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Maintaining Reliable Supply in the Deniliquin, Coleambally and Finley area

RIT-T Project Assessment Conclusions Report

Region: South West NSW

Date of issue: 24 February 2023

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Executive summary

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining reliable supply in the Deniliquin, Coleambally and Finley area in south west New South Wales (NSW). Publication of this Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process.

The Australian Energy Market Operator (AEMO) forecasts that minimum demand in NSW will rapidly decline over the next 10 years due to ongoing growth in distributed solar (PV) generation.[1] In south west NSW, small to large scale embedded generation connecting to the Essential Energy network is forecast to continue growing, driving declining minimum demand in this region.

The south west NSW region is supplied by four 132 kV transmission lines which form a link between Wagga Wagga and Darlington Point, via Deniliquin, Coleambally, and Finley. Our power system studies show that the declining minimum demand in these areas mean that the electricity transmission system in these areas is at risk of exceeding allowable voltage levels during times of low demand and in particular when nearby solar farms are unable to provide reactive power support.

In addition to the excessive voltage issues we have identified, AEMO have declared an immediate Reliability and Security Ancillary Services (RSAS) gap of 2 MVAr absorbing reactive power in the Coleambally region for overnight when nearby solar farms are not available.[2,3]

We are required to manage the risk of system voltages exceeding their allowable limits as set out in the National Electricity Rules (NER)[4] and procure services to meet the RSAS gap declared by AEMO.[5] This RIT-T therefore examines various network and non-network options to address the excess voltage levels to ensure compliance with the requirements of the NER and provide the greatest net benefit to the market.

Identified need: maintaining reliable supply to the Deniliquin, Coleambally and Finley area in compliance with NER requirements

The identified need for this RIT-T is to maintain reliable supply in the Deniliquin, Coleambally and Finley areas by managing the risk of excess voltage levels due to declining minimum demand. There is an increasing likelihood of unserved energy and non-compliance with the NER without investment to address the need.

We are required to maintain compliance with Schedule 5.1.4 of the NER and meet the RSAS gap declared by AEMO as a result of the declining minimum demand.[6] Consequently, we consider this a 'reliability corrective action' under the RIT-T. A reliability corrective action differs from a 'market benefits'-driven RIT-T in that the preferred option is permitted to have negative net economic benefits on account of it being required to meet an externally imposed obligation on the network business.

1 AEMO, 2021 Electricity Statement of Opportunities, August 2021.
2 AEMO, 2021 System Security Reports, December 2021.
3 AEMO, 2022 Network Support and Control Ancillary Services (NSCAS) Report, December 2022
4 Schedule 5.1.4 of the NER requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage. We expect a non-compliance with this requirement will occur without remedial action.
5 AEMO, 2022 Network Support and Control Ancillary Services (NSCAS) Report, December 2022
6 Schedule 5.1.4 of the NER

No submissions received in response to the Project Specification Consultation Report

We published a Project Specification Consultation Report (PSCR) on 2 June 2022 and invited written submissions on the material presented within the document.

In the PSCR, we noted that non-network options may be able to assist with meeting the identified need, specifically non-network technologies who are able to provide reactive support. At the PSCR stage, we considered that possible solutions included but were not limited to:

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

The PSCR provided details on the technical characteristics that any non-network solutions would need to provide in order to help meet the identified need. Proponents of non-network options were encouraged to make submissions on any non-network option that they believe can address, or contribute to, the identified need.

No submissions were received in response to the PSCR.

No material developments since publication of the PSCR

The following changes have occurred since publication of the PSCR:

- updated capital costs for both options to reflect the latest market rates
- updated market benefits for both options using the latest demand forecasts
- updated commission dates for both options based on the latest delivery program
- updated scenarios and parameters to align with AEMO's 2022 Integrated System Plan (ISP)

These changes have not made an impact on the preferred option. There were no other material changes since publication of the PSCR which affected the ranking of the credible options.

Installation of two 11 MVAr 66 kV reactors at Deniliquin remains the optimal way to maintain reliable supply

We identified two credible network options that meet the identified need from a technical, commercial, and project delivery perspective.[7] These options are summarised in Table E-1: below.

Table E-1: Summary of the credible options

Option	Description	Capital costs ($M 2021-22)	Operating costs ($/year 2021-22)
Option 1	Install two 10 MVAr 132 kV reactors at Deniliquin	9.7	40,000
Option 2	Install two 11 MVAr 66 kV reactors at Deniliquin	8.5	40,000

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

For the purposes of this RIT-T, we only modelled outcomes under the Step Change ISP scenario. This scenario was selected because it is the most likely scenario under AEMO's latest ISP.[8] Adoption of this scenario is also consistent with the minimum demand forecasts provided by Essential Energy, which are POE50 forecasts and therefore represent the most likely forecast. We do not consider it necessary to model outcomes under the other ISP scenarios since the assumptions and parameters underpinning those scenarios will not affect the ranking of the credible options given that each option provides the same level of market benefits.

Based on our analysis, Option 2 delivers the highest net economic benefit while meeting the identified need. This makes Option 2 the preferred option. Since this RIT-T is a reliability corrective action, the top-ranked option is permitted to have a negative market benefit.

Table E-2: Estimated net economic benefit for each option, present value ($M, real 2021-22)

Option	Step Change	Ranking
Option 1	-0.83	2
Option 2	-0.10	1

Sensitivity testing finds that Option 2 continues to deliver higher net economic benefits compared to Option 1, over a range of alternate assumptions regarding key parameters.

Implementing Option 2 by 2025/26 will meet the relevant regulatory obligations set out in the NER and address the RSAS gap declared by AEMO, [9] maintaining reliable supply to the Deniliquin, Coleambally and Finley area in the long term at the lowest cost.

Conclusion: Installation of two 11 MVAr 66 kV reactors at Deniliquin is optimal

This PACR finds that Option 2 (install two 11 MVAr 66 kV reactors at Deniliquin) remains the preferred option at this final stage. This option was found to have the greatest net economic benefit under the Step Change scenario investigated in this PACR, and under a range of sensitivities on key input parameters. Moving forward with this option is the most prudent and economically efficient solution to managing the risk of system voltages exceeding their allowable limits as set out in the NER and to address the RSAS gap identified by AEMO in the long term. [10]

The estimated capital cost of Option 2 is approximately $8.5 million. Routine operating and maintenance cost are estimated at approximately $40,000/annum. The works will be undertaken between 2022/23 and 2025/26. We estimate that Option 2 will be commissioned in 2025/26. All works will be completed in accordance with the relevant standards by 2025/26 with minimal modification to the wider transmission assets. Necessary outages of in-service equipment will be planned appropriately in order to complete the works with minimal impact on the network.

8 In the 2022 ISP, the Step Change scenario is assigned a probability of 50% (See: AEMO, 2022 Integrated System Plan, June 2022, p. 34, https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en)

9 AEMO, 2022 Network Support and Control Ancillary Services (NSCAS) Report, December 2022

10 AEMO, 2022 Network Support and Control Ancillary Services (NSCAS) Report, December 2022

Next steps

This PACR represents the final step of the consultation process in relation to the application of the Regulatory Investment Test for Transmission (RIT-T) process. It follows a Project Specification Consultation Report (PSCR) released in June 2022. No submissions were received in response to the PSCR.

The second step, production of a Project Assessment Draft Report (PADR) was not required for this RIT-T as we consider its investment in relation to the preferred option to be exempt from that part of the process under NER clause 5.16.4(z1). Production of a PADR was not required due to:

- the estimated capital cost of the proposed preferred option being less than $46 million[11];
- the PSCR stating:
  - the proposed preferred option (including reasons for the proposed preferred option)
  - that the RIT-T is exempt from producing a PADR
  - that the proposed preferred option and any other credible option will not have material market benefits[12] except for voluntary load curtailment and involuntary load shedding
- the RIT-T proponent considers that there were no PSCR submissions identifying additional credible options that could deliver a material market benefit; and
- the PACR must address any issues raised in relation to the proposed preferred option during the PSCR consultation.

Further details on the RIT-T can be obtained from our Regulation team via regulatory.consultation@transgrid.com.au. [13] In the subject field, please reference 'Maintaining Reliability in the Deniliquin, Coleambally and Finley area'.

Any party wishing to dispute the conclusions made in this amended PACR must give notice of the dispute in writing, setting out the grounds for the dispute, to the AER and, at the same time, give a copy of the dispute notice to Transgrid. The closing date for this to occur for this PACR is 27 March 2023.[14]

[11] Varied from $43m to $46m based on the AER Final Determination: Cost threshold review November 2021.
[12] As per clause 5.16.1(c)(6)
[13] Transgrid is bound by the Privacy Act 1988 (Cth). In making submissions in response to this consultation process, Transgrid will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions. If you do not wish for your submission to be made public, please clearly specify this at the time of lodgement. See Privacy Notice within the Disclaimer for more details.
[14] NER clause 5.16B(c).

