the latest information available at that time.

5.3. No other classes of market benefits are material

In addition to the classes of market benefits discussed above, NER clause 5.15A.2(b)(4) requires us to consider the following classes of market benefits, listed in Table 5-1, arising from each credible option. We consider that none of the classes of market benefits listed are material for this RIT-T assessment for the reasons outlined below.

Table 5-1: Market benefits categories considered not material

Market benefits	Reason
Difference in the timing of unrelated network expenditure (outside of any benefits of this nature driven by wholesale market changes)	We do not expect any of the credible options to affect the need for any unrelated network expenditure.
Option value	We note the AER's view that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change.[35] We note that no credible option is sufficiently flexible to respond to change or uncertainty for this RIT-T. We therefore do not consider there to be any option value with the options considered in this RIT-T.

[34] Specifically, and as outlined in section 7.4.2, we understand that the BESS would not need to change its build or operation at all if it goes ahead in order to provide the required services. The implication of this is that, if the BESS is assumed to proceed irrespective of this RIT-T, then wholesale market benefits from it are considered immaterial (i.e., since it exists equally in the base case and option case).

[35] AER, *Regulatory Investment Test for Transmission – Application Guidelines*, November 2024, p. 56-57.

6. Overview of the assessment approach

This section outlines the approach that we have applied in assessing the net benefits associated with the credible option against the base case as part of the PADR.

6.1. Assessment period and discount rate

A 20-year assessment period, from 2025/26 to 2044/45, has been adopted for this RIT-T analysis. This period takes into account the size, complexity and expected asset life of the assets.

Where the capital components have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining functional asset life. This ensures that the capital cost of long-lived assets over the assessment period is appropriately captured, and that all assets have their costs assessed over a consistent period, irrespective of type, technology or serviceable asset life.

A real, pre-tax discount rate of 7% is adopted as the central assumption for the NPV analysis, consistent with AEMO's latest IASR.[36]

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 therefore test the sensitivity of the results to a lower bound discount rate equal to 4.18%,[37] and an upper bound discount rate of 10 per cent (being the upper bound in the 2025 IASR).

6.2. Approach to estimating option costs

We have estimated the network capital costs based on the scope of works necessary together with costing experience from previous projects of a similar nature. The non-network BESS costs have been estimated using the cost assumptions used for the draft 2026 ISP (as outlined in section 4.4 above).

All network costs estimated by Transgrid's project development team use the estimating tool 'MTWO'. The MTWO cost estimating database reflects actual outturn costs built up over more than 10 years from:

- period order agreement rates and market pricing for plant and materials;
- labour quantities from recently completed project; and
- construction tender and contract rates from recent projects.

The MTWO estimating database is reviewed annually to reflect the latest outturn costs and confirm that estimates are within their stated accuracy range and represent the most likely expected cost of delivery (P50 costs[38]). As part of the annual review, Transgrid benchmarks the outcomes against independent estimates provided by various engineering consultancies.[39]

---

36 AEMO, *2025 Inputs, Assumptions and Scenarios Report*, July 2025, p. 159.
37 This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (Directlink) as of the date of this analysis, see: AER, April 2025, Directlink – 2025-30 – Final decision – PTRM.
38 i.e., there is an equal likelihood of over- or under-spending the estimate total.
39 For further detail on our cost estimating approach refer to section 7 of our Augmentation Expenditure Overview Paper submitted with our 2023-28 Revenue Proposal.

Transgrid does not generally apply the Association for the Advancement of Cost Engineering (AACE) international cost estimate classification system to classify cost estimates. Doing so for this RIT-T would involve significant additional costs, which would not provide a corresponding increase in benefits compared with the use of MWTO estimates and so this has not been undertaken.

We estimate that actual network costs will be within +/- 25% of the central capital cost estimate. While we have not explicitly applied the AACE cost estimate classification system, we note that an accuracy of +/- 25% for cost estimates is consistent with industry best practice and aligns with the accuracy range of a ‘Class 4’ estimate, as defined in the AACE classification system.

No specific contingency allowance has been included in the cost estimates.

All cost estimates are prepared in real, 2025/26 dollars based on the information and pricing history available at the time that they were estimated. The cost estimates do not include or forecast any real cost escalation for materials.

For options based at the Beryl substation, no additional access has been considered as the work is constrained to operational substations. Bench extension work will be required, and normal soil has been considered for this work.

