electranet

Northern Transmission Project (NTx)

Project Assessment Draft Report

April 2026

Copyright and Disclaimer

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

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

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

- Independently verify and check the currency, accuracy, completeness, reliability and suitability of that information
- Independently verify and check the currency, accuracy, completeness, reliability and suitability of reports relied on by ElectraNet in preparing these documents

Obtain independent and specific advice from appropriate experts or other sources.

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

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

Privacy notice

ElectraNet is bound by the Privacy Act 1988 (Cth). In making submissions in response to this consultation process, ElectraNet will collect and hold your personal information such as your name, email address, employer and phone number for the purpose of receiving and following up on your submissions.

Under the National Electricity Law, there are circumstances where ElectraNet may be compelled to provide information to the Australian Energy Regulator (AER).

ElectraNet's Privacy Policy sets out the approach to managing your personal information. It explains how you may seek to access or correct the personal information held about you, how to make a complaint about a breach of our obligations under the Privacy Act, and how ElectraNet will deal with complaints. You can access the Privacy Policy here.

Executive Summary

ElectraNet is exploring options for increasing the power system capability of the Mid North region of the South Australian transmission network, in accordance with the actionable ISP framework.

This project is referred to as the Northern Transmission Project ('NTx') and is required to supply growing demand in South Australia. NTx will alleviate congestion between the Mid North region and Adelaide, boosting access to renewable resources in the Upper Spencer Gulf and supporting renewable integration thereby meeting AEMO's identified need.

This Project Assessment Draft Report (PADR) is the next step in the Regulatory Investment Test for Transmission (RIT-T) process for NTx.

Overview

The assessment in this PADR finds that a new high capacity 275 kV transmission line between Bundey in the Mid North and a new site (around Bolivar/Dry Creek) is the preferred option and has the greatest expected net market benefits of the credible options assessed.

This is referred to as 'Option S2' and is expected to deliver approximately $356 million of net market benefits over the assessment period (weighted across all the 2026 ISP scenarios) in present value terms. Option S2 also delivers positive net market benefits in each of the three 2026 ISP scenarios.

Augmenting this part of South Australia's transmission network:

- supports growing demand in Adelaide to be supplied by expected increase in renewable generation north of Adelaide;
- provides additional network capacity to supply new large industrial loads, recognising the high level of interest from those loads to connecting to our network; and
- alleviates congestion on renewables from the Mid North region to the rest of the National Electricity Market.

The assessment in this PADR finds that Option S2 has greater net market benefits. In addition, we no longer consider 'Option S1', the ISP candidate option going to Para instead of Bolivar/Dry Creek, to be a likely option given the bushfire risk that comes with connecting new lines at that location (compared to a new site around Bolivar/Dry Creek), and a need to quarantine the existing spare bays at Para for future expansion.

While the core PADR assessment finds that it is not net beneficial to expand the transmission network north of Bundey at this stage, this is expected to change if sufficient additional large industrial load locates in northern South Australia, and the cost of developing additional renewable energy resources in northern South Australia is higher than currently assumed by AEMO. We intend to discuss these assumptions further with AEMO and have included a proposed re-opening trigger in this PADR catering for these circumstances.

The sensitivity testing in this PADR finds the amount/location of new large industrial load matters for the southern options, and may justify a higher-capacity upgrade.

At this stage, we do not consider that any of the non-network submissions constitute a credible non-network solution (either in isolation, or in combination with a network option).

The South Australian energy sector is in the middle of a key transition

South Australia's energy sector, including the electricity network, is evolving to meet the growing demand for reliable energy and support the State's transition to a low-emission energy future.

South Australian economic growth is expected to be driven by investment in critical minerals, water desalination, green metals, data centres, and defence. The government is also aiming for net zero emissions leveraging the state's high quality renewable energy and mineral resources, as seen through Whyalla's Green Steel Transition and the Northern Water plant.

These developments increase electricity demand, requiring upgraded transmission infrastructure to ensure reliable supply. Without action, ElectraNet forecasts increasing congestion on our transmission network and increasing electricity prices. This highlights the need for proactive planning as industrial loads increase. Timely and efficient transmission development delivers lower electricity prices than would otherwise be the case, for all customers.[1]

Wind power now also generates nearly half of South Australia's electricity and is supported by a growing fleet of Battery Energy Storage Systems (BESS) north of Adelaide, with new capacity replacing outgoing gas assets. The Mid North corridor transmits electricity from around 2,200 MW of installed wind generation capacity, with an additional 850 MW anticipated. This is supplemented by more than 650 MW of installed BESS capacity, with 1,650 MW of anticipated BESS. These capacities well exceed the 780 MW of former coal generation that had to be transferred across the Mid North to supply the metropolitan Adelaide.

The Northern Transmission Project (NTx) will meet the 'identified need' by alleviating the congestion between the Mid North and Adelaide, boosting access to the Upper Spencer Gulf, supporting renewable integration and enabling efficient electricity prices. It will further increase access to wind generation outside of high value agricultural lands. This extension to the backbone will increase the transfer capacity and support both higher electricity demand, increase renewables and BESS access and assist with the already announced retirement of gas generation assets going forward.

