SA Transmission Network Voltage Control

RIT-T Project Assessment Draft Report

DECEMBER 2023

ElectraNet

Company Information

ElectraNet Pty Ltd (ElectraNet) is the principal electricity transmission network service provider (TNSP) in South Australia.

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Executive Summary

South Australia remains at the forefront of the global energy transformation. This is bringing with it a range of challenges as renewable energy sources such as solar, wind, storage and consumer energy resources in homes and businesses continue to displace traditional generation and drive two-way power flows on the transmission network.

One such challenge faced by ElectraNet is ensuring sufficient static and dynamic voltage control capability within South Australia. Schedules 5.1a.4, 5.1.4 and 5.1.8 of the National Electricity Rules (NER) set out various voltage control requirements that ElectraNet is required to comply with. ElectraNet's modelling indicates that, beyond 2024-25, the allowable limits in the NER will be exceeded for credible contingencies.

Specifically, there is a reactive power shortfall of 125 MVAr in the metropolitan region and 50 MVAr in the South East region.[1]

On 1 December 2023 AEMO declared a Network Support and Control Ancillary Service (NSCAS) shortfall in South Australia for voltage control. [2]

ElectraNet is applying the Regulatory Investment Test for Transmission (RIT-T) to options for ensuring sufficient voltage control in the South Australian region of the National Electricity Market (NEM) including closing AEMO's declared shortfall of NSCAS in South Australia. The identified need for this RIT-T is reliability corrective action since investment is required to meet a regulatory obligation.

This Project Assessment Draft Report (PADR) represents the second stage of the formal RIT-T process and follows publication of the Project Specification Consultation Report (PSCR) in December 2022.

Three options have been identified to address the identified need. Each would increase the amount of reactive power in the Adelaide metropolitan and South East regions. These options are:

- **Option 1 – transmission connected 275kV reactors**, which comprises the installation of five 60 MVAr switched 275kV reactors in the Adelaide metropolitan region and one 50 MVAr switched 275kV reactor on the transfer corridor between the South East and Adelaide;
- **Option 2 – transmission connected 275kV dynamic reactive devices**, which comprises the installation of four 275kV connected SVC (or similar) with at least 60 MVAr reactive absorb range each in the Adelaide metropolitan region and a 50 MVAr switched 275kV reactor on the transfer corridor between South East and Adelaide.
- **Option 4[3] – hybrid Battery Energy Storage System (BESS) and network option,[4]** which comprises a combination of BESS (as proposed in submissions to the PSCR) which can displace one or more elements of either Option 1 or Option 2, together with the remaining network elements of those options.

1 These shortfall quantities refer to 125 MVAr as measured at Para and to 50 MVAr as measured at the South East 275kV substation. This aligns with the discussion in the PSCR, which referred to between 200 and 400 MVAr as measured at various locations on the network.

2 AEMO, 2023 Network Support and Control Ancillary Services (NSCAS) Report, December 2023

3 This option has been named 'Option 4' for consistency with the earlier PSCR which identified distribution connected reactive plant as 'Option 3'. Option 3 is no longer considered to be a credible option for this RIT-T because SA Power Networks has advised that its resourcing for reactor installations is highly constrained beyond its own current power factor compliance program in the 2025-30 period.

4 Option 4 represents multiple potential options as it could consist of various combinations of BESS, reactors and/ or SVCs.

Each option includes implementing automatic control schemes for transmission-connected reactive plant and automation of on-load tap changers across the network.

ElectraNet's analysis, which is summarised in Table E 1, shows that Option 1 has the greatest net benefit. The analysis adopts a 20-year assessment period and draws on the central discount rate in AEMO's 2023 Inputs, Assumptions and Scenarios Report (IASR).

While net benefits are negative, this is acceptable under the RIT-T because the identified need is a reliability corrective action.[5] Sensitivity analysis with respect to capital costs and alternate commercial discount rate assumptions further support Option 1 as the preferred option.

Table ES 1 Net benefits relative to the base case, (PV $m 2023-24)

Option	Step change scenario	Ranking
Option 1	-74.3	1
Option 2	-157.5	2
Option 4	Not calculated, but would have a higher net cost	3

ElectraNet's assessment of Option 4 identified that only two of the proposed BESS (BESS A and BESS E) would be capable of providing sufficient MVAr at Para to defer a reactor under Option 1.[6] However, the capital costs of each of these BESS is materially higher than the cost of the reactor it would defer. Further, the additional market benefits associated with either of these BESS are insufficient to offset this capital cost difference. As a result, the hybrid Option 4 is ranked lowest in the RIT-T assessment.

Option 1 is therefore the preferred option under the RIT-T at this draft stage. The estimated capital cost of this option is $85.7 million, with operating costs assumed to be one per cent of capital costs. The option is expected to take one-to-two years to design and construct and be commissioned progressively through to June 2026.

ElectraNet welcomes written submissions on this Project Assessment Draft Report (PADR), which are due on or before 15 February 2024. Submissions are particularly sought on the credible options presented and the assessment of these credible options.

Submissions should be emailed to consultation@electranet.com.au with the subject 'Voltage Control RIT-T PADR submission'. Submissions will be published on the ElectraNet website. If you do not wish your submission to be made public, please clearly specify this at the time of lodging it.

The Project Assessment Conclusions Report as part of this RIT-T is expected to be published by July 2024.

5 Negative net benefits are inevitable in this case because we have not quantified the benefit of meeting the voltage control requirements.

6 ElectraNet's analysis of non-network options has focused on the requirement at Para because none of the proposed non-network options are in the South East region.

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1. Introduction

South Australia remains at the forefront of the global energy transformation. This is bringing with it a range of challenges as renewable energy sources such as solar, wind, storage and consumer energy resources in homes and businesses continue to displace traditional generation and drive two-way power flows across the network.

One such challenge faced by ElectraNet is ensuring sufficient static and dynamic voltage control capability within South Australia. Schedules 5.1a.4, 5.1.4 and 5.1.8 of the National Electricity Rules (NER) set out various voltage control requirements that ElectraNet is required to comply with. ElectraNet's modelling indicates that, beyond 2024-25, the allowable limits in the NER are exceeded for credible contingencies when there are no conventional generators online.

There are several drivers for this forecast shortfall in reactive power management capability, including:

- the need to offset 1,200 MVAr of transmission line charging on the transmission network during low or zero demand conditions caused by distributed solar PV offsetting demand;
- an increasingly frequent need to offset transmission line charging by using the reserve dynamic capability on the network that would ideally be held in reserve to manage credible and non-credible contingency events;
- an emerging trend of connected loads becoming less inductive (to the point of becoming capacitive) across the day – reducing the network's capability to offset line charging;
- an increase in rapid daily fluctuations caused by intermittent wind and solar PV as well as the more predictable forecast daily load profile dominated by distributed solar PV, which requires increased automation of reactive and voltage control plant to manage the consequent voltage changes; and
- forecast closures of metropolitan thermal generators leading to a loss of voltage control capability.

It follows that action is required to meet ElectraNet's regulatory obligations regarding voltage control. Accordingly, ElectraNet is applying the Regulatory Investment Test for Transmission (RIT-T) to options for ensuring sufficient voltage control in the South Australian region of the National Electricity Market (NEM). The identified need for this RIT-T is reliability corrective action since investment is required to meet a regulatory obligation.

1.1. Purpose

This Project Assessment Draft Report (PADR) is the second step in the RIT-T process. It follows the publication of the Project Specification Consultation Report (PSCR) in December 2022.[7] The purpose of this PADR is to:

- summarise the reasons why ElectraNet has determined that investment is necessary, and developments since the PSCR which affect the quantum of voltage support required (i.e., the identified need);
- summarise the consultation processes to date and submissions to the PSCR;
- describe the credible options that ElectraNet considers may address the identified need;

7 https://www.electranet.com.au/wp-content/uploads/ritt/PSCR-EC.11645-Transmission-Network-Voltage-Control.pdf.