6.3. Value of customer reliability

We have estimated expected unserved energy at Beryl under the base case and for each of the credible options.

The avoided unserved energy for each option has been valued using the estimated VCR values published by the AER.[40] Specifically, we have developed a load-weighted VCR estimate for Beryl of $17.37/kWh using the AER VCR values for the customer groups relevant to the region as shown in the table below.

Table 6-1: Beryl load weighted VCR breakdown ($2025/26)

	Residential	Commercial	Mining	VCR
AER VCR estimate[41]	$39.99/kWh	$35.70/kWh	$11.04/kWh	$17.37
Beryl load breakdown	21%	1%	78%	

We have also applied VCR estimates that are 30% lower and 30% higher as part of our sensitivity testing, consistent with the AER’s most recent specified +/- 30% confidence interval.[42]

40 The VCR values have been taken from the most recent VCR update from the AER, i.e.: AER, *Values of customer reliability 2025 annual adjustment summary*, December 2025.

41 The VCR values are substantially different to those reported in the PSCR due to the AER’s 2024 Values of Customer Reliability update which saw the NSW residential VCR increase, and the commercial and mining VCRs decrease substantially. The AER’s 2025 update reflects the 2024 VCR values adjusted for inflation. See AER, Values of Customer Reliability – Final Report on VCR values, December 2024, pp 5-6; and AER, *Values of customer reliability 2025 annual adjustment summary*, December 2025.

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

6.4. The options have been assessed against three reasonable scenarios

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

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit. It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options are assessed under three scenarios as part of this PADR assessment. For this RIT-T, the only market benefit considered to be material at this stage is changes in involuntary load shedding. As a result, the three PADR scenarios differ only through their assumed demand forecasts.

Given that wholesale market benefits have not been estimated in this PADR assessment, the three scenarios implicitly assume the expected most likely scenario for the 2026 ISP (i.e., the 'Step Change' scenario).

Table 6.2 sets out the three scenarios, and the underlying variables.

Table 6.2 Summary of scenarios

Variable/scenario	Central demand scenario	Low demand scenario	High demand scenario
Scenario weighting	1/3	1/3	1/3
Demand growth	Central forecast (from section 5.1)	Low forecast (from section 5.1)	High forecast (from section 5.1)
Discount rate	7%	7%	7%
VCR ($/kWh)	17.37	17.37	17.37
Network capital costs	Base estimate	Base estimate	Base estimate

The effect of changes to other variables (i.e., the discount rate, VCR and capital costs) on the NPV results has been investigated in the sensitivity analysis as part of the PADR. We consider this to be consistent with the AER guidance for RIT-Ts of this type.[43,44]

Given the results of the PADR assessment show the same option is preferred in all three scenarios, the weights applied to each scenario are not material at this draft stage. We have therefore adopted a proportionate approach by weighting the three scenarios equally, and have not sought to develop more specific weights.

[43] AER, *Regulatory Investment Test for Transmission – Application Guidelines*, November 2024, pp. 42-44.
[44] See: AER, *Decision: North West Slopes and Bathurst, Orange and Parkes Determination on dispute - Application of the regulatory investment test for transmission*, November 2022, pp. 18-20 & 31-32, as well as with the AER's RIT-T Guidelines.

7. Assessment of credible options

This section outlines the assessment we have undertaken of the credible options. The assessment compares the costs and benefits of each credible option to the base case.

All costs and benefits presented in this PADR are in 2025/26 dollars.

7.1. Estimated gross market benefits

Table 7.1 below summarises the present value of the gross benefits of the credible options under the three scenarios.

The benefits included in the assessment are the estimated reduction in involuntary load shedding and are shown to be equivalent for Option 1 and Option 2, given their same assumed commissioning date, while the gross market benefits are marginally higher for Option 3 due to its earlier assumed commissioning date.

Table 7.1: Present value of gross market benefits ($m)

Option/scenario	Central demand	Low demand	High demand	Weighted
Scenario weighting	1/3	1/3	1/3	
Option 1 – syncon	8.4	0.8	21.4	10.2
Option 2 – SVC	8.4	0.8	21.4	10.2
Option 3 – BESS	9.5	0.9	24.5	11.6

7.2. Estimated costs

Table 7.2 summarises the present value of capital costs of each credible option relative to the base case.