Contents

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1. Introduction

We are applying the Regulatory Investment Test for Transmission (RIT-T) to options which manage excessive voltage levels to maintain reliable supply around Deniliquin, Coleambally and Finley in south west New South Wales (NSW). Publication of this Project Assessment Conclusions Report (PACR) represents the final step in the RIT-T process.

Our power system studies show that declining minimum demand as a result of growth in distributed solar generation in the Deniliquin, Coleambally and Finley areas mean that there is a need to manage the risk of system voltages exceeding their allowable limit. Currently, the excessive voltages are managed through operational measures which reduce supply reliability in the Deniliquin, Coleambally and Finley areas. In addition, in AEMO's 2021 System Security Report, AEMO declared a reliability and security ancillary services (RSAS) gap of 2 MVAr absorbing reactive power in the Coleambally region.[15] This RSAS gap has been reconfirmed in AEMO's 2022 Network Support and Control Ancillary Services (NSCAS) Report.[16]

Schedule 5.1.4 of the National Electricity Rules (NER) requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage.[17] We expect non-compliance with this requirement will occur without remedial action. We have commenced this RIT-T to assess options to ensure this NER requirement continues to be met in the longer term in south west NSW in light of the declining minimum demand, and to address the RSAS gap declared by AEMO in the Coleambally region. 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.

1.1. Purpose of this report

The purpose of this PACR is to:[18]

- identify and confirm the market benefits expected from the various options;
- summarise the submissions received on the PSCR and developments since the PSCR was released and highlight how these have been taken into account in the RIT-T analysis;
- describe the options assessed under this RIT-T, including how these have been shaped as part of the consultation process;
- present the results of the updated NPV analysis for each of the credible options assessed;
- describe the key drivers of these results, and the assessment that has been undertaken to ensure the robustness of the conclusion; and
- identify the overall preferred option under the RIT-T, i.e., the option that is expected to maximise net market benefits.

[15] AEMO, 2021 System Security Reports, December 2021.
[16] AEMO, 2022 Network Support and Control Ancillary Services (NSCAS) Report, December 2022
[17] Schedule 5.1.4 of the NER requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage. We expect a non-compliance with this requirement will occur without remedial action.
[18] See Appendix A for the National Electricity Rules requirements.

1.2. Exemption from producing a Project Assessment Draft Report

This RIT-T is being progressed under the provisions in the NER that allow the assessment to proceed from the initial Project Specification Consultation Report (PSCR) to the final PACR.[19] This investment is eligible for this faster RIT-T process because:

- the estimated capital cost of the preferred option is less than $46 million;[20]
- we identified in the PSCR our proposed preferred option and the reasons for that option, and noted that we will be exempt from publishing the draft report for this preferred option;
- the preferred option and any other credible options in respect of the identified need do not have any material market benefits (with the exception of market benefits arising from changes in voluntary and involuntary load shedding); and
- we did not receive any submissions on the PSCR identifying additional credible options that could deliver a material market benefit.

1.3. Next steps

This PACR represents the final step of the consultation process in relation to the application of the RIT-T to options for maintaining reliability around Deniliquin, Coleambally and Finley. It follows an initial PSCR that was released in June 2022. No submissions were received in response to the PSCR.

Further details on the RIT-T can be obtained from our Regulation team regulatory.consultation@transgrid.com.au.[21] In the subject field, please reference 'Maintaining Reliability in the Deniliquin, Coleambally and Finley area'.

Any party wishing to dispute the conclusions made in this amended PACR must give notice of the dispute in writing, setting out the grounds for the dispute, to the AER and, at the same time, give a copy of the dispute notice to Transgrid. The closing date for this to occur for this PACR is 27 March 2023.[22]

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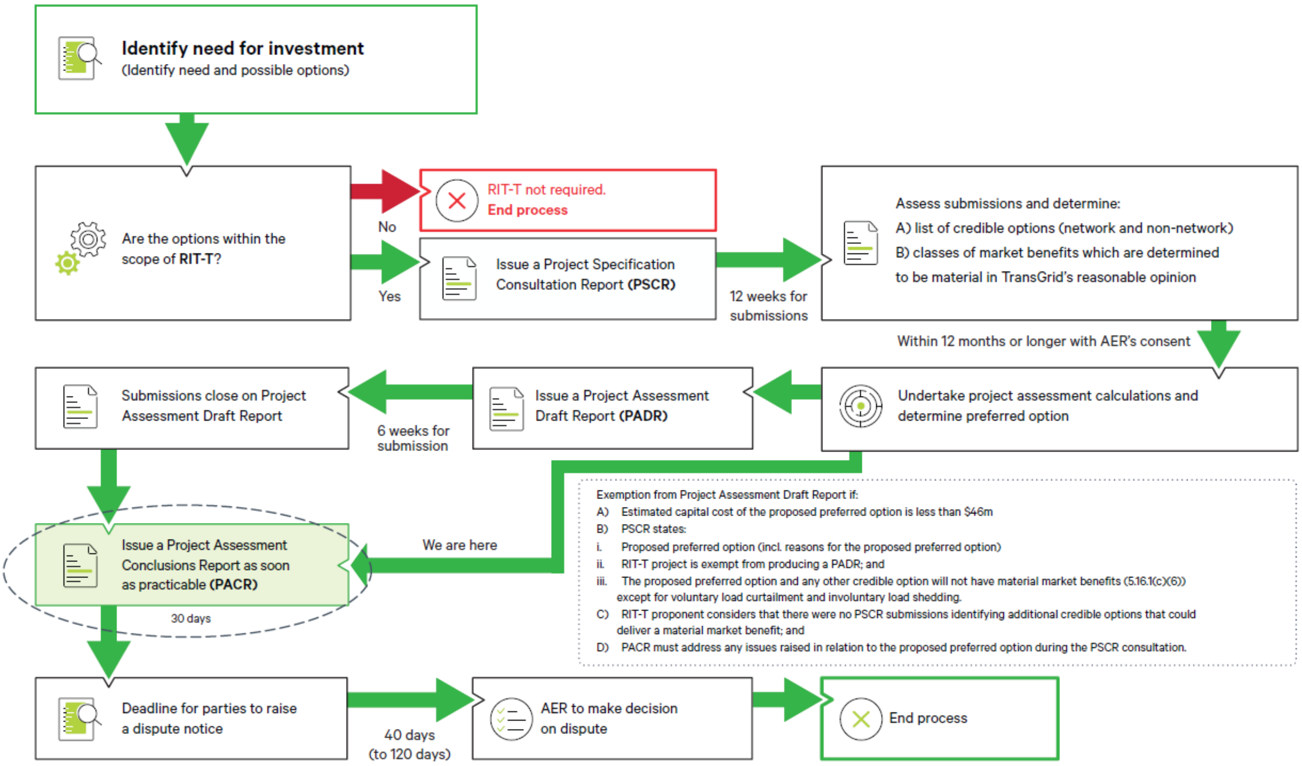
19 Clause 5.16.4(z1)