- provide a detailed description of the methodologies used in quantifying each class of material market benefit and cost, together with the reasons why ElectraNet has determined that some classes of market benefit are not material for this RIT-T;
- present the NPV economic assessment of each of the credible options, including the assumptions underpinning this analysis;
- identify and provide a detailed description of the credible option that satisfies the RIT-T, and is therefore the preferred option at this draft stage; and
- provide stakeholders with the opportunity to comment on this assessment so that ElectraNet can refine the analysis (if required) as part of the Project Assessment Conclusions Report (PACR), which is the final step in the RIT-T process.

1.2. Submissions and next steps

ElectraNet welcomes written submissions on this PADR, which are due on or before 15 February 2024. Submissions are particularly sought on the credible options presented and the assessment of these credible options.

Submissions should be emailed to consultation@electranet.com.au with the subject ‘Voltage Control RIT-T PADR submission’. Submissions will be published on the ElectraNet website. If you do not wish your submission to be made publicly available, please clearly specify this at the time of lodging your submission.

The PACR as part of this RIT-T is expected to be published by July 2024.

2. The identified need[8]

ElectraNet has an obligation to ensure sufficient static and dynamic voltage control capability within South Australia to meet schedules 5.1a.4, 5.1.4 and 5.1.8 of the NER. The existing approach to managing compliance with voltage control is through static var controllers (SVCs) at the Para and South-East substations. These SVCs can operate within a range between plus or minus 160 MVAr (in other words, between 160 MVAr capacitive and 160 MVAr inductive).

ElectraNet's modelling indicates that it is prudent to ensure that these SVCs operate in the range between zero to 25 MVAr inductive under steady state and normal conditions in which no Torrens Island units are generating. Keeping the SVCs in this range ensures that there is sufficient dynamic reactive power reserve to react to contingencies and disturbances while keeping voltage within the relevant limits. The availability of 'spare' capacity on the SVCs is therefore a key tool for managing voltage variations on the network.

However, voltage control is currently being provided by operating the SVCs outside of their recommended operating range. ElectraNet's modelling indicates that, beyond 2024-25, the allowable limits specified in the NER will be exceeded for credible contingencies when there are no conventional generators online. This is because of:

- the current operating profile of the SVCs outside of their recommended limits;
- the ongoing increases in the use of electronic devices and appliances by customers across the network; and
- falling minimum demand levels due to continued growth in solar PV output.

ElectraNet has therefore identified the need to increase reactive power capability on the network such that it can operate the SVCs at both the Para and South-East substations within the recommended range (i.e., between zero to 25 MVAr inductive) under steady state and system normal conditions. Doing this will ensure power system security and ongoing compliance with the voltage control requirements of the NER.

Modelling completed as part of the development of the PSCR indicated that 250 MVAr inductive capability was required to be added in the Adelaide metro region and 50 MVAr in the South-East, to bring the dynamic reactive devices to within their recommended operating margin.

Since the publication of the PSCR, there have been several developments in the market, namely progress of BESS at Torrens Island, Templers and Blythe West, wind generation at Goyder and AGL's commitment to retire the Torrens Island Power Station. However, these developments have not affected the MVAr requirement ElectraNet needs to meet.

On 1 December 2023 AEMO declared a NSCAS gap for voltage control in South Australia[9].

This declaration is also inclusive of these developments.

The need remains to obtain reactive support equivalent to 125 MVAr[10] at Para and to 50 MVAr at the South East, to comply with schedules 5.1a.4, 5.1.4 and 5.1.8 of the NER.

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8 A detailed discussion of the identified need is contained in section 3 of the PSCR. The discussion of the identified need in this PADR therefore focuses on the aspects of the identified need that affect the economic assessment presented in this document and developments since the PSCR. ElectraNet encourages interested parties to review the material in the PSCR in addition to this section.

9 AEMO, *NSCAS Report*, December 2023

10 This aligns with the earlier statement of 250 MVAr because the higher value reflected the fact that the reactive support would not all be provided at Para.

3. Consultation on the PSCR

The PSCR presented the technical requirements that non-network solutions would have to satisfy to meet the identified need for this RIT-T and invited interested parties to make written submissions.

ElectraNet received six submissions in response to the PSCR. Five of these submissions related to proposed non-network options (NNOs), which all involved the development of BESSs at various locations in ElectraNet's network. The non-network proponents who responded to the PSCR requested confidentiality and so ElectraNet has not reproduced any of their response material in this PADR. The sixth submission related to the supply, installation, and commissioning of two 35 MVAr static synchronous compensators (statcoms). Strictly speaking this is a network option as ElectraNet would ultimately own the proposed statcoms. However, it was proposed through consultation, so it is addressed with the NNOs.

ElectraNet subsequently engaged directly with each potential proponent on their proposals, including through an expression of interest (EOI) process that requested the information necessary for the assessment of these non-network solutions in this PADR. Not all parties that provided responses to the PSCR provided further information as part of the EOI process. Notwithstanding, ElectraNet has included all six non-network options in this PADR (based on generic information where necessary) to ensure a robust assessment of all potential solutions to the identified need.

Table 3.1 provides a high-level summary of the proposed non-network options assessed in this PADR. Given the commercially sensitive nature of the proposals, the analysis presented in tis PADR is necessarily limited. A detailed summary of the analysis of each proposed NNO has been given to its proponent.

Table 3.1 – Summary of non-network options proposed

Non-network option	Estimated Capital Cost ($m)	Size (MVAr)
A_1	470	100
A_2	704	60
B	145	40
C	145	30
D	290	60
E	391	106.7
F [11]	18	2 x 35 MVAr statcoms

* The two BESSs that comprise non-network option A have the same proponent. Both are required to potentially form part of a credible option (based on the assessment in section 5). ElectraNet has therefore presented them as a single option in this table with two components (A_1 and A_2)

Note: The estimated capital cost is based on the relevant assumptions in AEMO's 2023 Input and Assumptions Report (IASR).

11 Technically this is network solution, but it was received from a proponent and is discussed in this section.

4. Options assessed

This section provides a description of the options that ElectraNet has identified to address the identified need. It discusses the network options identified in the PSCR as well as the NNO proposed in submissions to the PSCR.

4.1. Option 1 – Transmission connected 275kV reactors

Option 1 involves the installation of switchable 275kV reactors in the Adelaide and South East regions. Specifically, it comprises installing:

- four 60 MVAr switched 275kV reactors in the Adelaide metropolitan region, Para, Parafield Gardens West, Torrens Island and Magill and a 50 MVAr reactor at Cherry Gardens; and
- one 50 MVAr switched 275kV reactor at South East substation.

This option also includes implementing automatic control schemes for transmission-connected reactive plant and automation of on-load tap changers at 32 connection points.

The number of reactors required in the Adelaide metropolitan region under Option 1 has increased from three in the PSCR to five. This follows additional analysis undertaken by ElectraNet since the PSCR.

The PSCR also excluded the reactor at Cherry Gardens, which ElectraNet has installed to address acute voltage issues for the upcoming 2023/24 summer. This reactor has been included in the scope of Option 1 for this RIT-T and contributes around 18 MVAr at Para.

ElectraNet determined the combination of reactors that contributes the remaining 100 MVAr of reactive capability (as measured as Para) at the lowest cost. This analysis accounts for local conditions at each substation that affect the cost of installing the relevant equipment. Key factors include land availability and the presence of existing control equipment, as well as the substation layout and whether blast walls are required. The analysis also accounts for the electrical location of the reactor in the network because this affects its ability to contribute to the identified need.

Table 4.1 summarises our analysis for the metropolitan region and shows that installing reactors at each of Cherry Gardens, Para, Parafield Gardens West, Torrens Island and Magill[12] represents the least cost transmission-connected solution, considering the above factors.

In the case of the South East, the optimal location for a new reactor is at the South East substation itself.

