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Complying with reactive margin requirements at Beryl

RIT-T Project Specification Consultation Report

Region: Central West NSW

Date of issue: 15 November 2024

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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 Beryl area of Central West New South Wales (NSW) in light of current and projected demand in the Essential Energy distribution network. This Project Specification Consultation Report (PSCR) represents the first step in the RIT-T process.

As set out in our revenue proposal for the current (2023-28) regulatory control period, and most recent (2024) Transmission Annual Planning Report (TAPR),[1] we have identified reactive margin shortfall (and voltage) issues in the Beryl area, arising from current and projected demand in the downstream Essential Energy distribution network.[2]

While load at the Beryl BSP has grown in recent years, to a current winter peak of 82 MW and a summer peak of 77 MW, it is now forecast to remain relatively flat going forward. However, we estimate that based on these demand levels, during a contingent outage of Line 94B (between Beryl and Wellington), the current 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.[3]

While no significant unserved energy has occurred to-date, due to contingent outages not having occurred during these peak periods, our power system studies have identified continuing reactive margin shortfall issues in the Beryl area going forward, if action is not taken, particularly during times where the renewable generation in the area is not being dispatched.

Identified need: compliance with the NER requirements regarding reactive margins

The National Electricity Rules (NER) require 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, 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 (NER, Schedule 5.1.8).

Our planning studies show that there is currently a risk of breaching the NER obligations regarding reactive margin requirements in our network if an outage of Line 94B occurs during peak winter 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 have therefore commenced this RIT-T to assess the options available for meeting our reactive margin requirements to avoid these consequences and continue 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, i.e., Schedule 5.1.8 of the NER.

1 Transgrid, *Transmission Annual Planning Report 2024*, p. 52.
2 Transgrid, *Augex Overview Paper*, 2023-28 Revenue Proposal, 31 January 2022, p. 32.
3 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

While we forecast that there will also be voltage control issues if nothing is done (i.e., breaches of the requirements of Schedule 5.1.4 of the NER), 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.

Four credible options have been identified at this stage of the RIT-T

We have identified four potential credible network options to address the identified need from a technical, commercial, and project delivery perspective.

Table E-1 Summary of the credible network options considered at this stage, $2024/25

Option	Description	Capital cost ($m)	Commissioning
1	Install a 30 MVA synchronous condenser at Beryl	24.1	2027/28
2	Construct and operate a network BESS at Beryl	58.1	2027/28
3	Construct a new line adjacent to existing Line 94B	85.6	2028/29
4	Install a 30 MVA STATCOM at Beryl	23.4	2027/28

All works would be completed in accordance with the relevant standards with minimal modification to the wider transmission assets. Necessary outages of affected line(s) in service would be planned appropriately in order to complete the works with minimal impact on the network.

Non-network solutions may be able to assist with meeting the identified need

We consider that non-network options able to provide dynamic reactive support may be able to assist with meeting the identified need.

At this stage, we consider that possible options could include but are not limited to:

- battery energy storage systems (BESS); and
- generators in the region who are able to provide reactive power support.

Non-network solutions offering a reduction in load (e.g., through demand management or embedded generation), are not considered commercially or technically feasible due to the nature of the identified need and the complexity[4] associated with forecasting trigger conditions in advance of required service activations (which would likely result in material over or under-procurement of services from such providers). As such, the specification for non-network solution providers focuses on the requirements for dynamic reactive support.

The following table summarises the location, size and timing requirements for non-network solutions.

[4] For example, in the case of reactive margin constraints, the required technical characteristics of non-network options depend on: (1) general system demand; and (1) renewable generation and storage in the region.

Table E-2 Summary of the location, size and timing requirements for non-network solutions

From	Size - MVAr (supplying)	Location	Time of day
2025/26	30 MVAr	Beryl 132 kV	Overnight only (Summer & Spring: 6 pm – 6 am) (Winter & Autumn: 5 pm – 7:30 am)

The accompanying Expression of Interest (EOI) specifies the type and form of information we are seeking from proponents in order to have their solutions assessed in the Project Assessment Draft Report (PADR).

We encourage interested parties to contact us (via written submissions or otherwise) regarding the potential for their non-network solution to satisfy, or contribute to satisfying, the identified need outlined above.

The credible options will be assessed against three reasonable scenarios

The credible options will be assessed against three different scenarios as part of the PADR analysis to identify the top ranked credible option in terms of expected net benefits.

Table E-3 Summary of proposed scenarios for the PADR assessment

Variable / Scenario	Central demand scenario	Low demand scenario	High demand scenario
Scenario weighting	1/3	1/3	1/3
Demand scenario	Central demand forecast (POE50)	Low demand forecast (POE90)	High demand forecast (POE10)
Discount rate	7%		
VCR	$39.2/MWh		
Network capital costs	Base estimate		
Operating costs	Base estimate		

We propose to weight the three scenarios equally given there is nothing to suggest an alternate weighting would be more appropriate.

In addition, at this stage, we consider that all categories of market benefit derived from an option affecting the wholesale market may be material for this RIT-T, particularly where a non-network component may form part of the credible options. However, we will reassess this in preparing the PADR and, importantly, in light of submissions received to the EOI (and this PSCR).

If any expected wholesale electricity market benefits are expected to be materially different between options, we expect to undertake wholesale electricity market modelling to estimate them. However, if this is not the case, then we will likely apply a proportionate approach to estimating these benefits (which may include not estimating them at all where there is a strong case for them not affecting the ranking of the options).

Should any wholesale market modelling be undertaken for the PADR analysis (i.e., full wholesale market modelling, or a proportionate approach), this would also be reflected in the scenario analysis (in a manner such that the scenarios are 'internally consistent' consistent with the AER's RIT-T Guidelines[5]).