The present value of capital costs are the same in each case given the scenarios only differ by the assumed load forecast (as outlined in section 6.4).

Table 7.2: Present value of capital and operating costs by option (present value, $ millions)

Option/scenario	Present value, $ millions
Option 1 – syncon	-35.2
Option 2 – SVC	-29.9
Option 3 – BESS	-86.8

7.3. Estimated net market benefits

Table 7.3 below presents the net present value for each option across the three scenarios modelled, and on a weighted basis. It also shows the ranking of the options in parentheses for each case.

Option 2 is found to be the top-ranked option in all scenarios. On a weighted basis, Option 2 is found to deliver net market benefits that are approximately $5.3 million and $55.5 million higher, in present value terms, than Option 1 and Option 3, respectively.

Table 7.3: Present value of the net market benefits for each option (present value, $ millions)

Option/scenario	Central demand	Low demand	High demand	Weighted
Scenario weighting	1/3	1/3	1/3	
Option 1 – syncon	-26.8 (2)	-34.4 (2)	-13.8 (2)	-25.0 (2)
Option 2 – SVC	**-21.5** **(1)**	**-29.1** **(1)**	**-8.5** **(1)**	**-19.7** **(1)**
Option 3 – BESS	-77.3 (3)	-85.9 (3)	-62.3 (3)	-75.2 (3)

Given this RIT-T is a reliability corrective action, the preferred option is permitted to have negative estimated net market benefits.[45]

While the wholesale market benefits of the BESS under Option 3 have not been estimated at this stage (as outlined in section 5.2), we note that, if included, they would add to the expected net market benefits of Option 3. We intend to consider the materiality of these expected benefits further as part of the PACR, and whether the inclusion of market benefits would impact the option rankings.

7.4. Sensitivity testing

We have undertaken sensitivity testing to examine how the net economic benefit of the credible options changes with respect to changes in key assumptions.

7.4.1. General sensitivity testing of the overall estimated net benefits

We have investigated how the estimated net benefits change under the following alternate assumptions:

- a 25 per cent increase/decrease in the assumed network capital costs;
- a 25 per cent increase/decrease in the assumed non-network capital costs;
- lower discount rate of 4.18 per cent as well as a higher rate of 10 per cent; and
- a 30 per cent increase/decrease in the VCR.

We present the results of each of the sensitivities in the figures below. Option 2 is found to be ranked ahead of the other two options for all sensitivities investigated.

[45] As stipulated in clause 5.15A.1 of the NER.