The ISP framework is a highly constrained modelling exercise that requires ElectraNet to align with all inputs from AEMO. Under this framework, investment in the southern section of NTx delivers a positive net market benefit. However, some ISP scenarios – especially *Slower Growth* - and inputs such as the location and scale of demand across both *Step Change* and *Accelerated Transition* underestimate the value of this project. This PADR presents the analysis as required under the ISP framework, and also highlights some of the critical differences that impact the analysis and underestimate the potential benefits delivered by both the southern and northern sections of NTx.

[1] Endgame Analytics, *Impact of NTx on consumer bills*, 2026.

The Mid North transmission network needs augmentation to support the State's generational economic growth opportunity

The focus of the options considered in this report is to increase the power system capability of the Mid North region of the South Australian transmission network. Specifically, each option has been designed to:

- Support growing demand in Adelaide to be supplied by expected increase in renewable generation north of Adelaide;
- Provide additional network capacity to supply new large industrial loads (LILs);
- Alleviate congestion on renewables from the Mid North to the rest of the National Electricity Market (NEM).

These three drivers form the 'identified need' in the draft 2026 Integrated System Plan (ISP) (and the earlier 2024 ISP) for the project.[2]

This RIT-T is one of many activities undertaken since the project became actionable

This Project Assessment Draft Report (PADR) is the next step in the Regulatory Investment Test for Transmission (RIT-T) process for NTx.

ElectraNet has been actively engaging with affected communities and other stakeholders in relation to NTx, including on corridor selection. The project was included in our latest Transmission Annual Planning Report (TAPR), released in March 2026, and we have been undertaking extensive stakeholder engagement following (and preceding) this.

NTx has also been identified as a national energy priority project by the Commonwealth Department of Climate Change, Energy, the Environment and Water,[3] which will provide the project with additional support and coordination through the environmental approval pathways.

While NTx was identified as an 'actionable ISP project' in the 2024 ISP,[4] the draft 2026 ISP states that it is subject to ongoing analysis and stakeholder engagement to confirm its status, due to uncertainty on input assumptions that could impact the benefits.[5]

We consider that the assessment presented in this PADR demonstrates the value that NTx provides and supports it being confirmed as continuing to be an actionable ISP project in the 2026 ISP.

Nine network options have been assessed

There are two distinct transmission paths of interest for the options considered in this PADR, both of which originate from Bundey substation near Robertstown.

---

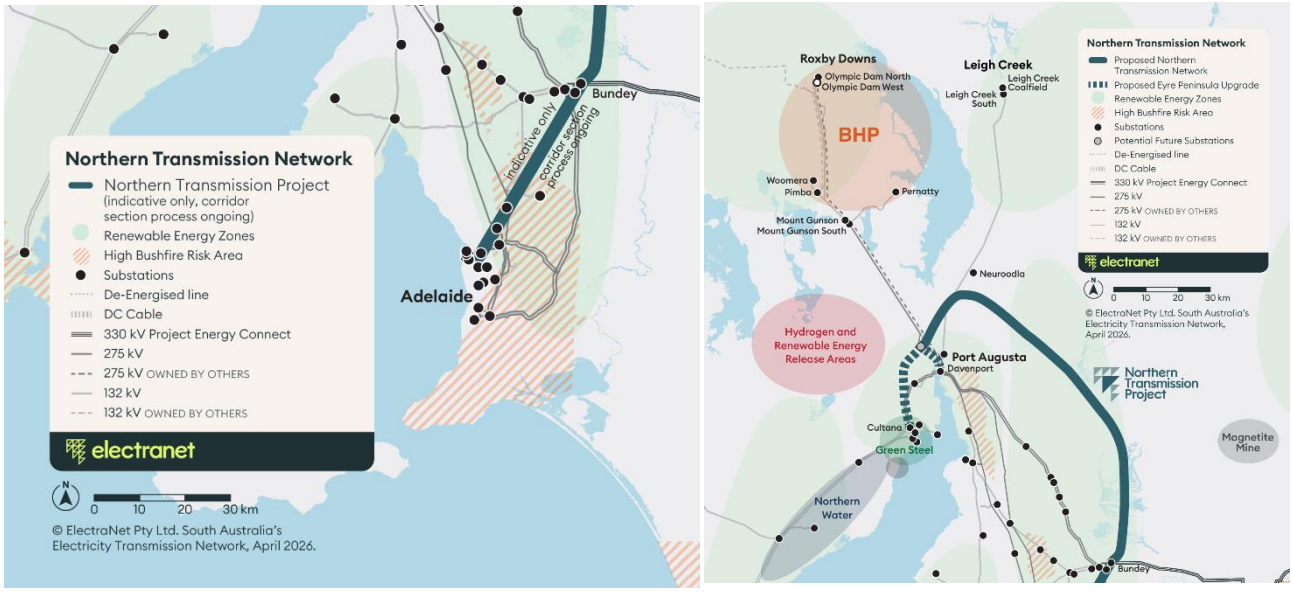
[2] AEMO, *draft 2026 ISP Appendix 5 – Network Investments*, December 2025, p. 54. & AEMO, *2024 ISP Appendix 5 – Network Investments*, June 2024, p 40. The project was referred to as the 'Mid North South Australia REZ Expansion' in the 2024 ISP.
[3] https://www.dcceew.gov.au/energy/renewable/priority-list
[4] The project was referred in the 2024 ISP as the 'Mid North South Australia REZ Expansion' project.
[5] AEMO, *draft 2026 ISP*, December 2025, p. 15.