[12] The Magill location has been selected as its costs on an adjusted cost per MVAr are materially the same as Northfield and Munno Para, and that there are network benefits to locating a reactor at Magill close to the Magill cable allows the reactor to offset a major source of MVAr, at the source.

Table 4.1 - Reactor effectiveness and estimated cost per MVAr – metropolitan substations

Location	Reactor size	Para contribution (both SVCs - %)	Estimated cost ($m)	Incremental MVAr	Adjusted cost per MVAr ($m/MVAr)	Single outage ranking	Cumulative MVAr	Cumulative cost	Rank
Cherry Gardens 275 kV	60	0.363	12.6	21.8	0.58	9.0	21.8	12.6	8
Parafield Gardens West 275 kV	60	0.442	9.6	26.5	0.36	2.0	76.4	34.8	1
Para 275 kV	60	0.469	12.6	28.1	0.45	1.0	76.4	34.8	2
Torrens Island 275 kV	60	0.396	10.7	23.8	0.45	5.0	100.2	45.5	3
Munno Para 275 kV	60	0.433	12.2	26.0	0.47	0.0	126.2	57.7	4
Northfield 275 kV	60	0.396	11.4	23.8	0.48	6.0	124.0	56.9	5
Magill 275 kV	60	0.42	12.5	25.2	0.49	4.0	125.4	57.9	6
Happy Valley 275 kV	60	0.376	11.4	22.6	0.50	7.0	122.8	56.8	7
Morphett Vale East 275 kV	60	0.37	14.3	22.2	0.64	8.0	122.4	59.8	9
East Terrace 275 kV	60	0.42	24.3	25.2	0.97	3.0	125.4	69.8	10

[a] The costs included in this table represent the point estimate within a range.

The estimated capital cost of Option 1 is $85.7 million.

Table 4.2 provides a breakdown of the capital cost of Option 1 into its constituent components, including the commissioning year and class of cost estimate for each component.

Table 4.2 - Breakdown of capital components and capital cost for Option 1

Location	Component	Commissioning (FY)	AACE cost estimate class	Capital expenditure ($m)
Cherry Gardens	50 MVAr reactor	2025	Class 4	12.6
Para	60 MVAr reactor	2025	Class 4	12.6
Parafield Gardens West	60 MVAr reactor	2026	Class 4	9.6
Torrens Island	60 MVAr reactor	2026	Class 4	10.7
Magill	60 MVAr reactor	2025	Class 5	12.5
South East Substation	50 MVAr reactor	2025	Class 4	11.0
Various	Automatic control schemes Voltage control systems On tap changer	2026	Class 4	16.7
Total				**85.7**

Operating costs are expected to be one per cent of capital costs.

The option is expected to take one to two years to design and construct, with commissioning between 2025 and 2026.

4.2. Option 2 – Transmission connected 275kV or 66kV dynamic reactive devices

Option 2 in the PSCR was to address the identified need using SVCs in the Adelaide metropolitan region and a reactor in the South East region.

Specifically, it comprises installing:

- four 275kV connected SVC (or similar) with 60 MVAr reactive absorb range each in the Adelaide metropolitan region; and
- a 50 MVAr switched 275kV reactor at South East substation.

It also includes implementing automatic control schemes for transmission-connected reactive plant and automation of on-load tap changers at 32 connection points[13].

The estimated capital cost of this option is $188.3 million including both the metropolitan and South East regions.

Table 4.3 - Breakdown of capital components and capital cost for Option 2

Location	Component	Commissioning (FY)	AACE cost estimate class	Capital expenditure ($m)
Adelaide metropolitan region including Munno Para	60 MVAr reactor × 4	2027	Class 4	160.6
South East Substation	50 MVAr reactor	2027	Class 4	11.0
Various	Automatic control schemes Voltage control systems On load tap changer	2026	Class 4	16.7
Total				**188.3**

Operating costs are expected to be one per cent of capital costs.

The option is expected to take two or three years to design and construct, with commissioning by late 2027.

4.3. Option 3 – Distribution connected reactors

Option 3 in the PSCR involved installing reactors on the distribution network operated by SA Power Networks (SAPN). In particular, it involved installing eight 30 MVAr switched 66kV connected reactors in the Adelaide metropolitan region and eight 7.5 MVAr 33kV connected reactors in the South East region.

SAPN had previously considered it possible to install reactors in the metropolitan region as a potential distribution option to address the identified need for this RIT-T. However, SAPN has now advised that these reactors will be required to meet its own 66kV power factor/reactive control obligations at its 66kV connection points.

While other sites across the distribution network could be potential locations to install reactors to assist in meeting the identified need, SAPN has advised that, beyond its current power factor compliance program, potential reactor locations will be highly constrained in the 2025-30 period.

It follows that, regardless of the suitability of any site on its network to meet the identified need, SAPN is unable to commit to delivering a distribution solution for this RIT-T in the required timeframe and is not a proponent for this option.

ElectraNet therefore no longer considers this option to be credible and it has not been assessed further.

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13 Reconnection of the 100 MVAr switched capacitor bank at Happy Valley also formed part of this option at the PSCR stage. However, this reconnection is no longer part of this option as no reactor is proposed for Happy Valley, so disconnecting and reconnecting the capacitor bank there will not be necessary.

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4.4. Option 4 – Hybrid BESS and network option

The fourth option is to use a combination of NNO proposed BESS and network investment to address the identified need.

The potential NNO elements considered as part of this option are those proposed in response to the PSCR, summarised earlier in Table 3.1.

Similarly, to the network elements in Options 1 and 2 above, the location of each BESS affects the contribution it can make to the identified need. As with the network elements discussed above, ElectraNet evaluated the effective amount of reactive power support provided by each proposed BESS considering its electrical location.

The approach ElectraNet took to calculating the reactive power absorption capability of each BESS (which is summarised in Appendix D), is the same as that adopted in assessing the capabilities of the network elements for Options 1 and 2. The result is the weights and MVAr contribution columns set out below in Table 4.4.

This table shows that none of the NNO individually, nor all of them combined, can address the identified need entirely. However, the various NNO options are modular. The two network options consist of several similar components, either reactors or SVCs. The BESS could therefore potentially be deployed individually or in combination with other BESS, as part of a hybrid option, where they displace one of more of the elements in the network options.

Table 4.4 - MVAr contributions of the non-network options at Para

Option	Location	Electrical weight (MVAr at Para)	MVAr contribution at Para
A_1	Mobilong 132 kV	0.094	9.4
A_2	Brinkworth 275 kV	0.201	12.1
$A_{combined}$			23.5
B	Para 132 kV	0.468	18.7
C	Mannum 132 kV	0.118	3.5
D	Blyth West 275 kV	0.105	6.3
E	Tungkillo 275 kV	0.332	35.4
F	Bungama 275 kV	0.049	3.4

* The BESS that comprise non-network option A have the same proponent. Both are required to potentially form part of a credible option. ElectraNet has therefore presented them as a single option with two components (A_1 and A_2).

Displacing one of the reactors requires the non-network option to provide reactive power support equal to or more than that reactor. To increase the economic benefit of the hybrid option, the first reactor to be displaced would be that which contributed to the identified need at the highest marginal cost. This is the reactor proposed for the Magill substation, which would provide 25.2 MVAr.[14]

[14] Due to the proposed locations of the non-network solutions, none of them would contribute to the MVAr requirement in the South East region and so none of them have the potential to defer or replace the 50 MVAr reactor on the South East corridor in Option 1.[15] The screening test is set out in Appendix 3 of the Inter-Regional Planning

Therefore, a necessary but not sufficient condition for including a NNO, or group of NNOs, in a hybrid option is that the NNO would provide at least 25.2 MVAr of reactive support at Para.

As Table 4.4 shows, given their location in the network, non-network solutions B, C, D and F do not provide sufficient reactive power support to displace the Magill reactor. As such, they are not considered further in this PADR.

In contrast, BESS E could provide sufficient reactive power support to displace the Magill reactor.