Figure 7.1 Network capital cost sensitivity

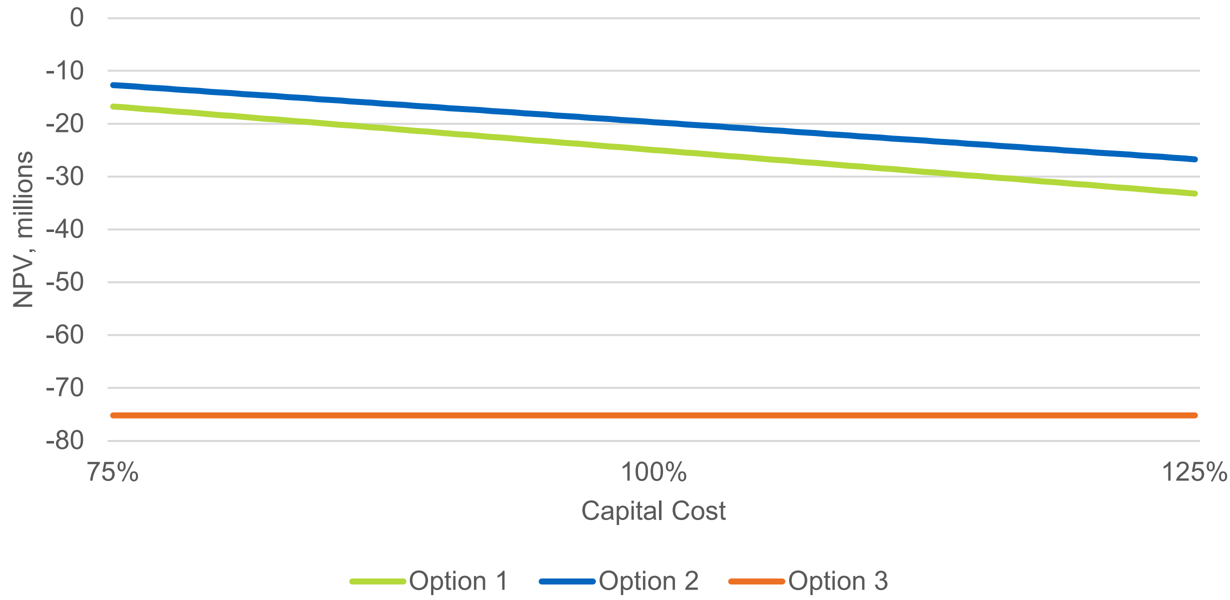


Figure 7.2 Non network capital cost sensitivity

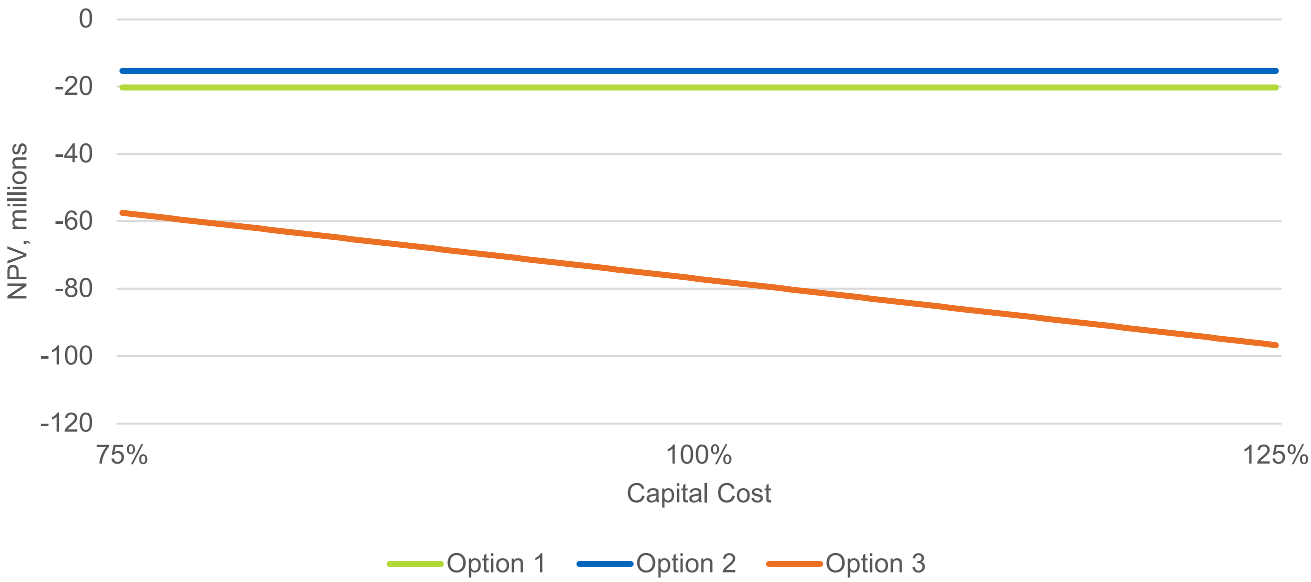


Figure 7.3 Discount rate sensitivity

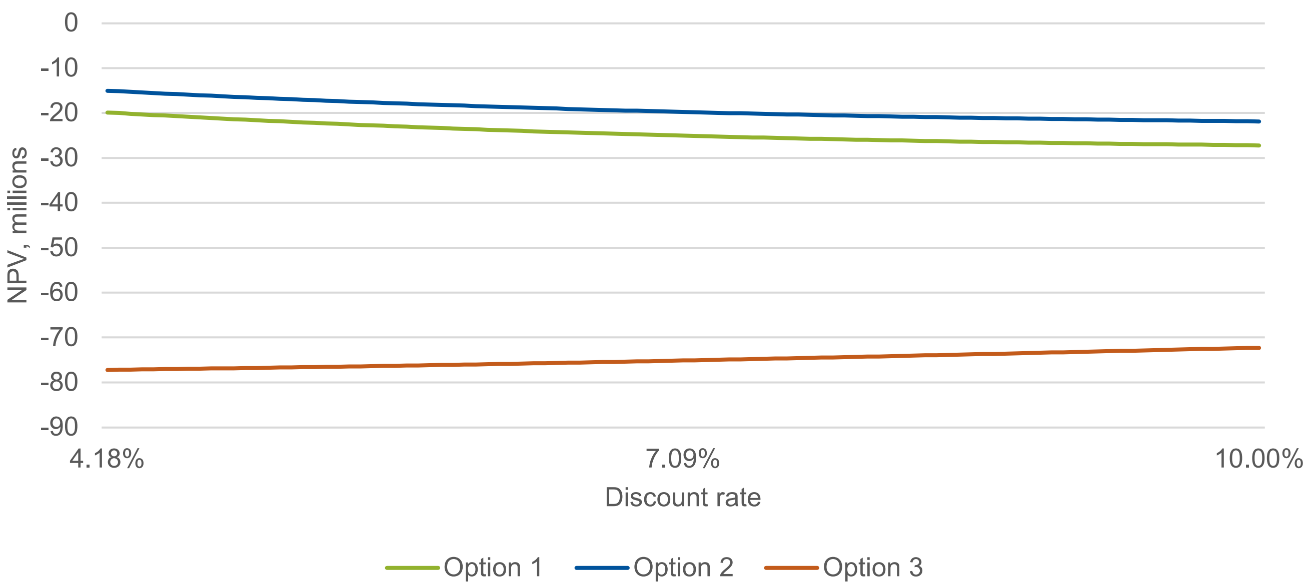
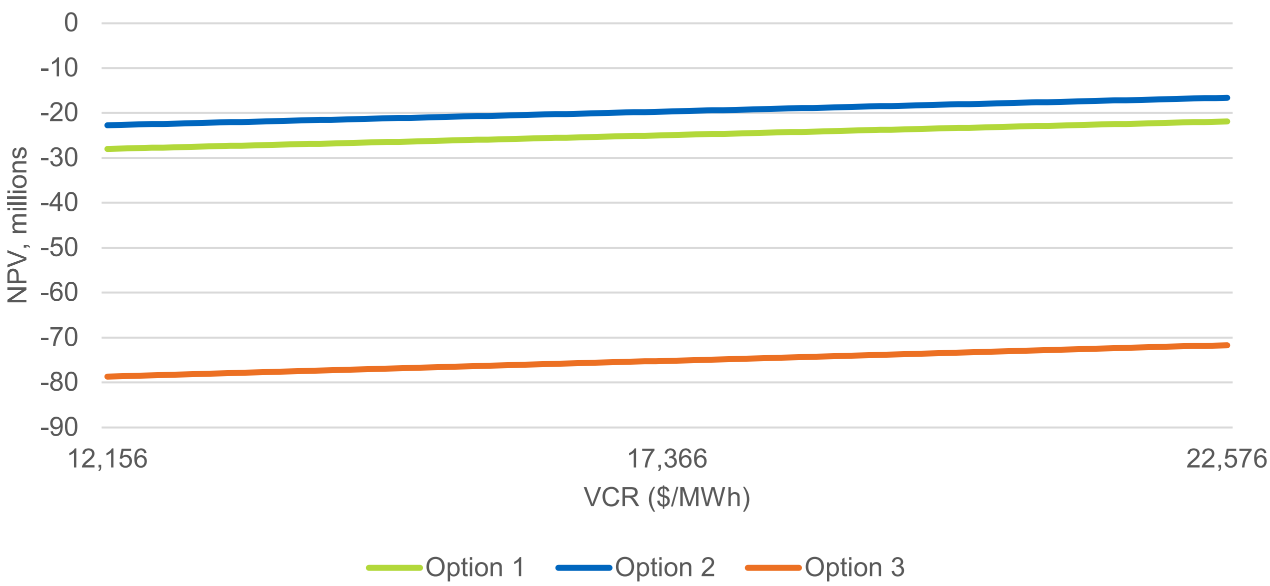


Figure 7.4 VCR sensitivity



The above sensitivity testing indicates that Option 2 is the top-ranked option under all sensitivities investigated. We also find that no realistic boundary values exist that would change this result.

7.4.2. The proposed BESS becoming 'anticipated' or 'committed'

Option 3 is a non-network option that involves the use of this proposed BESS to provide the required support.