Specifically, there is the:

- Mid North to Metro Adelaide section (southern section); and
- Mid North to Narcoona[6] section (northern section).

These sections serve complementary purposes in addressing South Australia's electricity network needs and indicative paths are illustrated in the figure below.[7] ElectraNet is working with communities to determine possible routes for the transmission lines.

Figure E.1 – Indicative paths for the southern solutions (LHS) and the northern solutions (RHS)



We have modelled the following **nine options** in this PADR assessment:

- four standalone southern options, consistent with the focus of the draft 2026 ISP candidate option (Options S1-S4);
- four 'end-to-end' options involving the combination of the southern solution that has the highest expected net market benefits and is considered credible (Option S2) with each of the four different northern solutions; and
- the northern solution from the best performing of the 'end-to-end' options as a standalone option (Option N1).

Each of the RIT-T options modelled is summarised in the table below.

[6] This name might change when a more precise location for this site is determined.

[7] The figure shows the relevant part of our network that the solutions would be in. Please note that these figures are indicative and it does not represent a specific route.

Table E.1 – Summary of the options assessed in this PADR[8]

Option	Summary	Additional line capacity	Capital[9] cost(s)
Standalone southern options[10]			
S1	Bundey to Para 275 kV (no longer considered a likely option)	2,000 MW	$902.3m
S2	Bolivar/Dry Creek route 275 kV	2,000 MW	$1,406.4m
S3	Bolivar/Dry Creek 330 kV	2,800 MW	$1,746.3m
S4	Bolivar/Dry Creek 500 kV	7,000 MW	$3,515.8m
'End-to-end' options[11]			
S2 + N1	Highest NPV southern credible option paired with Bundey to Narcoona – 275 kV	2,000 MW (S2) 2,400 MW (N1)	$1,406.4m (S2) $1,726.8m (N1)
S2 + N2	Highest NPV southern credible option paired with Bundey to Narcoona – 330 kV	2,000 MW (S2) 2,800 MW (N2)	$1,406.4m (S2) $2,045.3m (N2)
S2 + N3	Highest NPV southern credible option paired with Bundey to Narcoona – 500 kV	2,000 MW (S2) 7,000 MW (N3)	$1,406.4m (S2) $3,857.7m (N3)
S2 + N4	Highest NPV southern credible option paired with Bundey to Narcoona – staged 500 kV	2,000 MW (S2) 2,200 MW (N4 Stage 1) 7,000 MW (N4 Stage 2)	$1,406.4m (S2) $2,857.6m (N4 Stage 1) $1,436.3m (N4 Stage 2)
Standalone northern option			
N1	Northern component of best performing 'end-to-end' combination	2,400 MW (N1)	$1,726.8m (N1)

[8] All the costs in this table and in the report represent the total costs minus the costs of early works costs that have been incurred and cannot be sold/utilized elsewhere.
[9] These costs are equivalent to 'Class 4' estimates, which represent an expected accuracy of +50%/-30%, with exception of option S4 which corresponds to a 'Class 5' estimate, +100%/-50%.
[10] The final name for the Bolivar/Dry Creek site would be finalized once its final location is determined.
[11] The site name of Narcoona might change when a more precise location for this site is determined

A number of additional network options have been considered over the course of preparing this PADR, and in the earlier 2024 ISP assessment(s). These additional options, and the reasons they have not been progressed, are summarised in the body of this PADR.

We have also assessed two proposed non-network options

In June 2024, AEMO called for non-network options for NTx.[12] Responses were due on 18 September 2024, and AEMO received submissions from the following parties:

- a confidential proponent of a BESS in the Mid North region;
- a confidential proponent proposing to combine a BESS with a solar PV facility in the Mid North region; and
- Lodestone Mines, who are developing a substantial magnetite mining complex in the Olary Flats region (approximately 330 km north-northeast of Adelaide).

ElectraNet has assessed whether each non-network proposal meets or is reasonably likely to meet the identified need. In doing so, we have contacted each proponent to understand their proposals further and we thank each party for their time and efforts to-date.

At this stage, we do not consider that any of the submissions constitute a credible non-network solution (either in isolation, or in combination with a network option).

We understand that the first project above may receive external funding in the coming months that would reduce the effective capital cost of the project in the RIT-T assessment.[13] If this occurs, we will re-examine this proposal to identify whether adding the BESS into the scope of the preferred option is expected to increase the overall net market benefits, prior to the Project Assessment Consultation Report (PACR).

The preferred option is a high capacity 275 kV line between Bundey and a new site around Bolivar or Dry Creek – delivers the greatest net benefits

The PADR assessment finds that a new high capacity 275 kV transmission line between Bundey and a new site (around Bolivar/Dry Creek[14]) – Option S2 – has the greatest expected net market benefits of the credible options.

Option S2 is expected to deliver approximately $356 million of net benefits, in present value terms, over the assessment period when assessed across all ISP scenarios in line with the draft 2026 ISP scenario weightings. Option S2 is found to deliver net benefits of $59 million under the Slower Growth scenario, which increase to $363 million under the Step Change scenario and further to $640 million under the Accelerated Transition scenario.