The individual components of BESS A are not able to defer the Magill reactor, but if both parts are considered collectively (i.e., BESS $A_{combined}$) the shortfall is small. On this basis BESS A could displace the Magill reactor

Therefore, BESS $A_{combined}$ and BESS E have been considered in assessing Option 4. The assessment of this option is discussed further in Section 5.

4.5. Material inter-network impact

In accordance with clause 5.16.4(b)(6)(ii) of the NER, ElectraNet has considered whether the credible options above are expected to have a material inter-network impact.

The NER defines a material inter-network impact 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 currently defines the criteria for material inter-network impact.[15] AEMO's suggested screening test to indicate that a transmission augmentation has no material inter-network impact is that it satisfies the following:

- a decrease in power transfer capability between the transmission networks or in another TNSP's network of no more than the minimum of three per cent of the maximum transfer capacity and 50 megawatts;
- an increase in power transfer capability between transmission networks of no more than the minimum of three per cent of the maximum transfer capability and 50 megawatts;
- 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.

The credible options set out in this PADR would not result in a material change in power transfer capability between South Australia and neighbouring transmission networks because they do not address network constraints between competing generating centres.

Fault levels are not expected to be impacted at any substation in another TNSP's network and the credible options do not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

Committee's Final Determination: Criteria for Assessing Material Inter Network Impact of Transmission Augmentations, Version 1.3, October 2004.

[15] The screening test is set out in Appendix 3 of the Inter-Regional Planning Committee's Final Determination: Criteria for Assessing Material Inter Network Impact of Transmission Augmentations, Version 1.3, October 2004.

AEMO's screening criteria therefore indicate that there is no material inter-network impact associated with the credible options included in this PADR.

5. Materiality of market benefits

The NER require that all categories of market benefit identified under the RIT-T be quantified unless the TNSP can demonstrate that a specific category of market benefit is unlikely to be material to the option rankings.[16] This section sets out ElectraNet's consideration of the materiality of market benefits.

5.1. Change in fuel consumption is the only material category of market benefit

ElectraNet considers that the only material category of market benefit for the options considered in this RIT-T is changes in fuel consumption arising through different patterns of generation dispatch where there are non-network options. In particular, the operation of a new BESS in the NEM (as the result of adopting a non-network option) has the potential to impact the pattern of generator dispatch.

The estimation of potential fuel cost benefits has informed the assessment of Option 4. ElectraNet has applied a proportionate approach to estimating the potential quantum of this benefit (described in section 6 and in Appendix B).

Changes in fuel consumption as a market benefit category is not relevant for network options (i.e., Option 1 and Option 2), as they do not impact the pattern of generator dispatch.

Other market benefit categories linked to changes in wholesale market outcomes are not considered material for this RIT-T. The credible network options assessed in the NPV analysis do not address network constraints between competing generation centres and, as such, are not expected to result in changes in dispatch outcomes or wholesale market prices.

5.2. No other category of market benefit is considered material

ElectraNet considers that there are no other categories of market benefit that are material in the RIT-T assessment. Specifically in relation to:

- **changes in voluntary and involuntary load curtailment:** additional reactive power capability will mitigate against the need to de-energise lines but, due to the meshed nature of the network, the impact on load shedding is not considered material. ElectraNet has not estimated the expected change in unserved energy under the option cases, as it is expected to be the same for both credible options assessed (and so will not be material to the RIT-T outcome);
- **changes in costs for parties, other than the RIT-T proponent:** installing reactive power capability on the network does not affect the timing of new plant, capital costs or operational and maintenance costs for other parties.;
- **differences in the timing of unrelated network expenditure:** each option is designed to achieve a similar operational outcome and address a potential breach of ElectraNet's regulatory obligations and, as such, it is unlikely any potential transmission investment at a future date will be materially impacted differently between the options;[17]

[16] AER, *Regulatory investment test for transmission,* Application guidelines, August 2020, p 29.

[17] The PSCR considered that distribution investment by SA Power network may potentially be affected. However, ElectraNet has concluded that it is unlikely that any potential distribution investment will be materially impacted differently between the options.

- **changes in ancillary service costs:** the credible options considered are equivalent in terms of the voltage control service they provide and, as such, none are expected to have a relative impact on ancillary service costs;
- **competition benefits:** due to the localised nature of the voltage issues, ElectraNet does not consider that any of the credible options will materially affect competition between generators;
- **option value:** option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change and the credible options considered by the TNSP are sufficiently flexible to respond to that change. None of these conditions apply to this RIT-T; and
- **changes in network losses:** the credible options will be installed at or near the areas where the services will be utilised, and the effectiveness of the solution is dependent on these locations. There are not expected to be any material differences in network losses between options.

ElectraNet notes the recent introduction of an emissions reduction objective into the national energy objectives, and that the NER are currently being updated to add a new category of market benefit to the RIT-T reflecting changes in Australia’s greenhouse gas emissions. While we acknowledge this important change to the RIT-T, we note that there is not expected to be a material difference in greenhouse gas emission levels between the two network options assessed in this PADR, as neither option affects generation dispatch. This benefit category is not therefore expected to be material to the outcome of this RIT-T.

6. Assessing Option 4 (hybrid option)

In assessing a potential hybrid option, ElectraNet had regard to the AER's guidance regarding what constitutes an economically feasible option.

According to the AER's guidance, economic feasibility depends on the circumstances of the RIT-T assessment but, as a general guide, an option is likely to be economically feasible where either:

- its estimated costs are comparable to other credible options that meet the identified need[18]
- the option has higher expected costs but is expected to deliver higher market benefits.[19]

In other words, economic feasibility turns on the balance of the costs and benefits of an option.

ElectraNet has applied a two-stage process to assessing the economic feasibility of adding non-network components into a hybrid option, i.e.:

1. first, assessing whether the incremental benefits of the non-network option outweigh its incremental costs; and
2. second, if this is the case, assessing whether the option represents the least cost option for consumers by reference to the cost per effective MVAr provided.

6.1. Assessing the economic feasibility of a hybrid option

The estimated cost of each BESS was set out in Table 3.1.[20]

Table 3.1 shows that the cost of each NNO is substantially more than the cost of any of the reactors included in Option 1. Further, the contribution to the identified need, in terms of effective MVAr delivered, is typically smaller.

It follows from this that neither BESS A nor BESS E has incremental benefits, in terms of the identified need, that outweigh their incremental costs.

Moving to the second stage of the above process, we consider whether either BESS A or BESS E would provide additional market benefits sufficient to offset their additional cost.

The only material category of market benefit for the BESS solutions is changes in fuel consumption arising through different patterns of generation dispatch, resulting from the operation of a new BESS in the NEM.

ElectraNet does not consider that undertaking wholesale market modelling is proportionate to the scale and impact of the BESS non-network options in the context of this RIT-T.

Instead, ElectraNet has adopted a more proportionate approach that assumes that the non-network options always displace gas generation – this reflects the limited number of conventional generators used in South Australia. This approach will tend to overstate the value of fuel substitution, given that gas it the highest cost conventional fuel on a levelized $ per MWh basis. As such, this assumption favours the non-network options.[21] Appendix C

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[18] AER, *Regulatory investment test for transmission,* Application guidelines, August 2020, p 12.

[19] AER, *Regulatory investment test for transmission,* Application guidelines, August 2020, p 12.

[20] As discussed above, costs were modelled using the information provided by the proponent or, where this information was not provided, relevant data from the Australian Energy Market Operator's (AEMO's) 2023 Inputs, Assumptions and Scenarios Report (IASR). This is detailed in Appendix B.

[21] ElectraNet notes that while the operation of BESSs is likely to affect the wholesale price, changes in price are treated as a transfer under the RIT-T and, as such, do not form part of the assessment of market benefits.

sets out the methodology for quantifying the costs and benefits of the non-network options in greater detail.