20 Varied from $43m to $46m based on: AER, Final Determination: Cost threshold review, November 2021.

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

22 NER clause 5.16B(c).

Figure 1-1 This PACR is the final stage of the RIT-T process

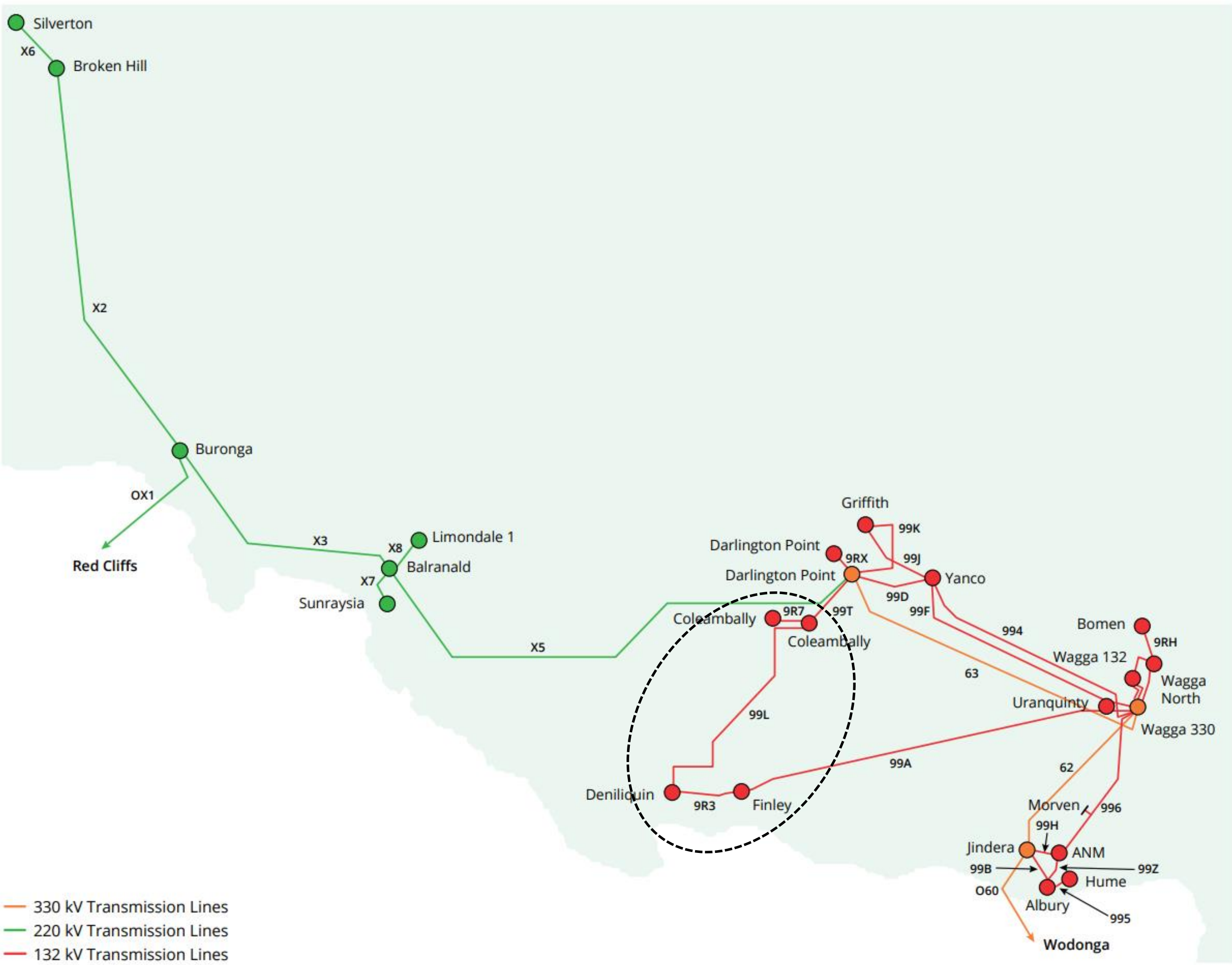


2. The identified need

2.1. Background to the identified need

The current south west NSW electricity transmission network is shown in Figure 2-1. The Deniliquin, Coleambally and Finley areas are supplied by four 132 kV transmission lines which form a link between Wagga Wagga and Darlington Point, via Finley, Deniliquin and Coleambally. These are circled in Figure 2-1 below.

Figure 2-1: South west NSW transmission network



The latest demand forecasts show that minimum demand in NSW is expected to steadily decline over the next 20 years due to continued growth in distributed solar generation capacity.[23] In south west NSW, the expected growth in embedded generation connected to the Essential Energy network is expected to contribute to falling minimum demand in the Deniliquin, Coleambally and Finley areas in the future.

[23] AEMO, Electricity Statement of Opportunities (ESOO) 2022, August 2022

This declining minimum demand is leading to excessive voltage levels, particularly at night when solar farms are unavailable, and demand is low.

2.2. Description of the identified need

Schedule 5.1.4 of the NER requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage.[24] The NER also requires the power system to be operated in a satisfactory operating state, which requires voltages to be maintained within these levels, both in normal operation and following any credible contingency event.[25]

Our power system studies show that the declining minimum demand in south western NSW, specifically in the Deniliquin, Coleambally and Finley areas, means that there is an immediate need to manage the risk of excessive voltage levels leading to non-compliance with the NER under a single credible contingency. In April 2020, there were several events where excessive voltage levels occurred in this area during times of low demand. During these events, operational measures were implemented to manage the voltage levels by splitting the 132kV subsystem. However, these operational measures reduce the reliability of supply in the area by placing load at risk in the event of a contingency.

In addition to the issues we have identified due to the declining minimum demand and increasing uptake of solar and embedded generation, AEMO have also declared a reliability and security ancillary services (RSAS) gap of 2 MVAr absorbing reactive power in the Coleambally region.[26,27] This gap is for managing post-contingent high voltages at Coleambally during overnight low demand when nearby solar generation is out of service. As such, we are required to either procure services or implement a solution to address the RSAS gap.

We have commenced this RIT-T to assess options to ensure the above NER requirements continue to be met in the longer term in south west NSW in light of the declining minimum demand, and to address the RSAS gap declared by AEMO in the Coleambally region. We consider this a ‘reliability corrective action’ under the RIT-T, as the proposed investment is for the purpose of meeting externally-imposed regulatory obligations and service standards, i.e., Schedule 5.1.4 of the NER.[28]

2.3. Assumptions underpinning the identified need

This RIT-T has been initiated in response to declining minimum demand in the Deniliquin, Coleambally and Finley areas. The demand forecasts underpinning the identified need reflect the expected continued growth in embedded and distributed generation which will continue to reduce minimum demand in the region.

We have undertaken planning studies with a number of operating scenarios (day and night times) to assess the impact of the decreasing minimum demand. These studies shows that loss of one of the 132 kV

[24] Schedule 5.1.4 of the NER requires us to plan and design equipment for voltage control to maintain voltage levels within 10 per cent of normal voltage. We expect a non-compliance with this requirement will occur without remedial action.

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

[26] AEMO, 2021 System Security Reports, December 2021

[27] AEMO, 2022 Network Support and Control Ancillary Services (NSCAS) Report, December 2022

[28] Schedule 5.1.4 of the NER

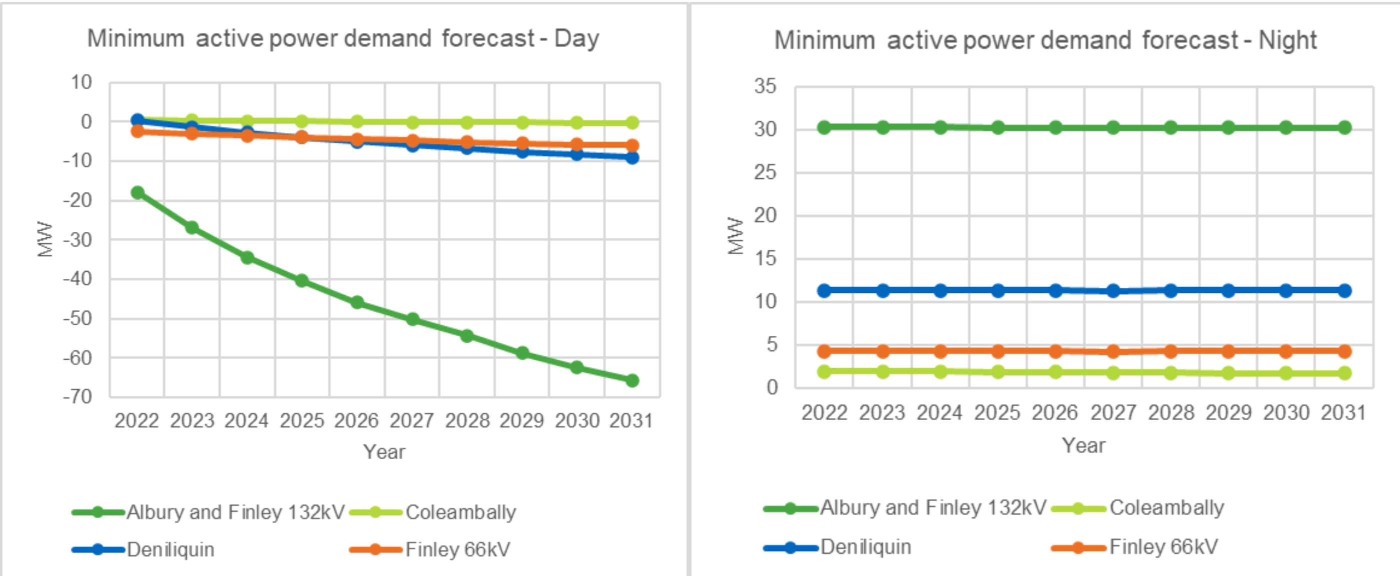
lines – that is, line 99T (Darlington Point to Coleambally), 99A (Deniliquin to Finley) or 99L (Coleambally to Deniliquin) – will result in voltage at one or more of the following busbars exceeding acceptable levels:

- Coleambally 132 kV;
- Deniliquin 132 kV; and
- Finley 132 kV.