---

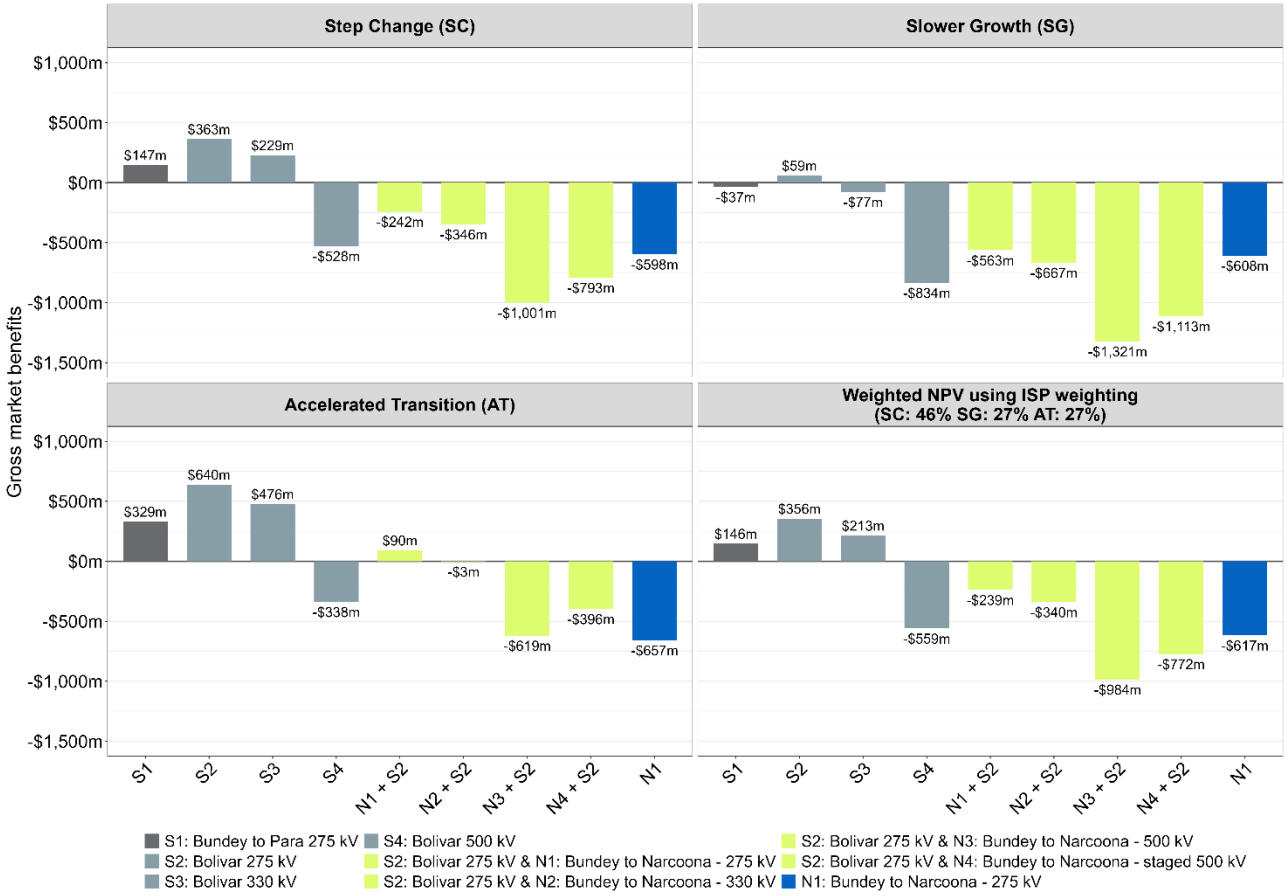
[12] AEMO, 2024 ISP Non network options consultation – Mid North South Australia REZ Expansion, June 2024, available at: https://aemo.com.au/consultations/current-and-closed-consultations/2024-isp-non-network-options-consultation-mid-north-south-australia-rez-expansion, accessed on 16 July 2025.

[13] While this was mentioned in the NTx Progress Report as a reason for the PADR extension, we note that there has been no development on this as at the date of this PADR.

[14] The final name for the site would be finalized once its final location is determined.

While Option S1, the ISP candidate option going to Para instead of Bolivar/Dry Creek, is also found to deliver net benefits on a weighted basis across scenarios, we no longer consider it a likely option given the elevated bushfire risk that comes with connecting new lines at that location (compared to a new site around Bolivar/Dry Creek), and the need to quarantine the existing spare bays at Para for future expansion. While Option S1 has been included in the quantitative assessment in this PADR, as required, we no longer consider this a likely option. We have informed AEMO accordingly.

Figure E.2 – Summary of the estimated net market benefits for each option



While Option S2 is found to deliver only marginally positive net market benefits under the Slower Growth scenario, we consider that this is due to the demand forecasts adopted by AEMO in that scenario not including any LILs. This runs counter to what we are currently seeing from these types of parties wishing to connect to our network.[15]

[15] For example, ElectraNet is currently engaging with 38 individual large industrial customers exploring direct connections to our network, and these customers are planning more than 65 individual projects, with potential interest of more than 2,500 MW of additional load by 2035.

We have therefore investigated a sensitivity that gives the Slower Growth scenario a zero per cent weighting.[16] Under this assumption, the estimated net benefits of Option S2 increase substantially, by 31 per cent (from $356 million to $465 million, in present value terms).