Submissions and next steps

We welcome written submissions on materials contained in this PSCR. Submissions are due on 20 February 2025.[6]

Submissions to this PSCR should be emailed to our Regulation team via regulatory.consultation@transgrid.com.au, while responses to the separate EOI regarding non-network solutions should be emailed to our Innovation team via innovation@transgrid.com.au.[7] In the subject field of any PSCR submission or EOI response, please reference 'Complying with reactive margin requirements at Beryl PSCR'.

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.

We intend to produce a PADR that addresses all submissions received as well as responses to the EOI and presents our draft conclusion on the preferred option for this RIT-T. Subject to what is proposed in submissions to this PSCR, we anticipate publication of a PADR by mid-2025.

5 AER, *Regulatory investment test for transmission Application guidelines,* October 2023, p 44.
6 Consultation period is for 12 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.

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Contents

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 Specification Consultation Report (PSCR) represents the first step in the RIT-T process.

As set out in our revenue proposal for the current (2023-28) regulatory control period, and most recent (2024) Transmission Annual Planning Report (TAPR),[8] we have identified reactive margin shortfall issues (as well as voltage constraints) in the Beryl area in light of current and projected demand in the downstream Essential Energy distribution network.[9] 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 a current winter peak of 82 MW and a summer peak of 77 MW, it is now forecast to remain relatively flat going forward. However, we estimate that based on these demand levels 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 complete voltage collapse in the Essential Energy network.[10]

While no significant unserved energy has occurred to-date due to contingent outages not having 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 long-term solution can be put in place following this RIT-T, we have an operational arrangement for shedding load at a confidential mining load, if required.

The National Electricity Rules (NER) requires Transgrid to operate its network to satisfy reactive margin requirements. Specifically, 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 (NER Schedule 5.1.8).

Our planning studies show that the current network will risk not being capable of supplying load in the area without breaching the NER requirements, if action is not taken, going forward. 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, to avoid breaching NER reactive margin requirements and to avoid complete voltage collapse in the local network.

We have therefore commenced this RIT-T to assess the options available for managing reactive margin requirements to avoid these consequences and continue 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, *Transmission Annual Planning Report 2024*, p. 52.
9 Transgrid, *Augex Overview Paper*, 2023-28 Revenue Proposal, 31 January 2022, p. 32.
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

network solution is identified).[11] We note that, while both summer and winter demand forecast for Beryl (provided by Essential Energy), have decreased since submitting our revised regulatory proposal, our latest studies show that the reactive margin shortfall is still forecast to occur at demand levels significantly lower than the 50% probability of exceedance (POE) forecasts.

1.1. Purpose of this report

The purpose of this PSCR[12] is to:

- set out the reasons why we propose that action be undertaken (the 'identified need');
- present the credible options that we currently consider address the identified need;
- outline the technical characteristics that non-network options would need to provide to assist with meeting the identified need for this RIT-T;
- summarise the assumptions proposed to feed into the PADR analysis; and
- allow interested parties to make submissions and provide inputs to the RIT-T assessment.

Together with this document, we have also released an Expression of Interest (EOI) to provide additional detail on the technical requirements for non-network options and seek submissions from proponents of these options.

Overall, this report provides transparency into the planning considerations for investment options to manage reactive margin shortfalls at Beryl. A key purpose of this PSCR, 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 PSCR. Submissions are due on 20 February 2025.[13]

Submissions to this PSCR should be emailed to our Regulation team via regulatory.consultations@transgrid.com.au, while responses to the separate EOI regarding non-network solutions should be emailed to our Innovation team via innovation@transgrid.com.au.[14] In the subject field of any PSCR submission or EOI response, please reference 'Complying with reactive margin requirements at Beryl PSCR'.

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.

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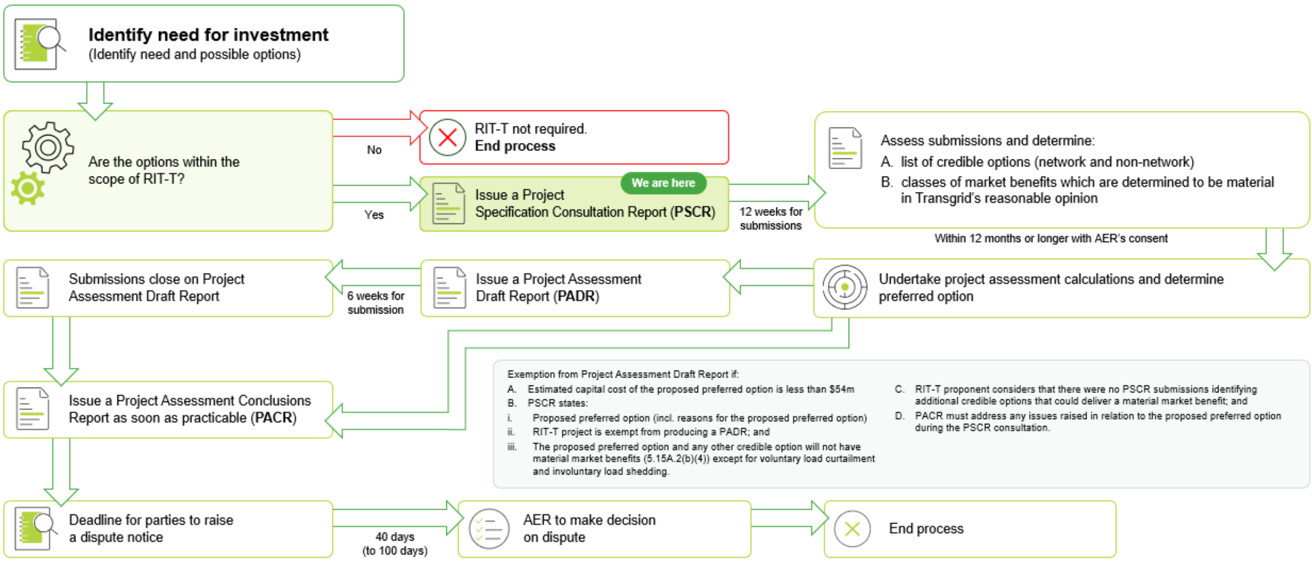
11 AER, *Draft Decision - Transgrid Transmission Determination 2023 to 2028 (1 July 2023 to 30 June 2028) | Attachment 5 Capital expenditure,* September 2022, p.31.
12 See Appendix A for the NER requirements.
13 Consultation period is for 12 weeks. Additional days have been added to cover public holidays.
14 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.