Amongst these credible contingencies, the loss of Line 99T is considered to be the critical contingency as it leads to the worst-case results with the highest over voltages at the Coleambally 132kV, Deniliquin 132kV, and Finley 132kV busbars. Following such a contingency event, the corresponding voltage step change exceeds 10%. This is expected to occur during both day time and night time periods when the demand is low and reactive power support is unavailable from the Finley Solar Farm.[29]

Figure 2-2 and Figure 2-3 below illustrates the POE50 minimum active (MW) and reactive (MVAr) power demand forecast at the Coleambally, Deniliquin and Finley 132 kV substations respectively.[30] The demand forecasts show that the day time minimum demand is declining at Finley at a rapid rate compared to the night time minimum demand forecasts. This results in more pronounced over voltages for the day time scenarios under the critical contingency (i.e., a trip of Line 99T) when reactive support is not available from the nearby solar farm. Additionally, the capacitive (injecting) reactive power forecast at Deniliquin and Finley contributes to the excessive voltages at these locations.

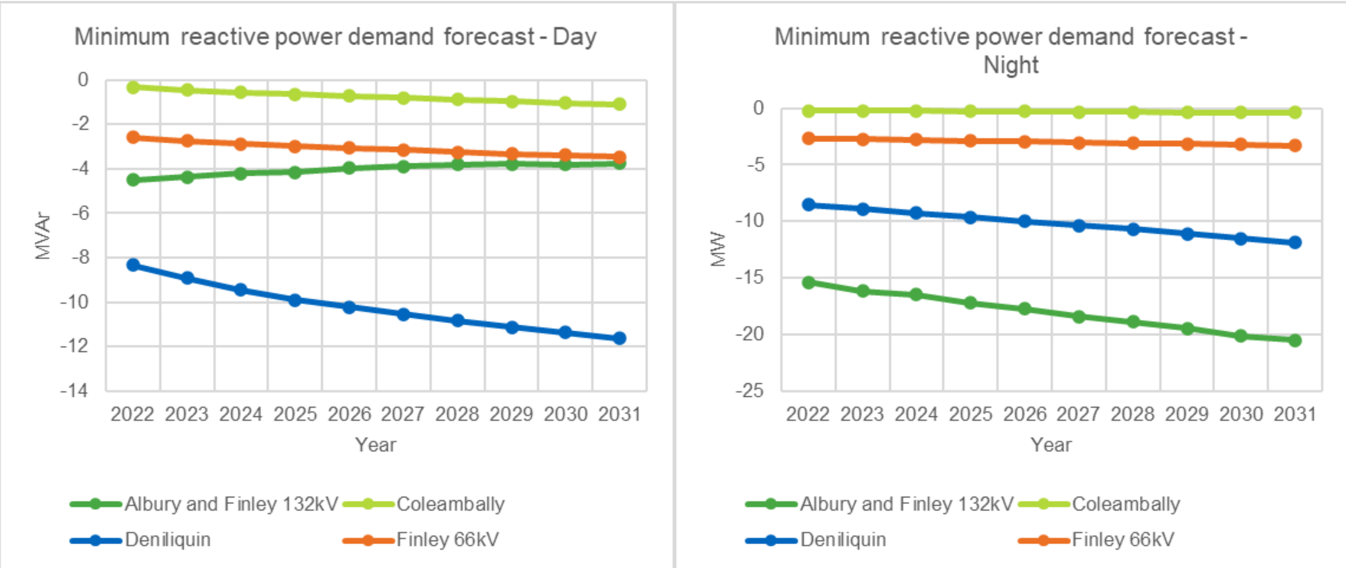
Figure 2-2: Coleambally, Deniliquin and Finley BSP POE50 minimum demand forecasts (Active Power Day/Night)



[29] Day time scenarios with an outage of Finley Solar Farm is the worst case result.

[30] Positive MVAr means Inductive (absorbing) reactive power whereas negative MVAr means Capacitive (injective) reactive power.

Figure 2-3 Coleambally, Deniliquin and Finley BSP POE50 minimum demand forecasts (Reactive Power Day/Night)



The analysis in this PACR uses the central (POE 50) minimum demand forecast provided by Essential Energy. We understand that this forecast is referrable to the 'Step Change' scenario in AEMO's 2022 ISP. Essential Energy has not provided minimum demand forecasts for any other ISP scenario. However, as outlined in section 4.1, each of the credible options avoids exactly the same level of unserved energy and so the underlying demand forecasts are not considered material to the outcome of this RIT-T.

Figure 2-4 shows the voltage at the Coleambally, Deniliquin and Finley 132 kV bulk supply points (BSP) in the event of a contingency event on line 99T using the central minimum demand forecast during the day time. Figure 2-5 shows these same voltages at night time. The figures show that the voltages will exceed or will soon exceed 1.10 pu under a single credible contingency event. The highest over voltages are expected to occur during the day (when reactive power support is not available from the nearby solar farms).

Figure 2-4: Day time post-contingent voltage at Coleambally, Deniliquin and Finley

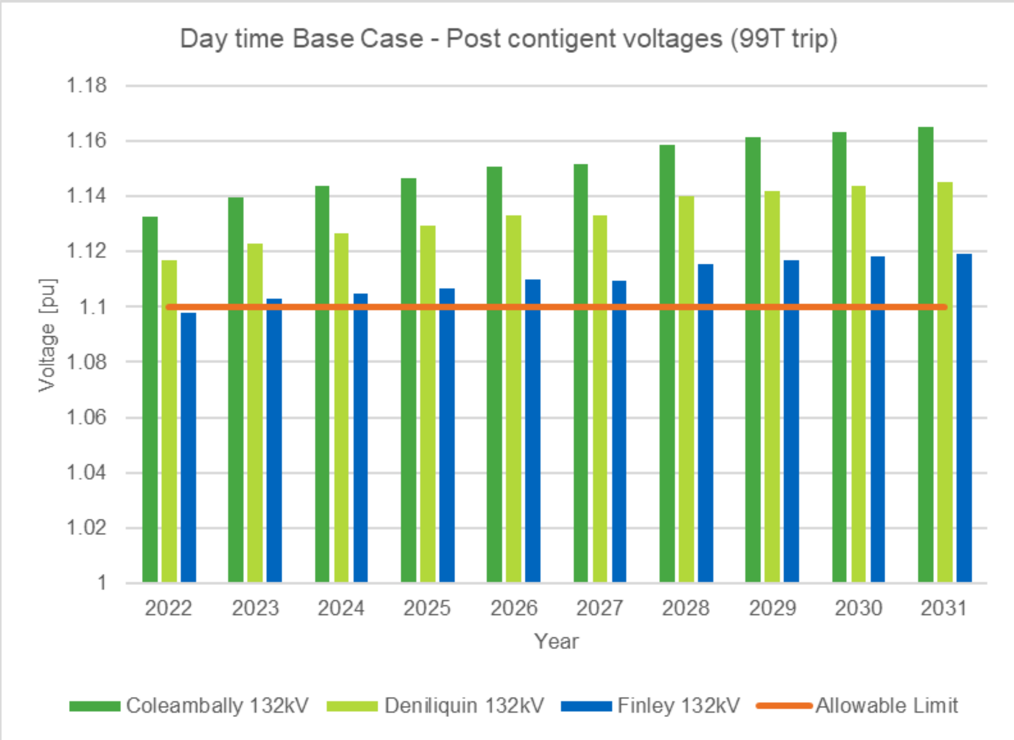
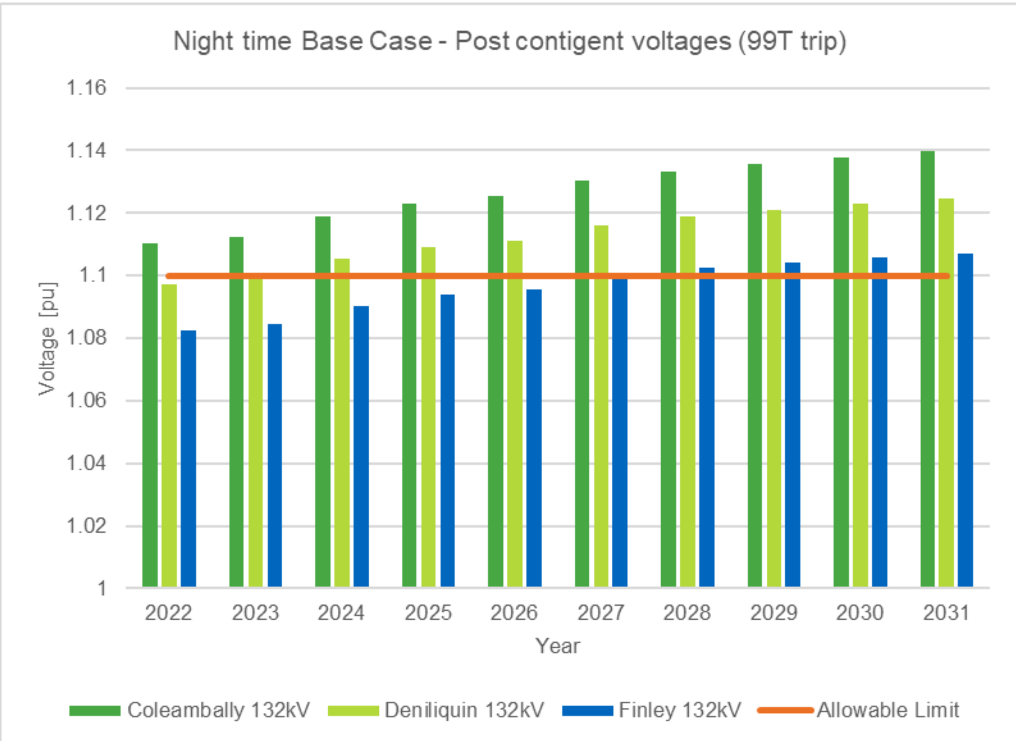


Figure 2-5: Night time post-contingent voltage at Coleambally, Deniliquin and Finley



This assessment highlights that the identified need must be addressed as soon as possible in order to ensure compliance with the NER as well as address the RSAS gap declared by AEMO. In the interim, we have implemented operational measures to manage the voltage levels, although this reduces the reliability of supply to the region.