Further, the PADR sensitivity analysis finds, while the preferred option not to be sensitive to the assumed capital costs and commercial discount rate, the amount/location of new LIL demand matters for the southern options, and may justify a higher-capacity upgrade.

ElectraNet notes that the addition of a northern component of NTx is not found to provide additional net benefits at this stage. The exception to this is under the high demand sensitivity for the Accelerated Transition scenario (assuming a constraint on new solar generation). We have therefore included a re-opening trigger to cater for these circumstances.

Further, based on preliminary network modelling, ElectraNet considers that a northern upgrade may allow for additional market benefits from:

- allowing intra-regional transmission investment elsewhere in our network to meet demand from LILs to be avoided; and
- lower connection costs for mines in the Mid North region of South Australia.

Together, these would provide additional benefits for these upgrades. We intend to assess these potential benefits further ahead of the PACR.

Overall, this RIT-T has been drafted in parallel with AEMO's development of the 2026 ISP. The market modelling in this PADR will be updated for the PACR in order to align with the 2026 ISP. ElectraNet notes that this may have an impact on the outcome of the RIT-T assessment.

The current estimated capital cost of Option S2 is $1,406.4 million, and all works are expected to take two years to complete (commencing commissioning by 2029/30).

Supply chain costs

We are monitoring emerging evidence that supply chains are experiencing severe disruption and cost escalation due to the conflict in the middle east.

The escalating costs have not been included in the analysis of this PADR. We will continue to the monitor the evolution of costs related to this project and consider that this may form a demonstratable reason to modify input assumptions for the PACR and ahead of updated IASR inputs.

[16] Our recent submission to the draft 2026 ISP also stated that the Slower Growth scenario should not be a feature in the assessment of the current nor future ISPs given it is too conservative for planning purposes. See: ElectraNet, *Draft 2026 ISP Submission*, 13 February 2026, p.8.

Proposed re-opening triggers

Under the Rules relating to a Material Change in Circumstance (MCC), we are required to set out in the PADR (for consultation and confirmation in the PACR), re-opening triggers for this RIT-T.

Consistent with these requirements and drawing on the results of the sensitivity testing in this PADR, we have considered the impact of changes in key underlying assumptions to identify reopening triggers. Specifically, we consider that the following are expected to form re-opening triggers for this RIT-T:

- real total capital cost increases of more than 77 per cent, which is the amount beyond which the threshold test currently demonstrates that the preferred option will have negative net market benefits; and
- additional new LILs assumed in Northern South Australia, which we currently expect could justify the inclusion of a northern NTx augmentation in addition to a southern one.

To be clear, should either of these events occur, we would update our analysis to identify whether the preferred option in this RIT-T has changed or is no longer expected to provide positive net market benefits, and would propose a course of action to the AER.

We intend to continue to liaise with AEMO on the size and location of LILs in South Australia as part of the 2026 ISP process, as well as around the appropriate costs of renewable energy developments on the Eyre Peninsula and the Upper Spencer Gulf. This may enable the second re-opening trigger above to be further refined in the PACR.

In addition, ElectraNet has assumed that there will be a new substation established close to Davenport and that the existing Davenport to Cultana 275 kV circuits will be duplicated in the base case for this RIT-T assessment (i.e., consistent with the conclusion of the Eyre Peninsula Upgrade RIT-T). If this is not the case, then there will need to be a rescoping of the northern solutions assessed under this RIT-T, and the expected market benefits of all NTx upgrade options (i.e., southern and northern) will need to be reassessed. ElectraNet intends to investigate this further in the PACR and expects that it may form an additional re-opening trigger for this RIT-T.

Submissions and next steps

ElectraNet welcomes written submissions on this PADR. In particular, we would like to hear from proponents of new spot load developments in the Mid North, Eyre Peninsula and Upper North regions of South Australia regarding the status of their proposals given the importance of these developments to the outcome of this RIT-T.

Submissions are due on 11 June 2026.

Submissions should be emailed to our Planning team via consultation@electranet.com.au. In the subject field, please reference 'Northern Transmission Project – PADR feedback'.

The PACR is expected to be published by December 2026. The PACR will take into account any updated analysis contained in AEMO's 2026 ISP, due to be published in June 2026. A Final Investment Decision (FID) is anticipated in June 2028 following the conclusion of the feedback loop process.

If found to deliver net market benefits at the conclusion of this RIT-T, ElectraNet will seek full contingent project funding ('CPA2') in accordance with the process for actionable ISP projects under the National Electricity Rules (NER). In the interim, ElectraNet has received AER approval for

contingent project funding[17] for early works in support of this major project ('CPA1a'),[18] some of which has funded activities (including community engagement) to inform the assessment in this RIT-T.[19]

[17] AER, ElectraNet Mid North South Australia REZ Expansion Stage 1a Early Works Contingent Project Application, Determination, June 2025.

[18] The early works activities include the costs for stakeholder engagement, land use planning and acquisition, project development and procurement activities.

[19] https://www.aer.gov.au/industry/networks/contingent-projects/electranet-northern-transmission-project-stage-1b-early-works-contingent-project

Contents

Appendices

List of Figures

List of Tables

1 Introduction

South Australia's electricity network is evolving to meet the growing demand for reliable energy and support the State's transition to a low-emission energy future.