We intend to produce a Project Assessment Draft Report (PADR) that addresses all submissions received as well as responses to the EOI, and presents our draft conclusion on the preferred option for this RIT-T. Subject to what is proposed in submissions to this PSCR, we anticipate publication of a PADR by mid-2025.

Figure 1-1 This PSCR is the first stage of the RIT-T Process[15]



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

2. The identified need

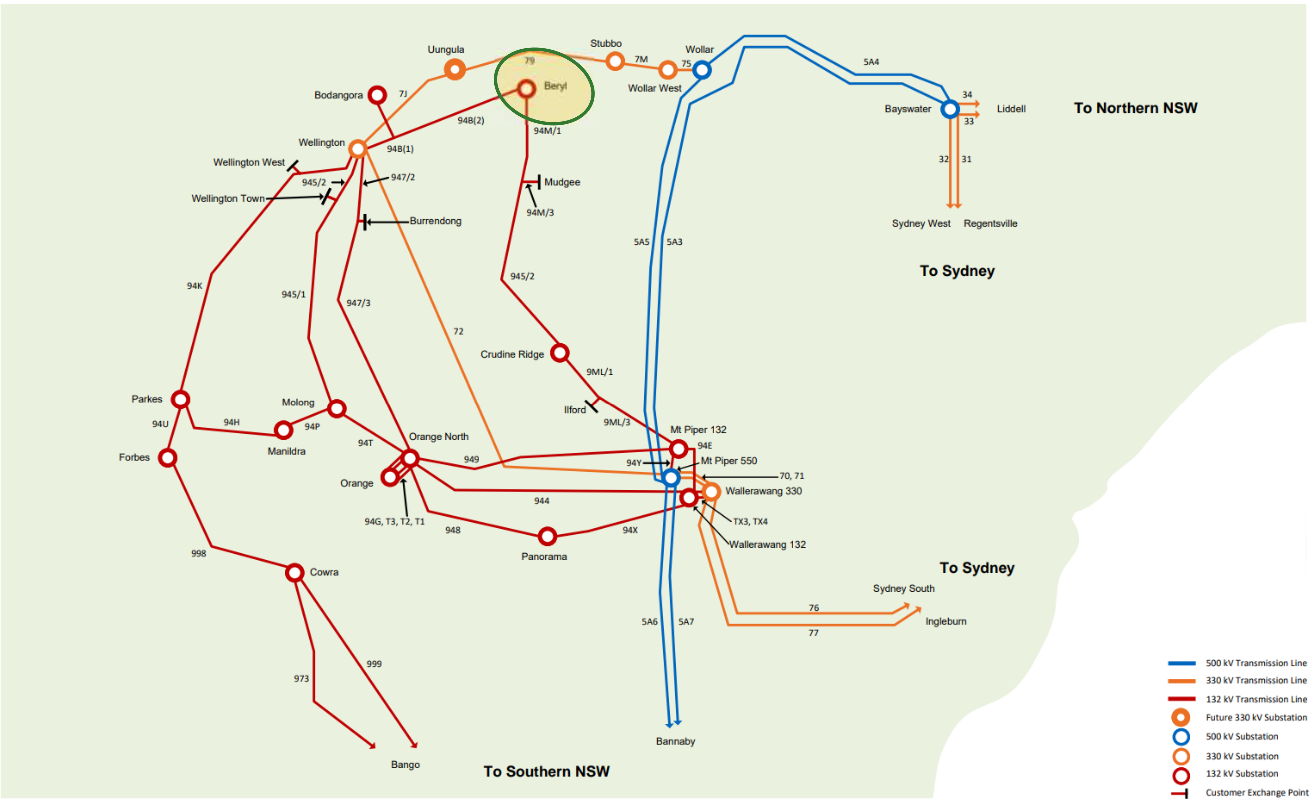
This section outlines the identified need for this RIT-T, as well as the assumptions and data underpinning it. It first sets out relevant background information in relation to the current network and the forecast constraints.

2.1. Background

The Beryl BSP is located in the Central West Orana 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.