3. Options that meet the identified need

We considered credible options in this RIT-T assessment as those that would meet the identified need from a technical, commercial, and project delivery perspective.[31] The credible network options for this RIT-T all focus on reactors at Deniliquin substation. The options differ in terms of the busbars that any new reactor connect into and the rating of any new reactor.

Table 3-1 summarises each of the credible options we considered to address the identified need. While the expected timing for all options is shown as later in 2025/26, we are endeavouring to have the preferred option in-place as soon as practical given the immediate need for voltage management in the area. In addition, whilst we considered that non-network solutions may be able to form credible options for this RIT-T, no submissions were received in response to the PSCR.

Table 3-1: Summary of the credible options

Option	Description	Estimated capex ($2021-22)	Expected timing
1	Install two 10 MVAr 132 kV reactors at Deniliquin	$9.7 million	2025/26
2	Install two 11 MVAr 66 kV reactors at Deniliquin	$8.5 million	2025/26

3.1. Base case

Consistent with the RIT-T requirements, the assessment undertaken in this PACR compares the costs and benefits of each option to a base case 'do nothing' option. The base case is the (hypothetical) projected case if no action is taken, ie:[32]

> "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, where excessive voltage levels due to declining minimum demand are unresolved, there is expected to be a reduction in supply reliability in the Coleambally, Deniliquin and Finley areas. This is expected to result in unserved energy of approximately 14 MWh per year until 2045. The RSAS gap declared by AEMO would also not be met.

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

3.2. Option 1 – Install two 10 MVAr 132kV reactors at Deniliquin

Option 1 involves installing two 10 MVAr 132kV reactors at the existing Deniliquin 132/66kV substation. The rating of the reactive power is estimated based on the expected over voltages for the day time scenario forecast with outage of the nearby solar farm, hence the reactive power requirement is larger than the RSAS gap declared by AEMO (i.e 2 MVAr).[33]

[31] As per clause 5.15.2(a) of the NER.
[32] AER, *Regulatory Investment Test for Transmission Application Guidelines,* August 2020, p. 21.
[33] AEMO, 2022 Network Support and Control Ancillary Services (NSCAS) Report, December 2022

Two reactors are proposed to ensure that the switching voltage step size is within acceptable limits (<3%). This involves extending the existing switchyard (within the existing property boundary) to accommodate installation of the reactors and their associated switchbays.

The estimated capital cost of Option 1 is approximately $9.70 million as set out in Table 3-2. Routine operating and maintenance cost are estimated at approximately $40,000/annum. Option 1's expected commissioning date is 2025/26.

Table 3-2 Option 1 Capital Cost ($M, real 2021-22)

Capital cost	FY2022-23	FY2023-24	FY2024-25	FY2025-26
Option 1	0.50	0.90	7.90	0.40

This option will manage the excess network voltages in the region at times of low demand and therefore meet the NER compliance requirements as well as resolve the RSAS gap.

3.3. Option 2 – Install two 11 MVAr 66kV reactors as Deniliquin

Option 2 involves installing two 11 MVAr 66kV reactors at the existing Deniliquin 132/66kV substation. The rating of the reactive power is estimated based on the expected over-voltages for the day time scenario forecast with outage of the nearby solar farm, hence the reactive power requirement is larger than the RSAS gap declared by AEMO (i.e 2 MVAr). [34]

Two reactors are proposed to ensure that the switching voltage step size is within acceptable limits (<3%). This involves extending the existing switchyard (within the existing property boundary) to accommodate installation of the reactors and their associated switchbays.

The estimated capital cost of Option 2 is approximately $8.50 million as set out in Table 3-3. Routine operating and maintenance cost are estimated at approximately $40,000/annum. Option 2 is expected to be commissioned by 2025/26.

Table 3-3 Option 2 Capital Cost ($M, real 2021-22)

Capital cost	FY2022-23	FY2023-24	FY2024-25	FY2025-26
Option 2	0.20	1.90	5.80	0.60

This option will manage the excess network voltages in the region at times of low demand and therefore meet the NER compliance requirements as well as resolve the RSAS gap.

3.4. Options considered but not progressed

We have also considered whether other options could meet the identified need. The reasons these options were not progressed are summarised in Table 3-4.

[34] AEMO, 2022 Network Support and Control Ancillary Services (NSCAS) Report, December 2022

Table 3-4: Options considered but not progressed

Option	Reason(s) for not progressing
Install a 16 MVAr reactor at Coleambally 132kV bus	This option is not technically feasible as a reactor installed at Coleambally would not sufficiently improve the voltages at Deniliquin and Finley during a contingent trip of 99T.
Reinstate two decommissioned 3 MVAr 11kV reactors or install two new 4 MVAr 11kV reactors at Deniliquin substation	This option is not technically feasible as the decommissioned reactor ratings are not adequate to alleviate the excess voltage conditions. New reactors are limited by the rating of the transformer tertiary windings and not able to alleviate the excess voltage conditions.
Upgrade the proposed Dinawan 330kV Switching Station to a 330/132kV Substation and build a new 132kV connection from Dinawan to Coleambally	This option is expected to have a significantly higher capital cost due to the need to establish a 132kV busbar at Dinawan and construct a 132kV transmission line. This option is not considered commercially feasible. This option would also take significantly longer to implement, prolonging the existing voltage and RSAS gap issues.

3.5. No material inter-network impact is expected

We have considered whether the credible options listed above is expected to have material inter-regional impact[35]. 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[36]:

- a decrease in power transfer capability between transmission networks or in another TNSP's network of no more than the minimum of 3 per cent 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 per cent 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 consider that each credible option satisfies these conditions as it does not modify any aspect of transmission assets and will only have localised effects around the south west region of NSW. By reference

35 As per clause 5.16.4(b)(6)(ii) of the NER.

36 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 23 June 2021. https://aemo.com.au/-/media/files/electricity/nem/network_connections/transmission-and-distribution/170-0035-pdf.pdf

to AEMO's screening criteria, there is no material inter-network impacts associated with any of the credible options considered.

3.6. Non-network options

As part of this consultation process, we encouraged interested parties to make submissions regarding non-network options that satisfy, or contribute to satisfying, the identified need. In the PSCR, we outlined the technical characteristics required for a non-network option to meet the identified need, and more specifically, to provide reactive support. No submissions were received regarding non-network options throughout the consultation period, and so no non-network options have been considered for this RIT-T.

4. 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.[37]

4.1. Avoided unserved energy has been estimated (but is not considered material)

We have estimated the expected unserved energy if action is not taken to address the identified need. In the base case, involuntary load shedding would be expected to occur following a contingency on line 99T (Darlington Point to Coleambally), 99A (Deniliquin to Finley) or 99L (Coleambally to Deniliquin) resulting in voltage at the Coleambally, Deniliquin and/or Finley 132 kV BSPs exceeding acceptable levels.

Each credible option considered in this RIT-T is expected to avoid all of this expected unserved energy from 2026/27. Given that there is no difference in avoided expected unserved energy across the options, the level of unserved energy does not have any material impact on the identification of the preferred option under the RIT-T.

Other categories of market benefits prescribed in the NER have not been estimated and are not considered material for this RIT-T, as outlined below.

4.2. Wholesale electricity market benefits are not material

The AER has recognised that if the credible options will not have an impact on the wholesale electricity market, then a number of classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated.[38]

The credible options considered in this PACR do not address network constraints between competing generators and so will not have an impact on generation dispatch outcomes and the wholesale electricity market. Therefore, we consider that the following classes of market benefits are not material for this RIT-T assessment:

- changes in fuel consumption arising through different patterns of generation dispatch;
- changes in voluntary load curtailment (since there is no significant impact on pool price);
- changes in costs for parties other than Transgrid (since there is no deferral of generation investment);
- changes in ancillary services costs;
- competition benefits; and
- Renewable Energy Target penalties.