South Australia is on the cusp of an unprecedented increase in economic activity and development, underpinned by State and Federal government policy aiming to transform both regional and metropolitan areas.

This growth is underpinned by an expansion of major new large industrial loads (LILs). It is imperative that these loads are able to connect to the network efficiently and have access to sufficient electricity to meet their needs. This will ensure that these developments are able to deliver benefits to South Australia, whilst avoiding unnecessary increases in wholesale electricity prices.

This Project Assessment Draft Report (PADR) is the next step in the Regulatory Investment Test for Transmission (RIT-T) process for the Northern Transmission Project (or 'NTx') – a major project supporting both higher electricity demand and the retirement of gas generation assets going forward. While this project was identified as an 'actionable ISP project' in the 2024 Integrated System Plan (ISP),[20] the draft 2026 ISP states that it is subject to ongoing analysis and stakeholder engagement to confirm its status, due to uncertainty on input assumptions that could impact the benefits.[21]

We consider that NTx is vital to relieve network congestion between the Mid North and Adelaide, and reduce electricity prices in South Australia for the South Australian consumer. The assessment presented in this PADR demonstrates the value that NTx provides and supports it continuing to be included as an actionable ISP project in the 2026 ISP.

While the Australian Energy Market Operator (AEMO) required the PADR to be published by 1 December 2025 as part of the 2024 ISP,[22] the Australian Energy Regulator (AER) granted an extension in November 2025 to 3 July 2026.[23] This has enabled ElectraNet to improve the accuracy of key inputs, undertake additional engagement activities and, overall, improve the robustness of the recommendation in this PADR. The size, date and location of proposed future Large Industrial Loads (LILs) continue to be uncertain but given their numbers ElectraNet expects considerable load increases, as detailed in our latest Transmission Annual Planning Report (TAPR), release in March 2026.[24]

In granting the PADR extension, the AER required ElectraNet to publish a progress report against its stakeholder engagement plan for NTx by end of December 2025. This report was published in December 2025 and included an update on our considerations regarding whether the southern

[20] The project was referred in the 2024 ISP as the 'Mid North South Australia REZ Expansion' project.
[21] AEMO, *draft 2026 ISP*, December 2025, p. 15.
[22] AEMO, *2024 ISP*, June 2024, p 62.
[23] https://www.aer.gov.au/news/articles/communications/project-assessment-draft-report-extension-mid-north-south-australia-renewable-energy-zone-expansion-project
[24] ElectraNet, 2026 TAPR, March 2026 available at https://electranet.com.au/wp-content/uploads/2026/03/Electranet-2026-TAPR.pdf

solutions should terminate at the Para substation, as well as the early emerging market benefits for the southern solutions.[25]

ElectraNet has been actively engaging with affected communities and other stakeholders in relation to NTx, including on corridor selection. The project was included in ElectraNet's latest Transmission Annual Planning Report (TAPR), released in March 2026[26]. The NTx project has also been identified as a national energy priority project by the Commonwealth Department of Climate Change, Energy, the Environment and Water,[27] which will provide the project with additional support and coordination through the environmental approval pathways.

If found to deliver net market benefits at the conclusion of this RIT-T, ElectraNet will seek full contingent project funding ('CPA2') in accordance with the process for actionable ISP projects under the National Electricity Rules (NER), around the middle of 2027 including the feedback loop. In the interim, ElectraNet has received AER approval for contingent project funding[28] for early works in support of this major project ('CPA1a'),[29] some of which has funded activities (including community engagement) to inform the assessment in this RIT-T.

1.1 Role of this report

The RIT-T is an economic cost benefit test used to "identify the credible option that maximizes the present value of net economic benefit (the preferred option)"[30]. It assesses and ranks different investment options that address an identified power system need.

This PADR:[31]

- outlines the 'identified need' for the investment, that was identified in the 2024 ISP and recommitted to in the draft 2026 ISP;
- describes the options assessed under this RIT-T, which includes the ISP candidate option;
- discusses the consideration of non-network options, which has been informed by responses to AEMO's separate consultation on potential non-network options as part of the ISP process;
- includes a quantification of the costs of each of the options assessed, based on our most recent estimates, which have been updated from those reflected in the draft 2026 ISP (and have been provided to AEMO for the 2026 ISP);

[25] ElectraNet, *NTx Project Progress Report*, December 2025, available at: https://electranet.com.au/projects/northern-transmission-project-ntx/

[26] The NTx (previously Mid North Expansion) project appeared initially in our Transmission Annual Planning Report Update of May 2023, as a response to potential large industrial loads.

[27] https://www.dcceew.gov.au/energy/renewable/priority-list

[28] AER, ElectraNet Mid North South Australia REZ Expansion Stage 1a Early Works Contingent Project Application, Determination, June 2025.

[29] The early works activities include the costs for stakeholder engagement, land use planning and acquisition, project development and procurement activities.

[30] AER, Regulatory investment test for transmission, Application guidelines. https://www.aer.gov.au/industry/registers/resources/guidelines/regulatory-investment-test-transmission-application-guidelines

[31] Consistent with clauses 5.16A.4(c)–(h) of the NER.