Applying the above approach, ElectraNet has compared the annualised costs and benefits of each of the BESS $A_{combined}$ BESS E options. In each case the market benefits are too small to offset their incremental capital and operating costs relative to the reactor they defer. The results of this analysis are set out in Table 6.1

The annualised net benefit of these two BESS options ranges from negative $31 million to negative $88 million, relative to the alternative of deploying the reactor under Option 1. While there is an expenditure reduction benefit for ElectraNet associated with displacing one of the reactors, this is insufficient to balance the costs and benefits of these non-network options, given the relative costs involved.

Table 6.1 - Assessment of economic feasibility of non-network options

<table>
<tr><th>Option</th><th>Location</th><th>Electrical Weight</th><th>Cost
($m)/effective MVAr)</th><th>Incremental economic cost of adopting option ($m)</th></tr>
<tr><td>A_1</td><td>Mobilong 132 kV</td><td>0.094</td><td>9.4</td><td rowspan="2">$88</td></tr>
<tr><td>A_2</td><td>Brinkworth 275 kV</td><td>0.201</td><td>12.1</td></tr>
<tr><td>E</td><td>Tungkillo 275 kV</td><td>0.332</td><td>35.4</td><td>$31</td></tr>
</table>

* The BESSs that comprise non-network option A have the same proponent. Both are required to potentially form part of a credible option. They are therefore presented as a single option.

6.2. Additional analysis – committed or anticipated projects

The appropriate approach to the above analysis differs if the projects are included in the base case.

It is appropriate to include a project in the base case if it is *committed* and potentially if it is *anticipated.* Neither BESS A nor BESS E is committed.

Proponent D reached committed status on 15 December 2023. This project has a small MVAr impact at Para as discussed in section 4.4 and its inclusion in the preferred option or otherwise is not impacted by its updated investment status.

Our view is that neither BESS A nor E is properly described as *anticipated.* However, for the avoidance of doubt, we have repeated the analysis on the assumption that BESS A and E (separately) are anticipated and so should be included in the base case for the analysis.

Including non-network options in the base case means that the first step in ElectraNet's assessment of economic feasibility, i.e., assessing whether incremental benefits outweigh incremental costs – is no longer necessary. Projects that are included in the base case are to be assessed based on their *incremental* rather than *total* costs.

However, the second step in ElectraNet's assessment of economic feasibility – assessing the cost per effective MVAr provided – applies equally to the case in which these two options are included in the base case.

As shown above, the cost per effective MVAr provided by option 1 is materially lower than the corresponding cost of MVAr provided by either BESS A or E.

Therefore, even if they were included in the base case, neither of these BESS would form part of the preferred option because neither is economically feasible.

6.3. Conclusion on assessment of Option 4

The outcome of the analysis set out in this section is that Option 4 (i.e., a hybrid option of BESS and reactors) cannot be the preferred option under the RIT-T.

Given that SVCs are more costly than reactors, it is also not possible for the preferred option to be a hybrid of BESS and SVCs.

For this reason, only Options 1 and 2 are taken through to the NPV analysis below.

7. Overview of the NPV assessment approach

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

7.1. Description of the base case

Section 6 explains that the costs and benefits of credible options under the RIT-T are measured against a base case. The base case in this RIT-T reflects continued voltage control issues on ElectraNet's network with the SVCs continuing to operate outside of their recommended range.

These voltage control issues are not necessarily expected to result in frequent unserved energy. However, they do have the potential to lead to cascading voltages on the network, which could lead to a 'system black'.

ElectraNet does not consider it necessary or proportionate to estimate the unserved energy in the base case for this RIT-T, as we are undertaking the investment to ensure continued compliance with the NER obligations (i.e., this is a reliability corrective action, and so the investment is not required to have a positive net market benefit).

7.2. Assessment period and discount rate

The RIT-T analysis considers a 20-year assessment period from 2023-24 to 2042-43. A 20-year period takes into account the size, complexity and expected lives of the options and provides for 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 as the undepreciated value of capital costs at the end of the analysis period.

A real, pre-tax discount rate of 7.0 per cent has been adopted as the central assumption for the NPV analysis presented in this PADR, consistent with the assumptions adopted in the 2023 IASR and AEMO's Step Change ISP scenario.

The RIT-T also requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. ElectraNet has therefore tested the sensitivity of the results to a lower bound discount rate of 3.21 per cent,[22] and an upper bound discount rate of 10.50 per cent (being the upper bound in the 2023 IASR).

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22 This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM. See AER, *Transgrid 2023-28 – Final Decision – PTRM*, April 2023, 'WACC' tab in the model.

7.3. Approach to estimating costs

ElectraNet has prepared cost estimates reflecting the AACE cost estimate classification system (either AACE class 4 or AACE class 5) for reactor components of the two credible network options in this RIT-T. The class 4 estimates are of an expected accuracy of +50%/-30%,[23] whilst the class 5 estimates are +100%/-50%.

Class 4 estimates have been developed for reactors in locations where they can contribute the most to the MVAr requirement, with class 5 estimates have been used for other locations (due to the costs of developing class 4 estimates for locations likely to be less highly ranked).

A summary of ElectraNet's approach to cost estimating is provided in Appendix C.

The cost estimate for each of the reactors is based on a scope prepared by ElectraNet's asset engineering team through a desktop review. In summary:

- in each case the scope includes installing the following items, with common cost assumptions in each case:
  - one 275kV, 60 MVAr reactor (or 50 MVAr in the case of the proposed South East reactor)
  - footing and bunding for the reactor
  - disconnector
  - current transformer
  - circuit breaker
  - surge arresters
  - busbar support with post insulators
  - connection of the reactor to the substation oil containment system
  - oil/water separator installed in the reactor bund
  - protection, control, SCADA and if available for the site the connection to the existing voltage control scheme
- the cost variation between estimates reflects local conditions, in particular:
  - whether civil works are required to extend the substation yard, and the extent of those works
  - fire walls –as required
  - whether additional switchgear is required in the yard
  - extension of the existing substation busbars, lighting, lightning, cable conduits and trenching
  - the suitability of the existing oil containment system
- the estimates were prepared according to ElectraNet's standard estimating procedure using historical and current cost data.

No explicit contingency allowance has been added to the estimates, though we note that the estimates are accurately interpreted as ranges rather than the point estimates used in the analysis presented in this PADR. We have accordingly undertaken sensitivity analysis on the impact of any changes in capital costs on the identification of the preferred option.

23 i.e., the high end range for the costs may be 50% above the point estimate used in this RIT-T assessment, with a low end range of 30% below the point estimate.

The resulting reactor cost estimates are presented in Table 4.1.

The cost estimate for the four 275kV connected SVC (with 60 MVAr reactive absorb range each) included as part of Option 2 has been estimated based on budget supply cost estimates for a single SVC and installation at a Munno Para and escalated to an equivalent size as the reactor solutions.

In addition, both Option 1 and Option 2 include implementing automatic control schemes for transmission-connected reactive plant and automation of on-load tap changers at over 40 sites across the state. The cost of these activities has been estimated at $16.7m, based on the identified number of sites and generic cost per site.

The proposed BESS are not ElectraNet's projects. For this reason, ElectraNet is not able to confirm the methodology used to develop the estimated project costs provided by proponents. As noted in chapter 6 , ElectraNet relied on assumptions from AEMO's 2023 IASR for the analysis presented in this PADR.

7.4. A single scenario has been modelled

The RIT-T must include any of the ISP scenarios from the most recent IASR that are relevant unless:[24]

- 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 application guidelines clarify 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.[25]

For the purposes of this RIT-T, ElectraNet has only modelled outcomes under the Step Change ISP scenario. This scenario was selected because it is identified as the most likely scenario under AEMO's latest Integrated System Plan (ISP). The key assumption adopted from the Step Change scenario is the discount rate used for the analysis.