4.3. No other categories of market benefits are material

In addition to the classes of market benefits listed above, NER clause 5.16.1(c)(4) requires us to consider the following classes of market benefits, listed in Table 4-1, arising from each credible option. The same

[37] 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 5.16.1(c)(6). See Appendix A for requirements applicable to this document.

[38] AER, Regulatory Investment Test for Transmission Application Guidelines, August 2020, p. 29.

table sets out the reasons we consider these classes of market benefits to be immaterial for this RIT-T assessment.

Table 4-1: Reasons non-wholesale electricity market benefits categories are considered not material

Market benefits	Reason
Differences in the timing of unrelated network expenditure	The credible options considered are all designed to meet the required reliability requirements and are unlikely to affect decisions to undertake unrelated expenditure in the network. Consequently, material market benefits will neither be gained nor lost due to changes in the timing of expenditure from any of the options considered.
Option value	Given the immediate nature of the identified need, none of the credible options considered possess the flexibility required for there to be any option value.
Changes in network losses	There is not expected to be any material difference in transmission losses between options.

5. Overview of the assessment approach

This section outlines the approach that we have applied in assessing the net benefits associated with each of the credible options against the base case.

5.1. Description of the base case

As outlined in section 3.1, all costs and benefits considered have been measured against a base case where the excessive voltage levels associated with declining minimum demand in the Deniliquin, Coleambally and Finley area remain unresolved and has a resulting reduction in the reliability of supply.

5.2. Assessment period

The RIT-T analysis considers a 20-year assessment period from 2022-23 to 2041-42. A 20-year period reflects the timeframe for which demand forecasts for the area are available. It also takes into account the size, complexity and expected lives of the options and provides a reasonable indication of the costs and benefits over a long outlook period.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life. The terminal values have been 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. As a conservative assumption, we have effectively assumed that there are no additional cost and benefits after the analysis period.

5.3. Discount rate

The discount rate directly affects the trade-off between costs now and benefits in the future. A real, pre-tax discount rate of 5.50 per cent has been adopted for the NPV analysis presented in this PACR, consistent with the assumptions adopted in the 2021 IASR.[39]

5.4. Approach to estimating option costs

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

The cost estimates are developed using our ‘MTWO’ cost estimating system. This system utilises historical average costs, updated by the costs of the most recently implemented project with similar scope. All estimates in MTWO are developed to deliver a ‘P50’ portfolio value for a total program of works (ie, there is an equal likelihood of over- or under-spending the estimate total).[40]

[39] AEMO, 2021 Inputs, Assumptions and Scenarios Report, July 2021.

[40] 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.

We estimate that the actual cost is within +/- 25 per cent of the central capital cost. An accuracy of +/-25 per cent is consistent with industry best practice and aligns with the accuracy range of a 'Class 4' estimate, as defined in the Association for the Cost Engineering classification system.

All cost estimates are prepared in real, 2021-22 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.

Routine operating and maintenance costs are based on works of similar nature.

5.5. Value of customer reliability

We have applied a NSW-wide VCR value based on the estimates developed and consulted on by the AER.[41] As outlined in section 4.1, each option is expected to avoid the same amount of unserved energy and so the value of this is not considered material for this RIT-T, i.e., it does not have any impact on the identification of the preferred option under the RIT-T.

5.6. One scenario has been modelled

The RIT-T must include any of the ISP scenarios from the most recent IASR that are relevant unless:[42]

- the RIT–T proponent demonstrates why it is necessary to vary, omit or add a reasonable scenario to what was in the most recent IASR, and
- the new or varied reasonable scenarios are consistent with the requirements for reasonable scenarios set out in the RIT–T instrument.

The AER's RIT-T Guidelines clarifies that the number and choice of reasonable scenarios must be appropriate to the credible options under consideration, and that the choice of reasonable scenarios must reflect any variables or parameters that are likely to affect the ranking or sign of the net benefit of any credible option.[43]

For the purposes of this RIT-T, we have only modelled outcomes under the Step Change ISP scenario. This scenario was selected because it is the most likely scenario under AEMO's latest ISP.[44] Adoption of this scenario is also consistent with the minimum demand forecasts provided by Essential Energy, which are POE50 forecasts and therefore also represent the most likely forecast.

We do not consider it necessary to model the other ISP scenarios (i.e., Slow Change, Progressive Change, and Hydrogen Superpower scenarios). AEMO has identified that the Slow Change scenario has a very low probability of occurring (approximately 4%). We have excluded this scenario as it does not have a reasonable likelihood of arising. The Progressive Change and Hydrogen Superpower scenarios differ from the Step Change scenario on the basis of a range of parameters, including forecast demand and the approach to decarbonisation. As discussed in section 4.1, the credible options considered in this RIT-T avoid the same amount of unserved energy. This means that the underlying demand forecasts are not

[41] AER, *Values of Customer Reliability, Final report on VCR values*, December 2019. Escalated to December 2021 values.
[42] AER, *Regulatory investment test for transmission*, August 2020, clause 20(b).
[43] AER, *Regulatory investment test for transmission: Application guidelines*, August 2020, p.41.
[44] In the 2022 ISP, the Step Change scenario is assigned a probability of 50% (See: AEMO, 2022 Integrated System Plan, June 2022, p. 34, https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/2022-integrated-system-plan-isp.pdf?la=en)

considered material to the outcome of this RIT-T. We do not consider that other assumptions or parameters underpinning the alternative ISP scenarios will affect the ranking of the credible options.

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

Table 5-1 Summary of the Step Change scenario

Parameter	Step Change
Discount rate	5.50%
Network capital costs	Base estimate
Operating and maintenance costs	Base estimate
Value of Customer Reliability (VCR) ($2021-22)	$46.86/kWh
Minimum demand forecast	Central demand forecast (POE50)

Given that the scenarios considered in this PACR differ from those considered in the PSCR stage, we have recalculated the NPV net economic benefits for this RIT-T under the original set of scenarios and scenario weights (refer to Appendix B). Our findings show that the variation in our scenario analysis was not material to the outcome of this RIT-T.

6. Assessment of credible options

This section outlines the assessment we have undertaken of the credible options. The assessment compares the costs and benefits of the option to the base case. The benefits of each credible option are represented by reduction in costs or risks compared to the base case.

The following changes have occurred since publication of the PSCR:

- updated capital costs for both options to reflect the latest market rates
- updated market benefits for both options using the latest demand forecasts
- updated commission dates for both options based on the latest delivery program
- updated scenarios and parameters to align with AEMO's 2022 Integrated System Plan (ISP)

These changes have not made an impact on the preferred option. There were no other material changes since publication of the PSCR which affected the ranking of the credible options.

6.1. Estimated gross benefits

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case. The only benefit category included in this assessment is avoided involuntary load shedding. The gross benefit is the same for each credible option since, as discussed in section 4.1, the credible options are expected to avoid the same amount of unserved energy.

Table 6-1: NPV of gross economic benefits relative to the base case ($M, real 2021-22)

Option	Step Change
Option 1	5.51
Option 2	5.51

6.2. Estimated costs

The table below summarises the present value of capital costs, and operating and maintenance costs, of each credible option relative to the base case. We consider that Option 2 can be delivered at a lower cost than Option 1 (in NPV terms).

Table 6-2: Costs relative to the base case, PV ($M, real 2021-22)

Option	Step Change
Option 1	8.67
Option 2	7.66

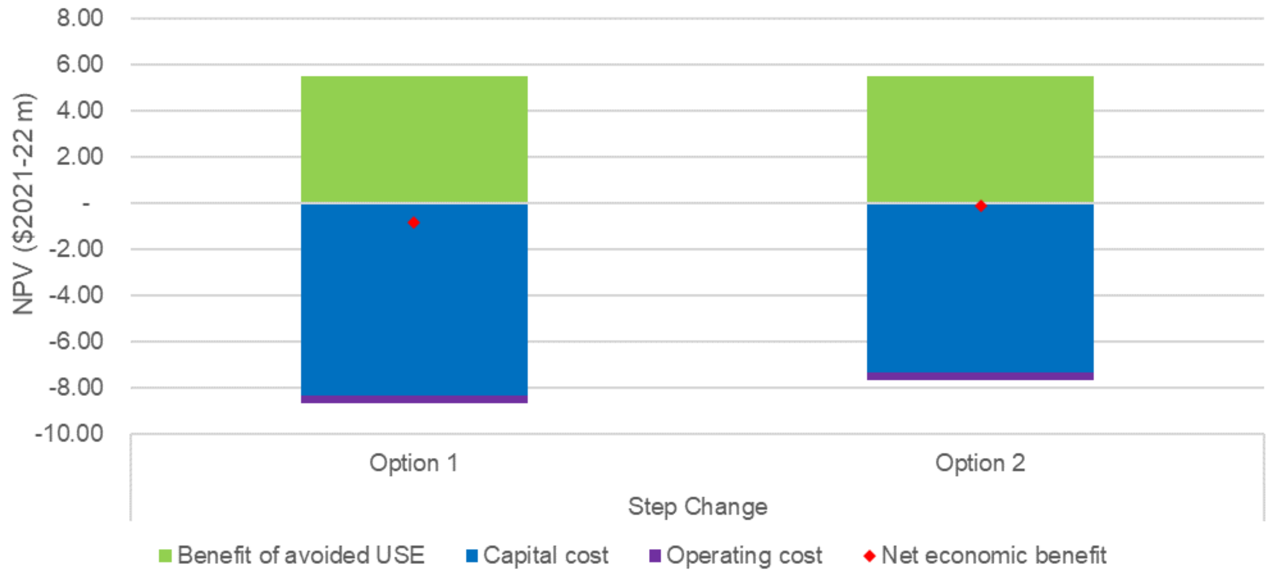
6.3. Estimated net economic benefits

The table below summarises the present value of the net economic benefits for each credible option. The net economic benefits are calculated as the estimated gross benefits less the estimated costs. The results shows that Option 2 has the greatest net market benefit of all the options considered. Since gross benefits are the same across the credible options, the key factor driving this result is that Option 2 can be delivered at a lower estimated cost than Option 1 (in NPV terms). Since this RIT-T is a reliability corrective action, the top-ranked option is permitted to have a negative market benefit.