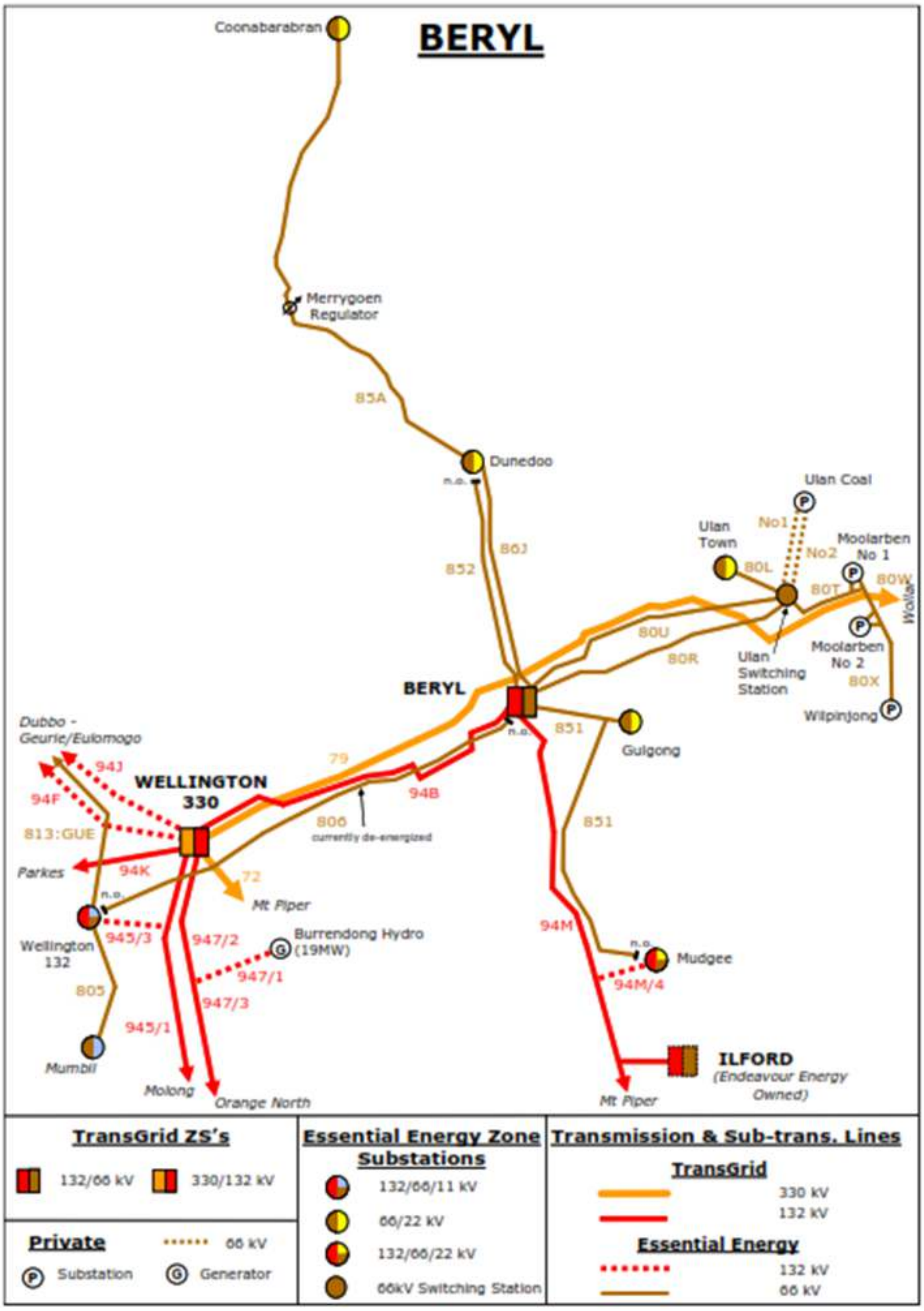
A map showing the location of the Beryl BSP (top left and circled in green), and the surrounding Central West NSW transmission network, is presented below in Figure 2-1.

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 the figure 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. The identified need for that RIT-T is separate to the identified need for this 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 77 MW and 82 MW, respectively. 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).

While load at the Beryl BSP has grown in recent years, it 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 0.1 MW/year over the next 10 years.

We estimate that at current demand levels, during a contingent outage of Line 94B (between Beryl and Wellington), the current 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.[16] 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 not having occurred during these peak periods. Further, to manage the risk before a long-term solution can be put in place following this RIT-T, we have an operational arrangement in place for shedding load at a confidential mining load, if required.

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 proposed 55 MW solar farm near the township of Dunedoo that received development consent from the Department of Planning, Industry and Environment in 2022 (but is yet to be commissioned and connected to Essential Energy's Dunedoo Zone Substation);[17]
- Bellambi Heights Battery Energy Storage System (BESS) – a proposed 354 MW BESS to be built near Gulgong (and connected to the 330 kV network) with a targeted construction date of Q2 2025;[18] and
- Beryl BESS – a 100MW/200MWh BESS near Gulgong proposed to be connected to Beryl substation, construction starting in early 2025 via a direct 132 kV connection.

All three of these potential developments are listed as 'publicly announced' in the latest (July 2024) AEMO 'NEM generation Information' file and are not currently considered by Transgrid to meet the RIT-T criteria for 'committed' or 'anticipated'.

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

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16 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

17 NSW Government Department of Planning, Industry and Environment, *Development Consent* | *Dunedoo Solar Farm*, 2 September 2021.

18 https://www.venaenergy.com.au/all_projects/bellambi-heights-bess/

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, 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 (NER Schedule 5.1.8).

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 occurs during peak winter 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 have therefore commenced this RIT-T to assess the options available for meeting our reactive margin requirements to avoid these consequences and continue 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, i.e., Schedule 5.1.8 of the NER.

While we project that there will also be voltage control issues if nothing is done (i.e., breaches of the requirements of Schedule 5.1.4 of the NER), 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.