Other ISP scenarios differ across a range of parameters, including forecast demand and the approach to decarbonisation. However, these differences principally affect the estimation of wholesale market benefits. Since no categories of wholesale market benefit are material to the NPV assessment of the two credible network options included in this PADR, adopting a single scenario approach is appropriate.

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24 AER, *Regulatory investment test for transmission,* August 2020, para 20(b).

25 AER, *Regulatory investment test for transmission,* Application guidelines, August 2020, p 41.

8. Net present value results

This section outlines the results of the assessment ElectraNet has undertaken of the credible options for this RIT-T.

8.1. Estimated gross benefits

Chapter 5 explains that no categories of wholesale market benefit are considered material in relation to the two credible network options assessed in the NPV analysis under this RIT-T.[26] Accordingly, ElectraNet has not quantified any market benefits in the NPV assessment for this RIT-T.[27]

8.2. Estimated costs and net market benefits

The table below summarises the present value of capital and operating & maintenance costs for each credible option relative to the base case. Since no benefits have been quantified it also represents the net economic benefits for each credible option.

The results show that Option 1 has the greatest net market benefits out of the two credible options considered. Since no benefits have been quantified (and would be equal across the credible options in any case, as it they would relate to avoided unserved energy) the key factor driving this result is that Option 1 can be delivered at a lower estimated cost than Option 2 (in NPV terms). While net market benefits are negative, this is permitted under the RIT-T because the identified need is reliability corrective action.

Table 8 - Net benefits relative to the base case, (PV $m 2023-24)

Option/scenario	Step change	Ranking
Option 1	-74.3	1
Option 2	-157.5	2
Option 3	Not credible	n/a
Option 4	Not computed – but would have a higher net cost	3

8.3. Sensitivity testing

ElectraNet has undertaken sensitivity testing to examine how the net market benefit of the credible options change with respect to changes in key modelling assumptions. The factors tested as part of the sensitivity analysis in this PADR are:

- higher or lower capital costs of the credible options; and
- alternate commercial discount rate assumptions.

The sensitivity testing was undertaken against the Step Change scenario. Specifically, ElectraNet individually varied each of the two factors identified above and estimated the net market benefit relative to the base case, while holding all other assumptions constant. The following sections set out the results of this sensitivity analysis.

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26 Potential wholesale market benefits were considered in evaluating whether the proposed non-network options could form part of a credible option.

27 Market benefits have been considered in assessing NNO as part of Option 4.

8.3.1. 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 capital costs that are:

- 50 per cent higher than those in the Step Change scenario – the 'high capex' sensitivity; and
- 30 per cent lower than those in the Step Change scenario – the 'low capex' sensitivity.

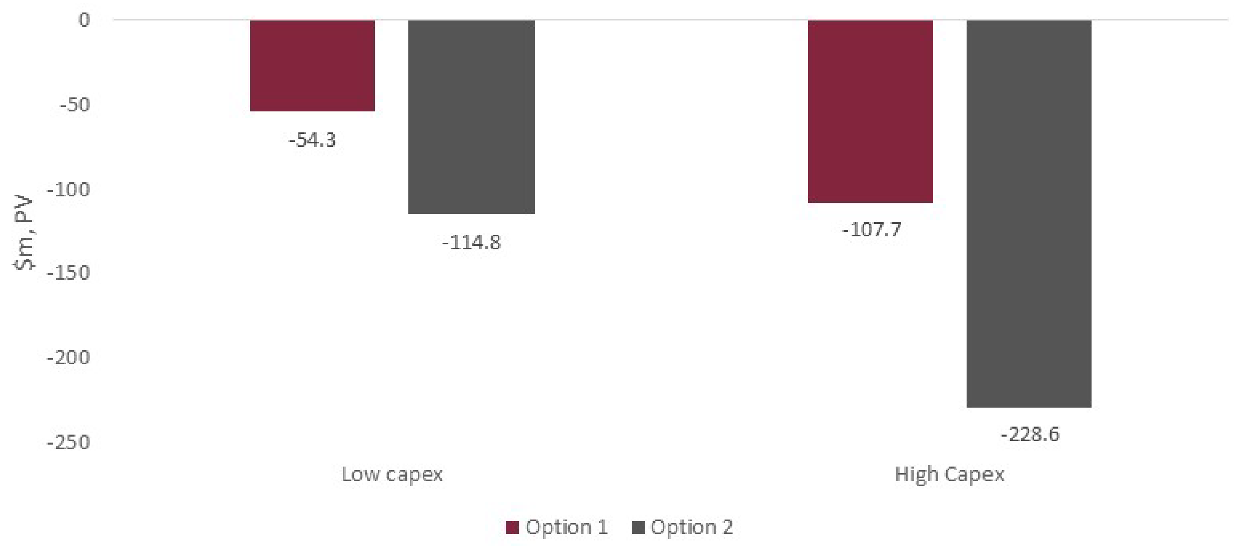
This sensitivity test is consistent with the expected accuracy of the capital cost estimates at this stage of the RIT-T (i.e., they are AACE class 4 estimates).

The option ranking for each sensitivity does not change to the main results presented above, i.e., Option 1 remains the preferred option.

Table 8.1 - Net benefits relative to the base case – low and high capex sensitivities, (PV $m 2023-24)

Option/sensitivity	Low capex	High capex	Ranking
Sensitivity	Step Change estimate - 30%	Step Change Estimate +50%	
Option 1	-54.3	-107.7	1
Option 2	-114.8	-228.6	2

Figure 8.1 - Net benefits relative to the base case – low and high capex sensitivities, (PV $m 2023-24)



ElectraNet has also undertaken a threshold analysis to identify whether a change in capital cost estimates would change the outcome of the RIT-T. Specifically, ElectraNet considered whether an increase or decrease in the capital costs of one option – holding the capital cost of the other option constant – would change RIT-T outcome.

This analysis shows that Option 1's capex would need to increase by more than 125 per cent of its current baseline capex estimate for the outcome of the RIT-T to change, i.e., for Option 2 to be preferred. Similarly, ElectraNet found that Option 2's capex would need to decrease by more than 58 per cent to change the RIT-T outcome.

We consider the change in capital costs of these magnitudes, relative to each other are highly unlikely, and therefore consider the outcome of Option 1 being the first ranked option is robust to changes in capital costs.

8.3.2. Sensitivity analysis on the discount rate

The table and figure below set out the net market benefits for each credible option relative to the base case if alternative discount rates are adopted. Specifically, ElectraNet considered:

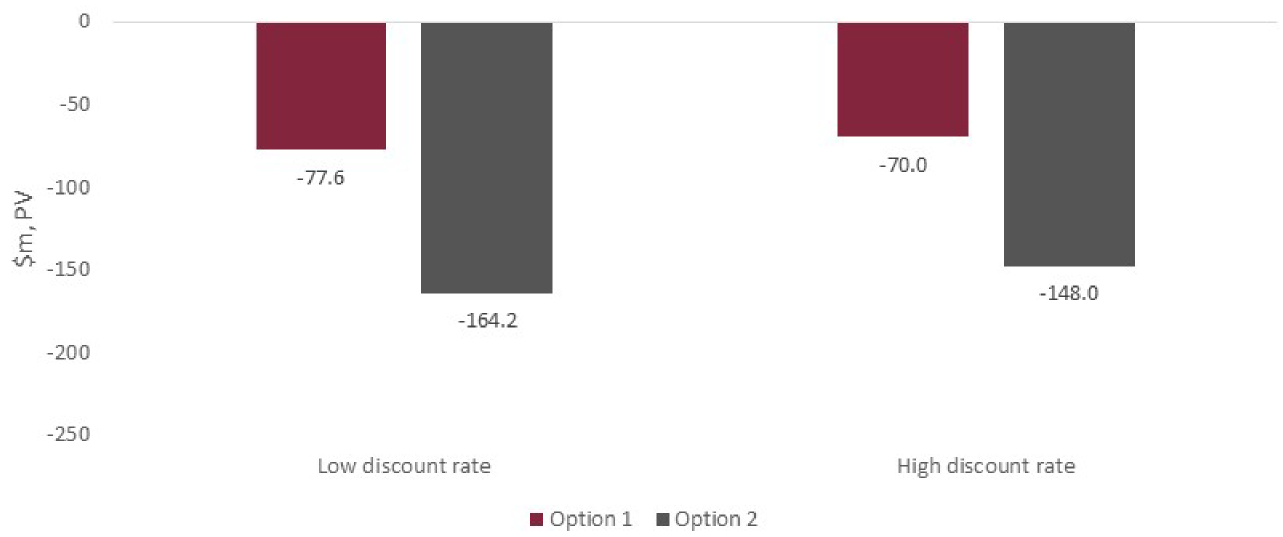
- a low discount rate of 3.21 per cent, which is consistent with the AER's latest determination for a TNSP – the low discount rate sensitivity; and
- a high discount rate of 10.50 per cent, which aligns with the discount rate scenario in the 2021 IASR – the high discount rate sensitivity.