- describes how some of the assumptions in the 2025 IASR and draft 2026 ISP do not reflect the latest information, and why ElectraNet considers there are 'demonstrable reasons' for updating some of the latest ISP parameters (which ElectraNet is engaging with AEMO on as part of the separate ISP process);[32]
- presents the results of the net present value (NPV) analysis for each of the credible options assessed, in each of the ISP scenarios and on a weighted basis;
- describes the key drivers of the NPV results at this stage;
- discusses the sensitivity analysis that has been undertaken to highlight how the outcome of the assessment could change if there is a change in key parameters, including both the scenario weightings and the future demand outlook in South Australia;
- identifies the preferred option at this stage of the RIT-T (that is, the option that is expected to maximise net market benefits in the long-term interest of consumers); and
- includes proposed RIT-T reopening triggers, for feedback from stakeholders.

Overall, a key purpose of RIT-T framework is to provide interested stakeholders the opportunity to review the analysis and assumptions during the assessment and have certainty and confidence that the preferred option at the end of the process has been robustly identified as optimal.

This consultation is in addition to, and complements, the engagement ElectraNet is undertaking with affected communities and other stakeholders, which is detailed in section 4.5 below.

Alongside this PADR, ElectraNet has also published the NPV results workbooks, a wholesale market modelling report and a report by KPMG on the bushfire risk analysis undertaken.

1.2 Submissions and next steps

ElectraNet welcomes written submissions on materials contained in this PADR. In particular, we would like to hear from proponents of new spot load developments in the Mid North, Eyre Peninsula and Upper North regions of South Australia regarding the status of their proposals given the importance of these developments to the outcome of this RIT-T.

Submissions are due on 11 June 2026.

Submissions should be emailed to our Planning team via consultation@electranet.com.au. In the subject field, please reference 'Northern Transmission Project – PADR feedback'.

The PACR is expected to be published by December 2026. The PACR will take into account any updated analysis contained in AEMO's 2026 ISP, due to be published in June 2026.

[32] In particular, the collective generation from the Riverland, Mid North SA, Yorke Peninsula REZ and net inflows from EnergyConnect, Heywood and Northern SA (the 'MN1 constraint' in the draft 2026 ISP).

2 The identified need

The focus of the options considered in this PADR is to increase the power system capability of the Mid North region of the South Australian transmission network. Specifically, each option has been designed to:

- support the expected increase in renewable generation north of Adelaide to support growing demand in Adelaide;
- ensure adequate network capacity and supply for large industrial loads (LILs); and
- alleviate congestion on renewables from the Mid North to the rest of the NEM.

These three drivers form the 'identified need' in the ISP.[33]

While this project was first identified as an 'actionable ISP project' in the 2024 Integrated System Plan (ISP), the draft 2026 ISP states that it is subject to ongoing analysis and stakeholder engagement to confirm its status, due to uncertainty on input assumptions that could impact the benefits.[34]

We consider that the assessment presented in this PADR demonstrates the value that NTx provides and supports it continuing to be included as an actionable ISP project in the 2026 ISP.

This section:

- presents an overview of the existing transmission network (section 2.1);
- outlines the changing landscape that is affecting the South Australian electricity transmission network, and more directly its impact on the Mid North region (section 2.2); and
- describes the existing congestion on the transmission network (section 2.3).

These three sections form important background and context for each of the three key components of the identified need, which are then outlined further in sections 2.4-2.6 below.

2.1 Overview of the existing network

The Mid North region is one of ElectraNet's seven regional networks in South Australia. It is the part of our transmission network to the north of Metropolitan Adelaide extending up to Davenport, where the Eyre Peninsula and Upper North regions begin. The network serves loads on Eyre Peninsula, far north mining operations and the Adelaide load centre which accounts for around 65% of the state's energy consumption.

The Mid North region currently has four 275 kV double circuit transmission lines along the Davenport to Metropolitan Adelaide corridor, which connect a number of renewable energy developments (primarily wind farms) and grid-scale Battery Energy Storage Systems (BESS), as well as the Mintaro and Hallet dispatchable gas generators.

[33] AEMO, *draft 2026 ISP Appendix 5 – Network Investments*, December 2025, p. 54. & AEMO, *2024 ISP Appendix 5 – Network Investments*, June 2024, p 40. The project was referred to as the 'Mid North South Australia REZ Expansion' in the 2024 ISP.
[34] AEMO, *draft 2026 ISP*, December 2025, p. 15.

The Mid North transmission network was designed to export coal from Port Augusta to Adelaide. At its peak, Port Augusta supplied 780 MW of coal generation into Adelaide. The last coal-fired power station retired in 2016.