While the proponent expects the BESS to be in-service by October 2028, Transgrid's assessment at this point in time based on information provided by the proponent is that the BESS is not yet sufficiently advanced to be considered 'committed' or 'anticipated' by reference to the criteria set out under the RIT-T. We have therefore not assumed that the BESS goes ahead under the 'do nothing' base case in the core assessment above, consistent with the RIT-T framework, and thus have captured the full cost of the project in the assessment (but not the wholesale market benefits, as outlined in section 5.2).

However, we have also investigated a sensitivity where the BESS is assumed to ultimately proceed irrespective of this RIT-T (i.e., where it is considered 'anticipated' or 'committed'). The key implication under the sensitivity is that the capital and operating costs of the BESS are assumed under the base case (as well as the associated wholesale market impacts).

Under these assumptions, Option 3 would become preferred over the other two options, as shown in the table below. The BESS would resolve the identified need under the base case and there would be no need to undertake any network option (hence, the network option net benefits below are just the present value of their costs, as they would not provide any additional benefits in terms of reduced unserved energy).

Table 7.4: Present value of the net market benefits for each option ($ millions)

Option/scenario	Central demand	Low demand	High demand	Weighted
Scenario weighting	1/3	1/3	1/3	
Option 1 – syncon	-35.2	-35.2	-35.2	-35.2
Option 2 – SVC	-29.9	-29.9	-29.9	-29.9
Option 3 – BESS	**0.0**	**0.0**	**0.0**	**0.0**

We understand that the BESS would not need to change its build or operation at all if it goes ahead in order to provide the required services. The implication of this is that, if the BESS is assumed to proceed irrespective of this RIT-T, then any wholesale market benefits from it are considered immaterial (i.e., since it exists equally in the base case and option case).

We will continue to engage with the proponent of this BESS to understand the progression of this proposal, as well as the degree of certainty around the in-service date.

8. Draft conclusion

This PADR finds that Option 2 is the preferred option for managing reactive margin requirements and continuing to maintain compliance with the relevant NER standards.

Option 2 involves the construction of a new SVC at Beryl with a range of +50MVAr to -10MVAr.

The specific scope of this option includes:

- extension of existing switchyard bench and existing bus section to accommodate the new SVC switchbay;
- installation of a new 132 kV transformer switchbay and associated secondary systems; and
- installation of new 132/33 kV transformer and new spill oil tank and modification of existing protection schemes.

The scope of works for this option is expected to be carried out between 2025/26 and 2029/30, with the expected commissioning date for this option being 2029/30. The estimated capital cost of this option is approximately $44.1 million.

Option 2 is the preferred option at this stage of the RIT-T in accordance with NER clause 5.15A.2(b)(12) because it is the credible option that maximises the net present value of the net economic benefit. Option 2 remains preferred under all the sensitivities undertaken, with the exception of the sensitivity where the BESS is assumed to proceed irrespective of this RIT-T. The analysis undertaken and the identification of Option 2 as the preferred option satisfies the RIT-T.

However, if the proponent of the BESS is able to provide Transgrid with credible evidence that it meets the definition of either 'anticipated' or 'committed' (by reference to the criteria set out under the RIT-T), and sufficient assurance that the reactive support will be in-service by the assumed October 2028 date, then Option 3 may become the preferred option for this RIT-T.

We will continue to liaise with the proponent of this solution and ensure that the latest information available is reflected in the PACR analysis. In particular, we will be seeking from the BESS proponent further credible evidence regarding:

- the progress of the BESS against the criteria for 'committed' status under the RIT-T; and
- assuming it does not meet this status, the expected costs of the project in order to base the PACR assessment on more specific cost estimates (i.e., as opposed to the generic, non-locational ISP costs used in this PADR).

Overall, given this is a reliability corrective action RIT-T, Transgrid requires a high degree of certainty that the BESS will be commissioned on-time for Option 3 to ultimately be preferred. We would therefore require the proponent to provide sufficient assurance regarding the BESS development timeframes, irrespective of whether it is considered 'anticipated' or 'committed' under the RIT-T, for it to be considered as the ultimately preferred option.

Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PADR with the requirements of the NER version 243.

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

In addition, the table below outlines a separate compliance checklist demonstrating compliance with the binding guidance in the latest AER RIT-T guidelines.