The option ranking for each sensitivity does not change to the main results presented above, i.e., Option 1 remains the preferred option.

Table 8.2 - Net benefits relative to the base case – low and high discount rates, (PV $m 2023-24)

Option/sensitivity	Low discount rate	High discount rate	Ranking
Sensitivity	3.21%	10.50%	
Option 1	-77.6	-70.0	1
Option 2	-164.2	-148.0	2

Figure 8.2 - Net benefits relative to the base case – low and high discount rates, (PV $m 2023-24)



ElectraNet has also undertaken a threshold analysis to identify whether a change in discount rate would change the outcome of the RIT-T. We find that there is no reasonable discount rate[28] that would cause Option 2 would be preferred over Option 1.

[28] The discount rate would need to be over 2 trillion per cent for Option 1 and Option 2 to be equal.

9. Draft conclusion

Option 1 is the preferred option at this draft stage of the RIT-T and involves the installation of six switchable 275kV reactors in the Adelaide and South East regions. Specifically, it comprises installing:

- five 60 MVAr switched 275kV reactors in the Adelaide metropolitan region (at Cherry Gardens, Para, Parafield Gardens West, Torrens Island and Magill); and
- one 50 MVAr 275kV reactor on the transfer corridor between South East and Adelaide (at South East substation).

Option 1 also includes implementing automatic control schemes for transmission-connected reactive plant and automation of on-load tap changers at 32 connection points.

The estimated capital cost of this option is $85.7 million, with operating costs assumed to be one per cent of capital costs. The option is expected to take one-to-two years to design and construct, with commissioning taking place progressively through financial year 2026.

Appendices

Appendix A Compliance checklist

This appendix sets out a compliance checklist that demonstrates the compliance of this PADR with the requirements of clause 5.16.4 of the NER version 203.

Table A. 1 - compliance checklist

Rules clause	Summary of requirements	Relevant section(s) in PADR
5.16.4(k)	A RIT-T proponent must prepare a report (the assessment draft report), which must include:	-
	(1) a description of each credible option assessed	4 and 5
	(2) a summary of, and commentary on, the submissions to the project specification consultation report	3
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option	4, 5 and 6.3
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost	5 and 6
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material	5
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions)	N/A
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results	8
	(8) the identification of the proposed preferred option	9
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the regulatory investment test for transmission	4 and 9

Appendix B Adelaide Metropolitan Region Voltage Control

B.1. Background

The *Transmission Network Voltage Control*, RIT-T Project Specification Consultation Report (RIT-T PSCR) published in December 2022 identified the need to manage high transmission network voltages attributed to transmission line charging during periods of low or zero system operational demand conditions. The voltage control shortfalls were noted in the RIT-T PSCR as 200 – 400 MVAr in the Adelaide Metropolitan Region and 50 - 100 MVAr in the South East Region.

Several submissions were received in response to the RIT-T PSCR offering proposed solutions to address the identified need broadly including the provision of a defined level of reactive support as part of a generating system.

B.2. Reactive Support Effectiveness

To investigate the effectiveness of the location of reactive support on the transmission network, the following high-level load flow assessment was undertaken:

1. For simplicity, the reactive support was represented as a static switchable reactor;
2. A defined amount of reactive support was connected to a network location;
3. The change to the reactive range availability on the Para SVCs and TIPS BESS attributed to the addition of this reactive support was determined;
4. A reactive support effectiveness factor (%) was calculated based on the ratio of range reduction to the additional reactive support:

$$Reactive\ Support\ Effectiveness\ Factor = \frac{PARA\ SVC\ or\ TIPS\ BESS\ (Reactive\ Output_{Pre} -\ Reactive\ Output_{Post})}{Additional\ Reactive\ Support}$$

5. Importantly, the network locations assessed included key network nodes and the locations identified in the received submissions;
6. This assessment considered system normal and single network element outage conditions and changes in system operational demand; and
7. The locations were then ranked.

Table B.2 and Table B.3 below summarise the results of the reactive support investigation for system normal and single network outage conditions.

The effectiveness factor at a number of locations is impacted significantly by single network outage conditions and therefore it is recommended that these locations be avoided.

Locating a reactor on either end of the Magill – East Terrace 275 kV cable would act to reduce cable charging into the transmission network at the “source”.

Table B.2 - System Normal Reactive Support Effectiveness Factor

Location	Reactor Size Assessed (MVAr)	Range Reduction (MVAr)			Reactive Support Effectiveness Factor			System Normal Ranking (PARA)
		Each PARA SVC	Both PARA SVCs	TIPS BESS	Each PARA SVC	Both PARA SVCs	TIPS BESS	
Para 275 kV	60	-14.073	-28.146	-7.049	-0.235	-0.469	-0.117	1
Para 132 kV	40	-9.353	-18.706	-4.932	-0.234	-0.468	-0.123	2
Parafield Gardens West 275 kV	60	-13.258	-26.517	-8.410	-0.221	-0.442	-0.140	3
Munno Para 275 kV	60	-12.984	-25.968	-6.541	-0.216	-0.433	-0.109	4
East Terrace 275 kV	60	-12.595	-25.191	-8.324	-0.210	-0.420	-0.139	5
Magill 275 kV	60	-12.591	-25.182	-8.338	-0.210	-0.420	-0.139	6
Torrens Island 275 kV	60	-11.889	-23.778	-10.509	-0.198	-0.396	-0.175	7
Northfield 275 kV	60	-11.871	-23.742	-10.470	-0.198	-0.396	-0.174	8
Happy Valley 275 kV	60	-11.279	-22.558	-7.882	-0.188	-0.376	-0.131	9
Morphett Vale East 275 kV	60	-11.088	-22.175	-7.800	-0.185	-0.370	-0.130	10
Cherry Gardens 275 kV	60	-10.892	-21.784	-7.696	-0.182	-0.363	-0.128	11
Tungkillo 275 kV	60	-9.967	-19.934	-5.950	-0.166	-0.332	-0.099	12

Location	Reactor Size Assessed (MVAr)	Range Reduction (MVAr)			Reactive Support Effectiveness Factor			System Normal Ranking (PARA)
		Each PARA SVC	Both PARA SVCs	TIPS BESS	Each PARA SVC	Both PARA SVCs	TIPS BESS	
Brinkworth 275 kV	60	-6.028	-12.057	-3.466	-0.100	-0.201	-0.058	13
Mannum 132 kV	30	-1.763	-3.526	-1.523	-0.059	-0.118	-0.051	14
Blyth West 275 kV	60	-3.151	-6.301	-2.212	-0.053	-0.105	-0.037	15
Mobilong 132 kV	30	-1.415	-2.830	-1.343	-0.047	-0.094	-0.045	16
Bungama 275 kV	60	-1.470	-2.940	-1.224	-0.024	-0.049	-0.020	17