Table 6-3: Net benefits relative to the base case, PV ($M, real 2021-22)

Option/scenario	Step Change	Ranking
Option 1	-0.83	2
Option 2	-0.10	1

Figure 6-1 Net economic benefits, PV ($M, real 2021-22)



6.4. 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 modelling assumptions. The factors tested as part of the sensitivity analysis in this PACR are:

- Higher or lower VCRs
- Higher or lower network capital costs of the credible options
- Alternate commercial discount rate assumptions

The sensitivity testing was undertaken as against the Step Change scenario. Specifically, we individually varied each factor identified above and estimated the net economic benefit in the scenario relative to the base case while holding all other assumptions under the Step Change scenario constant. The results of the sensitivity tests are set out in the sections below.

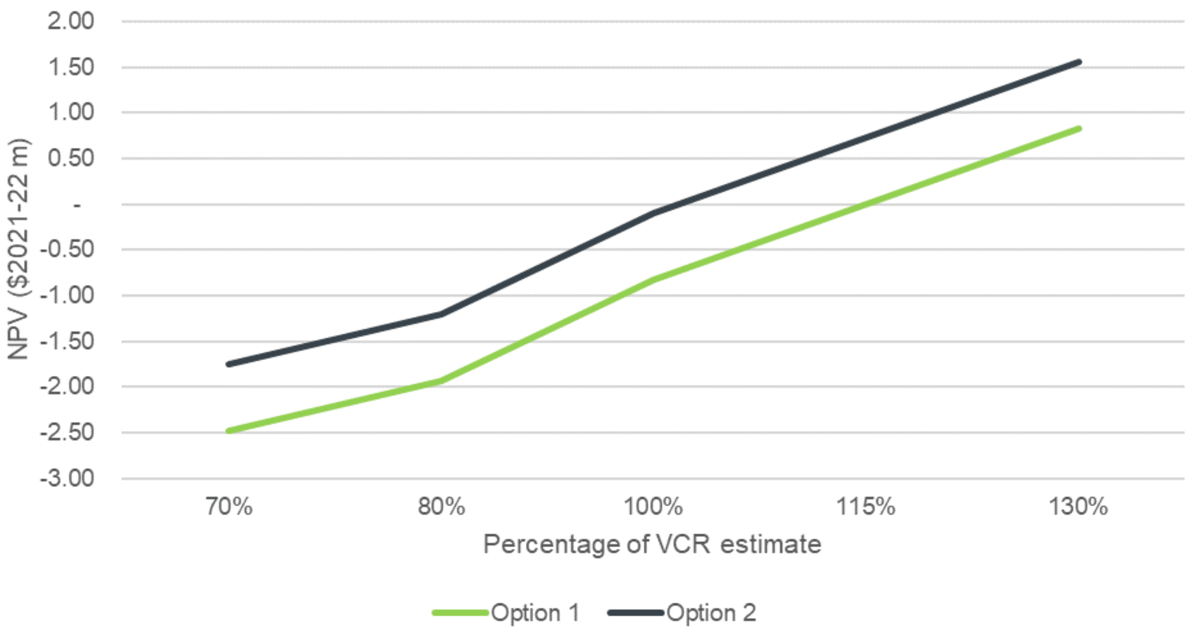
6.4.1. Sensitivity analysis on the VCR

The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting a VCR that is 30% higher (the 'High VCR' scenario) and 30% lower (the 'Low VCR' scenario) than the estimate of VCR adopted in our Step Change scenario. The option ranking for each sensitivity does not change compared to the main results presented above, i.e., Option 2 is always ranked first.

Table 6-4: Net economic benefits relative to the base case under a lower and higher VCR, PV ($M, real 2021-22)

Option/scenario	Low VCR	High VCR	Ranking
Sensitivity	*Step Change estimate - 30%*	*Step Change estimate + 30%*	
Option 1	-2.48	0.82	2
Option 2	-1.75	1.55	1

Figure 6-2 Net economic benefits relative to the base case with lower and higher VCR, PV ($M, real 2021-22)



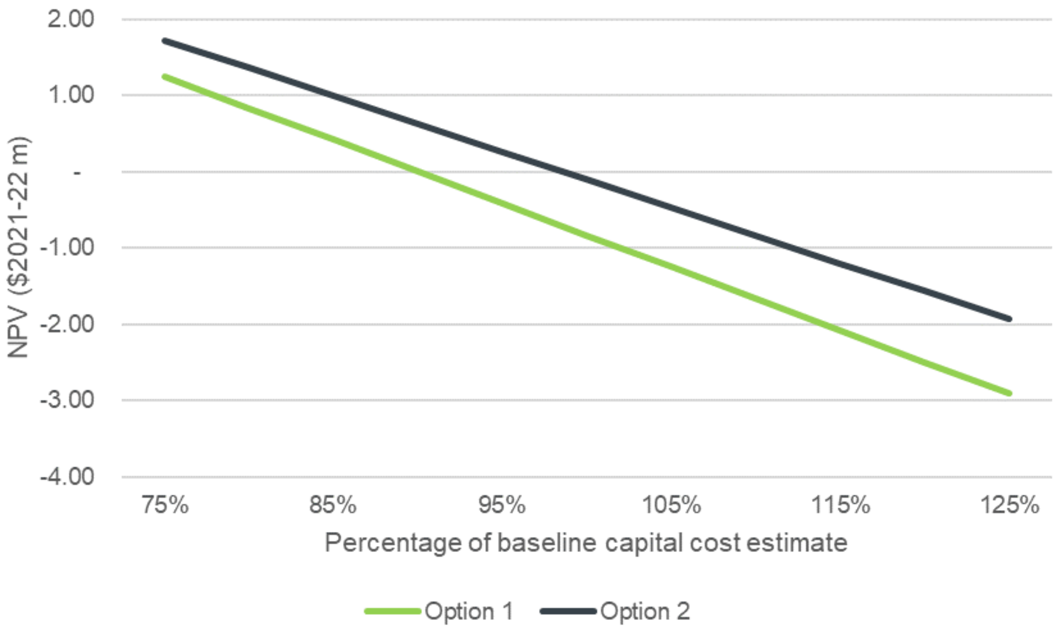
6.4.2. Sensitivity analysis on network capital costs

The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting a capital costs that are 25% higher (the 'High capex' scenario) and 25% lower (the 'Low capex' scenario) than the estimate of capital costs adopted in our Step Change scenario. The option ranking for each sensitivity does not change compared to the main results above, i.e., Option 2 is always ranked first.

Table 6-5: Net economic benefits relative to the base case under a lower and higher capital costs, PV ($M, real 2021-22)

Option/scenario	Low capex	High capex	Ranking
Sensitivity	*Step Change estimate - 25%*	*Step Change estimate + 25%*	
Option 1	1.25	-2.91	2
Option 2	1.73	-1.93	1

Figure 6-3 Net economic benefits relative to the base case with lower and higher capital costs, PV ($M, real 2021-22)



We have also undertaken a threshold analysis to identify whether a change in capital cost estimates would change the RIT-T outcome. Specifically, we considered whether an increase or decrease in the capital costs of one option (while holding the capital costs of the other options constant) would change the RIT-T outcome. Our findings show that Option 2's capex would need to increase by more than 9.95% of its current baseline capex estimates in order to change the RIT-T outcome i.e., for Option 2's NPV net economic benefit to be less than Option 1's. Similarly, we found that Option 1's capex would need to decrease by more than 8.74% in order to change the RIT-T outcome.