Guidelines section	Summary of the requirements	Relevant section(s)
3.2.5	A RIT-T proponent must consider social licence issues in the identification of credible options. A RIT proponent should include information in its RIT reports about when and how social licence considerations have affected the identification and selection of credible options.	N/A[46]
3.4.3	The value of emissions reduction (VER), reported in dollars per tonne of emissions (CO2 equivalent), is used to value emissions within a state of the world. A RIT-T proponent is required to use the then prevailing VER under relevant legislation or, otherwise, in any administrative guidance.	N/A[46]
3.5A.1	Where the estimated capital costs of the preferred option exceeds $103 million (as varied in accordance with a cost threshold determination), a RIT-T proponent must, in a RIT-T application: • outline the process it has applied, or intends to apply, to ensure that the estimated costs are accurate to the extent practicable having regard to the purpose of that stage of the RIT-T • for all credible options (including the preferred option), either: > apply the cost estimate classification system published by the AACE, or > if it does not apply the AACE cost estimate classification system, identify the alternative cost estimation system or cost estimation arrangements it intends to apply, and provide reasons to explain why applying that alternative system or arrangements is more appropriate or suitable than applying the AACE cost estimate classification system in producing an accurate cost estimate.	NA[47]
3.5A.2	For each credible option, a RIT-T proponent must specify, to the extent practicable and in a manner which is fit for purpose for that stage of the RIT-T: • all key inputs and assumptions adopted in deriving the cost estimate • a breakdown of the main components of the cost estimate • the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates) • the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied • the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance	4 & 6.2
3.5	In the RIT-T, costs must include the following classes: • Costs incurred in constructing or providing the credible option • Operating and maintenance costs over the credible option's operating life • Costs of complying with relevant laws, regulations and administrative requirements For, asset replacement projects or programs, there are costs resulting from removing and disposing of existing assets, which a RIT-T assessment should recognise. RIT-T proponents should include these costs in the costs of all credible options that require removing and disposing of retired assets. For completeness, the RIT-T proponent would exclude these costs from the 'BAU' base case.	4

46 These are new requirements stipulated in revised RIT-T Application Guidelines released by the AER, which came into effect on 21 November 2024. For compliance purposes, the AER only have regard to the guidance that was in effect when Transgrid initiated the RIT-T in question. In this context, initiated means from the publication of a PSCR. As the PSCR was published prior to 21 November 2024, these new requirements are not applicable to this RIT-T.

47 The cost threshold of $103 million has been updated in the new guidelines from the previous value of $100 million. In accordance with footnote 46, the previous cost threshold applies.

Guidelines section	Summary of the requirements	Relevant section(s)
3.5.3	The RIT-T proponent is required to provide the basis for any social licence costs in its RIT-T reports and may choose to refer to best practice from a reputable, independent and verifiable source.	N/A[46]
3.6	RIT-T proponents are required to apply classes of market benefits consistently across all credible options.	5[46]
3.7.3	When calculating the benefit from changes in Australia's greenhouse gas emissions, a RIT-T proponent is required to: • include the following emissions scopes, unless the change relative to the base case can be demonstrated to be immaterial to the RIT outcome: • direct emissions from generation • direct emissions other than from generation • estimate the change in annual emissions (once identified in accordance with this Guideline) between the base case and the credible option, and multiplying this change by the annual VER to arrive at the annual benefit from changes in Australia's greenhouse gas emissions	N/A[46]
3.8.2	Where the estimated capital cost of the preferred option exceeds $103 million (as varied in accordance with an applicable cost threshold determination), a RIT-T proponent must undertake sensitivity analysis on all credible options, by varying one or more inputs and/or assumptions.	N/A
3.9.4	If a contingency allowance is included in a cost estimate for a credible option, the RIT-T proponent must explain: • the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to, and • how the level or quantum of the contingency allowance was determined.	N/A
3.11.2	Where a concessional finance agreement is included, the RIT-T proponent is required to provide sufficient detail about the concessional finance agreement to justify an agreement's inclusion and such that it can articulate how the value of the concession is to or would be shared with consumers. If a proponent seeks to include an unexecuted concessional finance agreement in the RIT-T, they must undertake sensitivity testing for the scenario the agreement doesn't eventuate.	N/A[46]
4.1	RIT-T proponents are required to describe in each RIT-T report • how they have engaged with local landowners, local council, local community members, local environmental groups or traditional owners and sought to address any relevant concerns identified through this engagement • how they plan to engage with these stakeholder groups, or • why this project does not require community engagement.	N/A[46]