Table B.3 - Single Network Outage Reactive Support Effectiveness Factor

Location	Reactor Size Assessed (MVAr)	Single Network Outage	Reactive Support Effectiveness Factor		Single Network Outage Ranking (PARA)
			PARA SVCs	TIPS BESS	
Para 275 kV	60	Any of the exits	Same as system normal		1
Para 132 kV	40	Para 275/132 kV transformer	0	0	
Parafield Gardens West 275 kV	60	Any of the exits	Same as system normal		2
Munno Para 275 kV	60	Munno Para – Para 275 kV line	0	0	
East Terrace 275 kV	60	Any of the exits	Same as system normal		3
Magill 275 kV	60	Any of the exits	Same as system normal		4
Torrens Island 275 kV	60	Any of the exits	Same as system normal		5
Northfield 275 kV	60	Any of the exits	Same as system normal		6
Happy Valley 275 kV	60	Any of the exits	Same as system normal		7
Morphett Vale East 275 kV	60	Any of the exits	Same as system normal		8
Cherry Gardens 275 kV	60	Any of the exits	Same as system normal		9
Tungkillo 275 kV	60	Any of the exits	Same as system normal		10
Brinkworth 275 kV	60	Brinkworth – Templers West 275 kV line	0	0	
Blyth West 275 kV	60	Blyth West – Munno Para 275 kV line	0	0	
Bungama 275 kV	60	Bungama – Blyth West 275 kV line	0	0	

B.3. Para SVC Dynamic Range

The ElectraNet planning criteria has a requirement to maintain dynamic range on SVCs and sync cons under system normal conditions to within 0 – 25 MVAr inductive only. Table 3 summarises results of application of this requirement and the broader ElectraNet planning criteria in the Adelaide Metropolitan Region in the scenario where system demand is 0 MW, and no synchronous generation is in-service.

Table B.4 - Maintaining Para SVC range

0 MW demand Condition System Normal, 50 MVAr Cherry Gardens reactor	Para SVC Output (MVAr on each unit)	Complies with planning criteria"
Additional 3 x 60 MVAr metro reactors	-44.3	X
Additional 4 x 60 MVAr metro reactors	-24.9	√
Additional 3 x 60 MVAr reactors and Blyth West BESS	-39.1	X
Additional 3 x 60 MVAr reactors, Blyth West BESS and Templers BESS	-38.4	X

Table B.4 indicates that four 60 MVAr reactors connected to the Adelaide Metropolitan 275 kV are required in addition to the Cherry Gardens 275 kV reactor that was energised in Q3 2023 to ensure compliance with the ElectraNet planning criteria. The results in Table 3 are based on four reactors in the metropolitan region.

The effectiveness factors and rankings from Table 2 are recommended to be used to inform the optimal location for the four required reactors in addition to feasibility of connection and capital cost at each substation location.

Appendix C Assessing economic feasibility of BESS (as part of option 4)

Chapter 6 explains that ElectraNet assessed the economic feasibility of non-network options by comparing the balance of the project's costs and market benefits. This appendix sets out ElectraNet's approach and the assumptions used in quantifying these costs and benefits.

C.1. Assumptions underpinning the modelling approach

The table below summarises the key assumptions underpinning ElectraNet's simplified modelling approach to estimating the costs and benefits of the non-network options proposed in response to the PSCR. The subsequent sections expand on these assumptions.

Table C.5 - Key assumptions underpinning modelling of NNO costs and benefits

Assumption	Value	Units
IASR BESS Capex (2 hrs storage)	$1.45	$m/MW capacity
IASR BESS Capex (4 hrs storage)	$2.35	$m/MW capacity
IASR BESS Capex (8 hrs storage)	$4.17	$m/MW capacity
BESS Round trip efficiency	85.60%	
Charging cost	50	$/MWh
Assumed cycles per annum	365	cycles
Avoided gas generator - heat rate	8.8	GL / MW
Avoided gas generator - gas price	10.96	$/GJ
Rate of return	7.00%	% p.a.

C.2. Capital and operating costs of NNOs

Under the RIT-T framework, the full resource cost of a non-network option is required to be assessed where the project is not committed or anticipated (and is therefore not included in the base case). Accordingly, ElectraNet used the EOI process following the PSCR to request information from proponents regarding the expected capital and operating costs of their projects.

However, to ensure consistent treatment of the various NNOs that were proposed, we adopted the relevant BESS assumptions from the 2023 IASR as shown in Table C.5 above.

C.3. BESS cycle rate

Assessing the economic feasibility of a BESS requires an assumption regarding how the BESS will operate, because the operating profile of a BESS will shape how it affects any change in fuel cost arising from different dispatch patterns. This also turns on how much energy the BESS charges and discharges, as well as the generator or type of generator that is being displaced.

ElectraNet acknowledges that BESS operating models are complex, and it is reasonable to expect that each BESS operator would apply its own detailed approach. However, a reasonable operating principle is that a BESS will charge when electricity is cheap and discharge when electricity is expensive. In the South Australian context, this can be approximated by the assumption that a BESS will charge during daylight hours when solar generation is in abundance and discharge in the evenings and early mornings when prices are typically higher.

ElectraNet has therefore assumed that, on average over the course of a year, each BESS will cycle 365 times. This is equivalent to the BESS cycling once each day – charging during daylight hours and discharging for the evening peak.

C.4. Valuing changes in fuel consumption arising through different patterns of generation dispatch

Estimating changes in fuel consumption arising through different patterns of generation dispatch typically requires wholesale market modelling. However, as explained in section6, ElectraNet does not consider that this is a proportionate approach in the context of this RIT-T. ElectraNet has instead adopted a simplified approach.

This simplified approach draws on the characteristics of the South Australian generation mix. South Australia's generation mix is substantially renewable. There is no coal generation and the available gas generation that might have daily operation into the future comprises:

- Barker Inlet Power Station (heat rate 7.89);
- Pelican Point Power Station (heat rate 7.35)
- Ladbroke Grove Power station (heat rate 11.88);
- Quarantine Power Station (heat rate 10.71) and
- Bolivar Power Station (heat rate 10.19).

In practice, the generator whose output is displaced by a given BESS will vary frequently and depend on market conditions. The displaced generator may vary between thermal and renewable generators. Rather than model these dynamics, ElectraNet has assumed that the non-network options considered as part of this PADR would always displace gas generation (in each of the cycles described above). This is a favourable assumption to non-network proponents because it means that the BESSs would always be displacing a more expensive fuel, i.e., the assumption means that there is always a reduction in fuel costs when the BESS operates (when this need not be the case).

Where the analysis indicates that the non-network option would not be economic even based on this assumption, it also follows that it would not be economic based on less favourable (but more realistic) assumptions.

ElectraNet has quantified the fuel displaced by assuming, based on the 2023 IASR, that the displaced generator is an average of the fleet with a heat rate of 8.8 gigajoules of gas per megawatt hour of electricity generated. ElectraNet has assumed the cost of gas displaced is $10.96 per gigajoule, also based on the 2023 IASR.

Appendix D Approach to cost estimation for different AACE classes

The table below provides additional detail on ElectraNet's cost estimation approach.

Table D.6 - Summary of cost estimation classes

Estimate Class	Level of Project Definition	Low expected	High expected	Scope Requirements
Class 5	0-2%	-50% %	+100%	Single Line Diagram, length and voltage of Transmission Line, Transformer rating, Bench size of Substation (number of diameter), reference benchmark of recent similar project.
Class 4	1-15%	-30%	+50%	Scope document that includes single line diagram sketches and defined scope for Infrastructure, Primary plant, Secondary systems, Line, Telecommunications.
Class 3	10-40%	-20%	+30%	Full set of Contract drawings and ECS's (as sent to our Contractors for pricing)
Class 2	30-75%	-15%	+20%	Copy of the preferred Contractors construction or supply bids. Copy of free issue ordered or to be ordered. ElectraNet Actuals to date. Forecast of internal cost and support until project completion. Project Contingency.
Class 1	65-100%	-10%	+15%	All information required for Capitalisation of Project Assets.