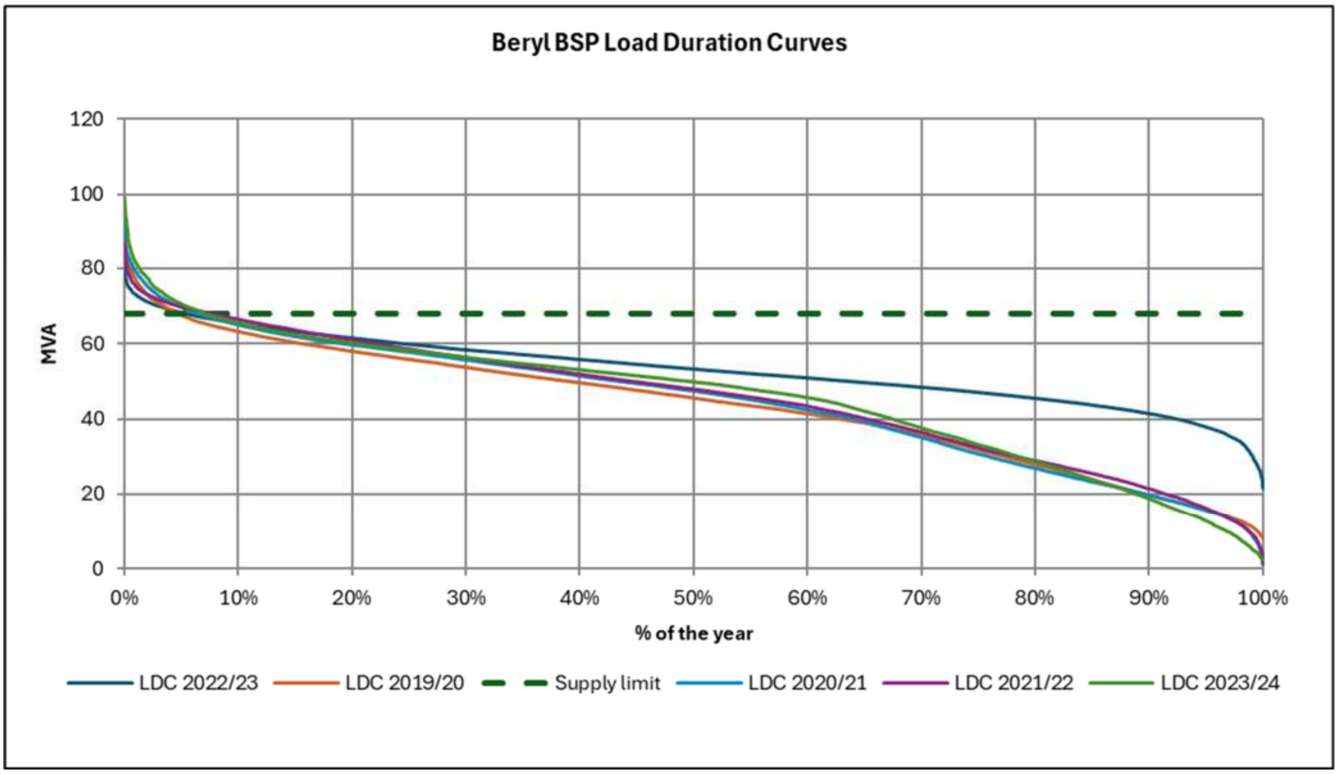
The forecast reactive margin constraints are sensitive to these underlying assumptions.

2.3.1. General load at the Beryl BSP

Forecast maximum summer and winter demand for the Beryl BSP for 2024/25 is between 77 and 82 MW and between 79 and 83 MW, respectively, depending on the demand forecast.

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 2024/25 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., overnight 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	Proposed
Bellambi Heights SF & BESS	330 kV line 79	408 MW/916 MWh	Proposed
Beryl BESS	Beryl 132 kV	100MW/200MWh	Proposed

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 provide reactive power support even during the night time periods (if requested by Transgrid);
- 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);
- 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.

The output of renewable generation in the region directly affects the amount of forecast expected unserved energy and is a variable we expect may be tested as part of the PADR sensitivity testing, to the extent that it is considered material to the choice of preferred option at that stage.

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 fam 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.

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 10.8 MVAr and up to 5.5 MVAr at 66 kV.

3. Potential credible options

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.[19]

At this stage, we have identified four potential credible network options to address the identified need, which are summarised in the table below.

Table 3-1: Summary of the credible network options considered at this stage, $2024/25

Option	Description	Capital cost ($m)	Commissioning
1	Install a 30 MVA synchronous condenser at Beryl	24.2	2027/28
2	Construct and operate a network BESS at Beryl	58.2	2027/28
3	Construct a new line adjacent to existing Line 94B	85.8	2028/29
4	Install a 30 MVA STATCOM at Beryl	23.5	2027/28

While we currently expect that annual operating costs for Options 2-4 can be proxied as 2% of the total capital cost, this will be reviewed as part of the PADR, and more specific estimates may be developed for each asset type. The annual operating cost for Option 1 is estimated at approximately 2.5% of the total capital cost due to marginally higher maintenance requirements for synchronous condensers of this size (but will also be reviewed as part of the PADR).

We also consider that non-network solutions may be able to form credible options for this RIT-T, either as standalone options or in combination with network options (or components of these options). Section 4 and the accompanying EOI provide details on the information that we are seeking proponents of non-network options to provide in order to enable their solution to be considered in this RIT-T.

None of the credible options listed above are expected to have a material inter-regional impact (and nor is this expected from any potential non-network solutions).

The remainder of this section provides more detail on each of the above four potential credible network options, as well as a number of other options considered but not progressed (Section 3.4). First, it presents a description of the 'do nothing' base case against which all credible options are required to be assessed in the PADR (and PACR) analysis under the RIT-T.

All costs presented in this PSCR are in real 2024/25 dollars, unless otherwise stated.

3.1. Base case

Consistent with the RIT-T requirements, the assessment undertaken in the PADR (and PACR) will compare 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.[20]

[19] As per clause 5.15.2(a) of the NER.
[20] AER, *Regulatory investment test for transmission application guidelines – October 2023*, p 22.

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

Under the base case, 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 long-term need. In reality, we are planning to have the most efficient long-term solution on-place (which will be identified through this RIT-T process) to continue to provide reliable supply to the load in question.

3.2. Option 1 – 30 MVA synchronous condenser

Option 1 involves the installation of a new 30 MVA synchronous condenser, connected to the 132 kV busbar at Beryl substation.

The specific scope of this option includes:

- installation of a new 30 MVA 132/11 kV transformer;
- installation of a new 11 kV/415 V auxiliary transformer;
- installation of a new 30 MVA synchronous condenser and associated secondary systems;
- installation of a new control building 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 2024/25 and 2027/28, with the expected commissioning date for this option being 2027/28.

The estimated capital cost of this option is approximately $24.2 million, comprising:[21]

- $1.9 million in labour costs;
- $14.6 million materials costs; and
- $7.7 million in expenses (which includes expenses in relation to contractors, design consultants etc).