6.4.3. Sensitivity analysis on the discount rate

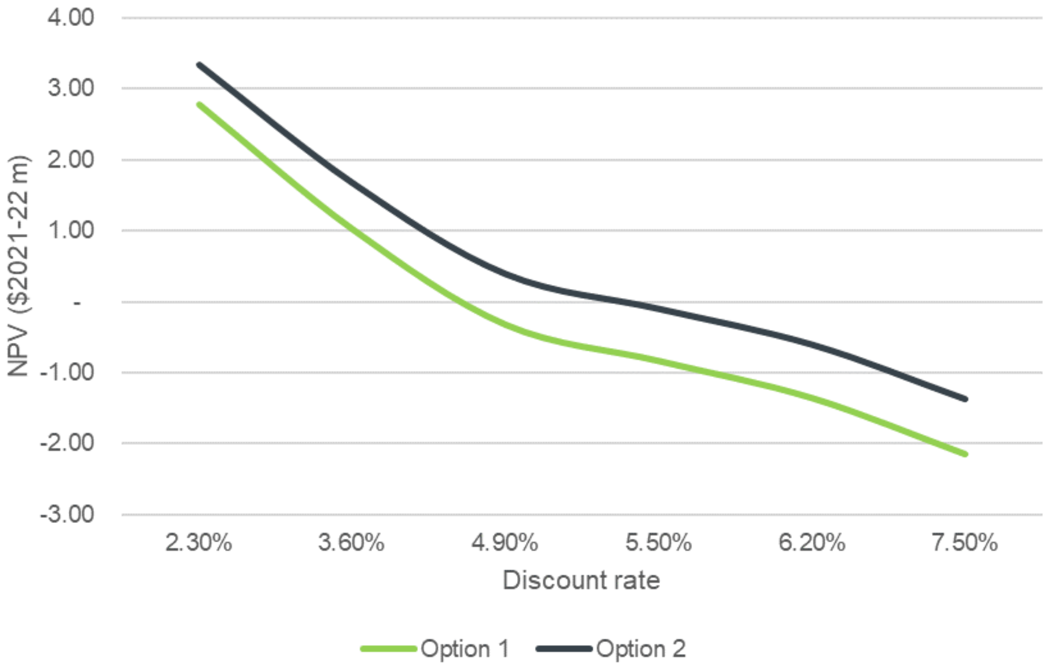
The table and figure below set out the net economic benefits estimated for each credible option relative to the base case by adopting alternative discount rates. Specifically, we considered a low discount rate of 2.3% which is consistent with the AER's latest final determination for a TNSP (the 'Low discount rate' scenario),[45] and a high discount rate of 7.5% which aligns with the high discount rate scenario in the 2022 IASR (the 'High discount rate' scenario).[46] The option ranking for each sensitivity does not change compared to the main results above, i.e., Option 2 is always ranked first.

Table 6-6: Net economic benefits relative to the base case under a lower and higher discount rates, PV $M

Option/scenario	Low discount rate	High discount rate	Ranking
Sensitivity	*2.3%*	*7.5%*	
Option 1	2.77	-2.14	2
Option 2	3.35	-1.38	1

45 The lower bound discount rate is based on the WACC (pre-tax, real) in the most recent final decision for a TNSP revenue determination which was Powerlink in April 2022.
46 AEMO July 2021 2021 Inputs, Assumptions and Scenarios Report

Figure 6-4 Net economic benefits relative to the base case with lower and higher discount rates, PV $M



We have also undertaken a threshold analysis to identify whether a change in the discount rate would change the RIT-T outcome. Our approach involved solving for the discount rate that would result Option 2 not being the preferred option. Our results suggest that there is no reasonable discount rate that would change the RIT-T outcome.

7. Final conclusion on the preferred option

This PACR finds that Option 2 remains the preferred option at this final stage. Option 2 involves installing two new 11 MVAr reactors at Deniliquin to the 66kV busbar.

Option 2 will maintain the reliability of supply to the Deniliquin, Coleambally and Finley area in the long term by managing the risk of system voltages exceeding their allowable limits as set out in the NER and to address the RSAS gap identified by AEMO.

The estimated capital cost of Option 2 is approximately $8.5 million. Routine operating and maintenance cost are estimated at approximately $40,000/annum. The works will be undertaken between 2022/23 and 2025/26. We estimate that Option 2 will commission in 2025/26.

Option 2 is the preferred option in accordance with Schedule 5.16.1(b) of the NER because it is the credible option that maximises the net present value of the net economic benefit and addresses the RSAS gap declared by AEMO as a result of the declining minimum demand. We consider that the analysis undertaken and the identification of Option 2 as the preferred option satisfies the RIT-T.

Appendix A Compliance checklist

This appendix sets out a checklist which demonstrates the compliance of this PACR with the requirements of the National Electricity Rules version 194.

Rules clause	Summary of requirements	Relevant section(s) in the PACR
5.16.4(v)	The project assessment conclusions report must set out:	-
	(1) the matters detailed in the project assessment draft report as required under paragraph (k)	See below.
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought	NA
5.16.4(k)	The project assessment draft report must include:	-
	(1) a description of each credible option assessed;	3
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	NA
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	3, 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;	4
	(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);	3,4
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	6
	(8) the identification of the proposed preferred option;	7
	(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.	3, 7

Appendix B Results under the original scenarios

We have updated the scenarios in this PACR to better align with the RIT-T, the AER's RIT-T Guidelines, and the AER's recent decision with respect to the North West Slopes and Bathurst, Orange and Parkes RIT-T.[47] As a result, the scenarios presented in this PACR are different to the scenarios that were adopted in the PSCR. For clarity, the PSCR scenarios are set out in the table below.

Table 7-1 Summary of PSCR scenarios

Variable / Scenario	Central	Low benefit scenario	High benefit scenario
Scenario weighting	*50%*	*25%*	*25%*
Discount rate	5.50%	7.50%	2.30%
Network capital costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Operating and maintenance costs	Base estimate	Base estimate + 25%	Base estimate - 25%
Value of Customer Reliability (VCR)	$46.86/kWh	$46.86/kWh	$46.86/kWh
Minimum demand forecast	POE50	POE50	POE50

In addition to updating the scenario parameters, the following changes have also occurred since the PSCR:

- updated capital costs for both options
- updated market benefits (i.e., avoided lost load) for both options
- updated commission dates for both options

We have remodelled the NPV calculations using this updated data under the scenarios that were adopted in the PSCR. The results of this analysis, which are summarised below, show that the change in scenario parameters is not material to the outcome of this RIT-T, i.e., Option 2 continues to be the preferred option in addressing the identified need.

Estimated gross benefits under the PSCR scenarios

The table below summarises the present value of the gross benefit estimates for each credible option relative to the base case. The results have been presented separately for each PSCR scenario, and on a weighted basis. The benefits included in this assessment are avoided involuntary load shedding.

Table 7-2: NPV of gross economic benefits relative to the base case under the PSCR scenarios ($2021/22 m)

Option/scenario	Central	Low benefit	High benefit	Weighted
Scenario weighting	50%	25%	25%	
Option 1	5.51	4.46	7.89	5.51
Option 2	5.51	4.46	7.89	5.51

[47] See: AER, *Decision: North West Slopes and Bathurst, Orange and Parkes Determination on dispute - Application of the regulatory investment test for transmission*, November 2022 (https://www.aer.gov.au/system/files/AER%20-%20Determination%20on%20RIT-T%20dispute%20-%20Transgrid%20-%20BOP%20and%20NWS%20disputes_0.pdf)

Estimated costs under the PSCR scenarios

The table below summarises the present value of capital costs, and operating and maintenance costs, of each credible option relative to the base case. The results have been presented separately for each PSCR scenario, and on a weighted basis.

Table 7-3: NPV of capital and operating costs relative to the base case under the PSCR scenarios ($2021/22 m)

Option/scenario	Central	Low benefit	High benefit	Weighted
Scenario weighting	50%	25%	25%	
Option 1	8.67	10.22	7.18	8.67
Option 2	7.66	9.03	6.35	7.66

Estimated net economic benefits under the PSCR scenarios

The net economic benefits calculated as the estimated gross benefits less the estimated costs. The table below summarises the present value of the net economic benefits for each credible option relative to the base case. The results have been presented separately for each PSCR scenario, and on a weighted basis. The table shows that Option 2 has the greatest net market benefits of all the options considered. Since this RIT-T is a reliability corrective action, the top-ranked option is permitted to have a negative market benefit.

Table 7-4: NPV of net economic benefits relative to the base case under the PSCR scenarios ($2021/22 m)

Option/scenario	Central	Low benefit	High benefit	Weighted	Ranking
Scenario weighting	50%	25%	25%		
Option 1	-0.83	-3.52	3.32	-0.83	2
Option 2	-0.10	-2.60	3.84	-0.10	1

Figure 7-1 NPV of net economic benefits relative to the base case under the PSCR scenarios ($2021/22 m)