The estimated capital cost can be further broken down as follows:

- $2.3 million for the switchyard extension;

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

- $19.4 million for the synchronous condenser; and
- $2.5 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 3-2 shows the expected capital expenditure profile of this option.

Table 3-2: Annual breakdown of Option 1's expected capital cost, $m

	2024/25	2025/26	2026/27	2027/28
Capital expenditure	0.1	1.4	13.8	8.9

3.3. Option 2 – Network BESS

Option 2 involves the construction of a new 18 MW/36MWh BESS at Beryl 132 kV BSP to be operated by Transgrid (i.e., a network BESS).

The specific scope of this option includes:

- extension of existing bus section;
- installation of a new 132 kV transformer and associated switchbay;
- installation of a new BESS secondary system building; and
- associated secondary system equipment.

The scope of works for this option is expected to be carried out between 2024/25 and 2027/28, with the expected commissioning date for this option being 2027/28.

The estimated capital cost of this option is approximately $58.2 million, comprising:

- $3.5 million in labour costs;
- $33.8 million materials costs; and
- $20.9 million in expenses (which includes expenses in relation to contractors, design consultants etc).

The estimated capital cost can be further broken down as follows:

- $3.8 million for the switchyard extension;
- $49.5 million for the BESS; and
- $4.9 million for all other equipment.

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

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

	2024/25	2025/26	2026/27	2027/28
Capital expenditure	0.6	4.8	38.6	14.2

3.4. Option 3 – A new line adjacent to existing Line 94B

Option 3 involves the construction of a new 132 kV line adjacent to Line 94B from Beryl to Wellington (i.e., line duplication) of approximately 51 km in length.

The specific scope of this option includes:

- establishing a new 132 kV bay at the Beryl 132/66 kV substation and a new 132 kV bay at the Wellington 330/132 kV substation; and
- building a new 132 kV single-circuit line, adjacent to Line 94B, between Beryl and Wellington.

These works are expected to be carried out between 2024/25 and 2028/29, for commissioning in 2028/29.

The estimated capital cost of this option is approximately $85.8 million, comprising:

- $6.9 million in labour costs;
- $14.7 million materials costs;
- $52.1 million in expenses (which includes expenses in relation to contractors, design consultants etc); and
- $12.1 million in property costs

The estimated capital cost can be further broken down as follows:

- $70.8 million for the new transmission line;
- $1.4 million for the Wellington substation;
- $1.6 million for the Beryl substation; and
- $12.1 million for property.

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

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

	2024/25	2025/26	2026/27	2027/28	2028/29
Capital expenditure	0.8	2.0	5.6	13.7	63.7

Constructing a new line is expected to have significant environmental and community impact compared to other options (as well as significantly higher property and line easement acquisition risks). We expect to comment further on these as part of the PADR and they may ultimately affect the overall feasibility of this option (and therefore whether it can be considered a credible option).

3.5. Option 4 - STATCOM

Option 4 involves the construction of a new STATCOM at Beryl with a range of +30 MVAr to -5 MVAr. Due to the number of inverter-based connections at Beryl, it is anticipated that a STATCOM with grid-forming inverter technology will be required.

The specific scope of this option includes:

- extension of existing switchyard bench and existing bus section to accommodate new STATCOM 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 2024/25 and 2027/28, with the expected commissioning date for this option being 2027/28.

The estimated capital cost of this option is approximately $23.5 million, comprising:

- $1.9 million in labour costs;
- $13.2 million materials costs; and
- $8.4 million in expenses (which includes expenses in relation to contractors, design consultants etc).

The estimated capital cost can be further broken down as follows:

- $4.5 million for the switchyard extension;
- $16.0 million for the STATCOM; and
- $3.1 million for all other equipment.

Table 3-5 shows the expected expenditure profile of this option.

Table 3-5: Annual breakdown of Option 4's expected capital cost, $m

	2024/25	2025/26	2026/27	2027/28
Capital expenditure	0.4	2.9	19.8	0.4

3.6. Options considered but not progresses

We also considered whether other options could meet the identified need. Reasons these options were not progressed are summarised Table 3-6.

Table 3-6: 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.

3.7. No material inter-network impact is expected

We have considered whether the credible options outlined above are expected to have material inter-regional impacts.22 A 'material inter-network impact' is defined in the NER as:

> *"A material impact on another Transmission Network Service Provider's network, which impact may include (without limitation): (a) the imposition of power transfer constraints within another Transmission Network Service Provider's network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network."*

AEMO's suggested screening test to indicate that a transmission augmentation has no material inter-network impact is that it satisfies the following:[23]

- a decrease in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3% of the maximum transfer capability and 50 MW;
- an increase in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3% of the maximum transfer capability and 50 MW;
- an increase in fault level by less than 10 MVA at any substation in another TNSP's network; and
- the investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

We note that the credible options identified satisfy these conditions and they will only have localised effects around the Central West region of NSW. By reference to AEMO's screening criteria, there is no material inter-network impacts associated with the credible options considered.

[22] As per clause 5.16.4(b)(6)(ii) of the NER.
[23] Inter-Regional Planning Committee. *"Final Determination: Criteria for Assessing Material Inter-Network Impact of Transmission Augmentations."* Melbourne: Australian Energy Market Operator, 2004. Appendix 2 and 3. Accessed 14 May 2020. https://www.aemo.com.au/-/media/Files/PDF/170-0035-pdf

4. Technical characteristics for non-network options

This section describes the technical characteristics that a non-network option would need to deliver to address the identified need.

We consider that non-network solutions that can provide dynamic reactive support may be able to assist with meeting the identified need. At this stage we consider that possible solutions include but are not limited to:

- BESS (owned by a party other than Transgrid); and
- generators in the region who are able to provide reactive power support.

Non-network solutions offering a reduction in load (e.g., through demand management or embedded generation), are not considered commercially or technically feasible due to the nature of the identified need and the complexity[24] associated with forecasting trigger conditions in advance of required service activations (which would likely result in material over or under-procurement of services from such providers). As such, the specification for non-network solution providers focuses on the requirements for dynamic reactive support.

The following table summarises the location, size and timing requirements for non-network solutions.

Table 4-1: Summary of the location, size and timing requirements for non-network solutions

From	Size - MVAr (supplying)	Location	Time of day
2025/26	30 MVAr	Beryl 132 kV	Overnight only (Summer & Spring: 6 pm – 6 am) (Winter & Autumn: 5 pm – 7:30 am)

In practice, dynamic reactive support will be required immediately (contingency or otherwise) when the voltage drops to or below 90% of the normal voltage, which may occur more frequently in operation.

Without fast-acting voltage support in place, a rapid decline in voltage may occur leading to voltage collapse in the area. This dynamic voltage support therefore needs to be available on a 'pre-contingent' basis.

The accompanying EOI specifies the type and form of information that we are seeking proponents of non-network options to provide in order to enable their solution to be considered in this RIT-T.

We encourage interested parties to contact us (via written submissions to the EOI or otherwise) regarding the potential for their non-network solution to satisfy, or contribute to satisfying, the identified need outlined above.

[24] For example, in the case of reactive margin constraints, the required technical characteristics of non-network options depend on: (1) general system demand; and (1) renewable generation and storage in the region.

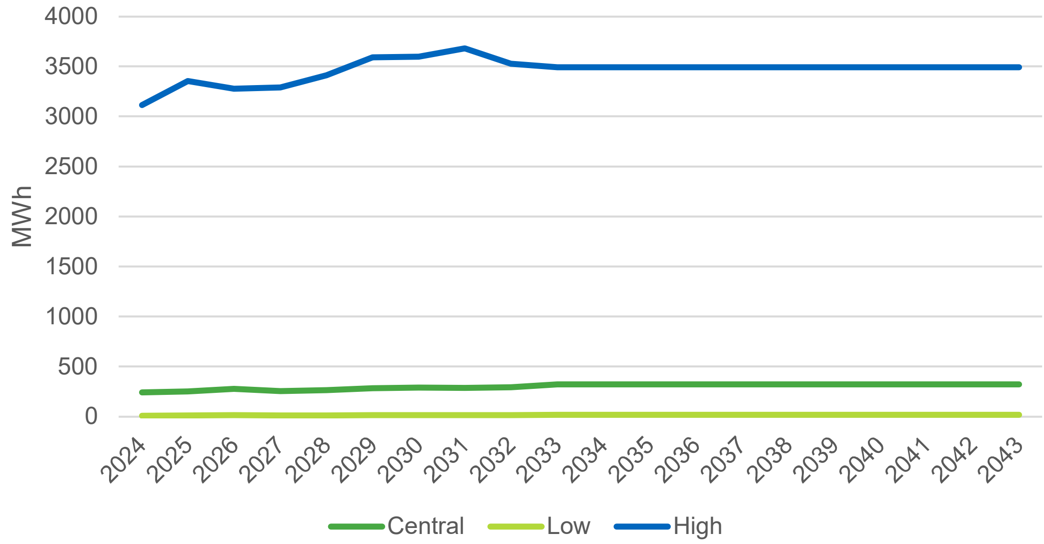
5. Materiality of market benefits

This section outlines the categories of market benefits prescribed in the NER and whether they are considered material for this RIT-T.[25]

5.1. Changes in involuntary load curtailment are expected to be material

We consider that changes in involuntary load shedding are expected to be 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 (which is based on the 10% POE forecasts and results in forecast maximum demand that is approximately 30 MW higher than the reactive margin limit across the period) – as shown in the figure below.

Figure 5-1 EUE forecast under each demand forecast



As part of the PADR assessment, we propose to estimate the value of avoided expected unserved energy under each of the credible options, compared to the base case. This will be valued using Value of Customer Reliability (VCR) for Beryl that is based on the AER's VCR estimates (as outlined in Section 6.4 below).

5.2. Wholesale electricity market benefits may be material

At this stage, we consider that all categories of market benefit derived from an option affecting the wholesale market may be material for this RIT-T. This includes:

- 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;

[25] 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.

- differences in the timing of unrelated network expenditure; and
- changes in network losses.

However, we will reassess the expected materiality of these benefits in preparing the PADR and, importantly, in light of submissions received to the EOI (and this PSCR). Depending on the expected materiality of any expected wholesale electricity market benefits, a proportionate approach may be taken to estimating them (i.e., rather than full wholesale market modelling).

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
Changes in ancillary services costs	While the cost of Frequency Control Ancillary Services (FCAS) may change as a result of changed generation dispatch patterns and changed generation development following any increase to transfer capacity from the options, we consider that changes in FCAS costs are not likely to be materially different between options and are not expected to be material in the selection of the preferred option. FCAS costs are also relatively small compared to total market costs and the market is relatively shallow. There is unlikely to be material changes between portfolio options to the costs of Network Support and Control Ancillary Services (NSCAS), or System Restart Ancillary Services (SRAS) because of the options being considered.
Competition benefits	As the options are not expected to address network constraints between competing generators, and all options are expected to meet the reactive margin requirements equally, competition benefits are not expected to be material for this RIT-T assessment.
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. We also note the AER's view that appropriate identification of credible options and reasonable scenarios captures any option value, thereby meeting the NER requirement to consider option value as a class of market benefit under the RIT-T. At this stage, we do not consider there to be any option value with the options considered in this RIT-T outside of anything captured in the scenario analysis. Additionally, a significant modelling assessment would be required to estimate the option value benefits but it would be disproportionate to potential additional benefits for this RIT-T. We therefore do not propose to estimate option value benefit in addition to any captured in the scenario analysis (i.e., to the extent that the timing or scope of option components, including non-network solutions, varies across the scenarios).

6. Overview of the assessment approach

This section outlines the approach that we are proposing to apply in assessing the net benefits associated with the credible option in the PADR.

6.1. Assessment period and discount rate

A 20-year assessment period, from 2024/25 to 2043/44, is expected to be adopted for this RIT-T analysis. This period takes into account the size, complexity and expected asset life of the assets. However, this assessment period may be updated in the PADR to align with any wholesale electricity market modelling undertaken to estimating the market benefits (as outlined in Section 6.3 below).

Where the capital components have asset lives extending beyond the end of the assessment period, the NPV modelling will include 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. The terminal values will be calculated based on the undepreciated value of capital costs at the end of the analysis period and expected operating and maintenance cost for the remaining asset life.

A real, pre-tax discount rate of 7% will be adopted as the central assumption for the NPV analysis, consistent with AEMO's latest Input Assumptions and Scenarios Report (IASR).[26] The RIT-T 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 will therefore test the sensitivity of the results to a lower bound discount rate equal to the WACC (pre-tax, real) in the latest AER final decision for a transmission business in the NEM as of the date of this analysis. We will also adopt an upper bound discount rate of 10.5% (i.e., the upper bound in the latest IASR).[26]

6.2. Approach to estimating option costs

We have estimated the capital costs based on the scope of works necessary together with costing experience from previous projects of a similar nature.

All 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.
- 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[27]). As part of the annual review, Transgrid benchmarks the outcomes against independent estimates provided by various engineering consultancies.[28]

[26] AEMO, 2023 Inputs, Assumptions and Scenarios Report | Final report, July 2023, p 123.
[27] i.e., there is an equal likelihood of over- or under-spending the estimate total.
[28] 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 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, 2024/25 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. For the option including duplication of Line 94B, a variety of access has been assessed from very light to very heavy depending on the prevailing countryside.

6.3. Wholesale market modelling may be used to estimate market benefits

As outlined in section 5.2, at this stage, we consider that all categories of market benefit derived from an option affecting the wholesale market may be material for this RIT-T, particularly where a non-network component may form part of the potential options. However, we will reassess this in preparing the PADR and, importantly, in light of submissions received to the EOI (and this PSCR).

If any expected wholesale electricity market benefits are expected to be materially different between options, we expect to undertake wholesale electricity market modelling to estimate them. However, if this is not the case, then we will likely apply a proportionate approach to estimating these benefits (which may include not estimating them at all where there is a strong case for them not affecting the ranking of the options).

We note that the Bellambi Heights BESS, Dunedoo Solar Farm and Beryl BESS are all considered ‘proposed’ projects at this stage (i.e., not ‘committed’ or ‘anticipated’ projects). While they are therefore not expected to be included in the base case for the PADR assessment, although this may change if their status changes over the course of this RIT-T.

6.4. Value of customer reliability

We plan to estimate Expected Unserved Energy (EUE) at Beryl under each of the three base cases and for each of the credible options in the PADR assessment.

The avoided EUE for each option will be valued using the estimated VCRs published by the AER.[29] Specifically, we have developed a load-weighted VCR estimate for Beryl of $39.2/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 ($2024/25)

	Residential	Commercial	Mining	VCR
AER VCR estimate[30]	$31.03/kWh	$52.2/kWh	$41.22/kWh	$39.2
Beryl load breakdown	21%	1%	78%	

We will also apply VCR estimates that are 30% lower and 30% higher as part of our sensitivity testing, consistent with the AER's specified +/- 30% confidence interval.[31]

6.5. Three scenarios are proposed to be modelled

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 three scenarios differ by the assumed level of load growth at Beryl, given this is a key assumption that may affect the ranking of credible options against the base case. Specifically, we propose three scenarios for the PADR assessment:

- central demand scenario – to reflect a central estimate of demand (POE50);
- low demand scenario – to reflect a low case estimate of demand (POE90); and
- high demand scenario – to reflect a high case estimate of demand (POE10).

A summary of the key variables in each scenario is provided in the table below.

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 scenario	Central demand forecast (POE50)	Low demand forecast (POE90)	High demand forecast (POE10)
Discount rate	7%		
VCR	$39.2/MWh		

[29] 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 2023.
[30] See AER, Annual update – VCR review final decision – Appendices A to E – December 2023.
[31] AER, Values of Customer Reliability – Final Report on VCR values, December 2019, p. 84.

Variable / Scenario	Central demand scenario	Low demand scenario	High demand scenario
Network capital costs		Base estimate	
Operating and maintenance costs		Base estimate	

We propose to weight the three scenarios equally given there is nothing to suggest an alternate weighting would be more appropriate.

Should any wholesale market modelling be undertaken for the PADR analysis (i.e., full wholesale market modelling, or a proportionate approach), as discussed in section 6.3, this would also be reflected in the scenario analysis (in a manner such that the scenarios are 'internally consistent' consistent with the AER's RIT-T Guidelines[32]).

How the NPV results are affected by changes to other variables (including the discount rate and capital costs) will be investigated via sensitivity analysis in the PADR.

[32] AER, *Regulatory investment test for transmission Application guidelines,* October 2023, p 44.

Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PSCR with the requirements of the National Electricity Rules version 217.

Rules clause	Summary of requirements	Relevant section
5.16.4 (b)	A RIT-T proponent must prepare a PSCR, which must include:	–
	• a description of the identified need;	2.2
	• the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	2.3
	• the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of load reduction of additional supply; (ii) location; and (iii) operating profile;	4
	• if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent ISP;	NA
	• a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alterative transmission options, interconnectors, generation, demand side management, market network services or other network options;	3
	• for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefit are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	3 & 5

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

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

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	6.2
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.	NA
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.	NA