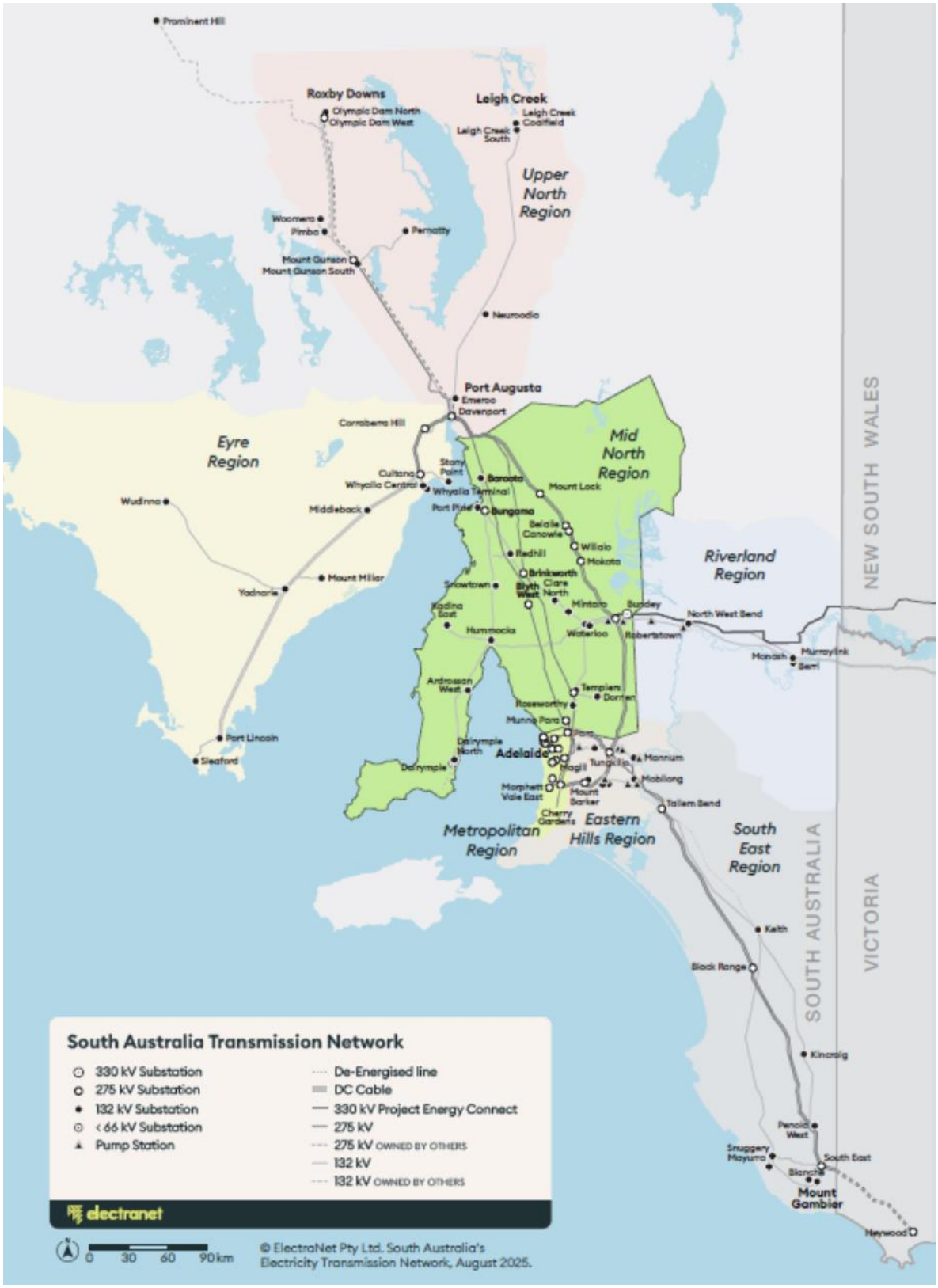
The Mid North region now also connects to two interconnectors in the NEM – namely:

- Murraylink, which connects South Australia to Victoria and has a maximum import and export capacity of 220 MW and 150 MW, respectively; and
- Project EnergyConnect, which connects South Australia to NSW and currently has an import/export capacity of 150 MW which will progressively increase to 800 MW once stage 2 construction is completed and inter network testing occurs over 2027.

Figure 1 provides an overview of the existing transmission network in the Mid North region, shown in light green, as well as the rest of ElectraNet's electricity transmission network in South Australia.

The Mid North region now transmits electricity from around 2,200 MW of installed wind generation capacity to Adelaide and the state's interconnectors (which is expected to increase to 3,200 MW by 2030). Increasingly, BESS have located into the Mid North region with 1,000 MW of operational and anticipated capacity currently, which is forecast to increase to 2,500 MW by 2030. Both intermittent wind supply and dispatchable BESS will exceed the historical utilisation of this corridor and the capability to transmit the dispatchable capacity at full utilisation into Adelaide.

Figure 1: Mid North transmission region (shown in light green)



2.2 The transformation of the South Australian network

South Australia has undergone a rapid and globally significant transformation of its electricity system, shifting from a fossil-fuel-dominated grid in the early 2000s to one now characterised by extremely high levels of renewable energy penetration.

The State has more than 3,400 MW of grid-scale wind and solar and more than 3,000 MW of rooftop solar PV, operating within a system with relatively modest average demand of around 1,400 MW. Renewable generation has increasingly met local and state demand (including periods of 100% renewable supply) since 2021 and, in 2025, renewables supplied over 75% of annual electricity consumption, ahead of South Australia's target of 100% net renewable electricity by 2027.

This transformation is now moving to a new phase of electricity demand growth driven by economic development and electrification. State and Federal decarbonisation policies, combined with South Australia's strong renewable resource base and mineral endowment, are attracting electricity-intensive industries such as minerals processing, green manufacturing, data centres, water infrastructure and defence-related developments. Many of these projects are large, geographically dispersed and discrete in timing, creating step changes in load that materially affect transmission planning requirements. This load is centred on greater Adelaide and the Upper Spencer Gulf region, with other load centres emerging around Bundey and the southeast.

Coal powered generators retired fully from South Australia in 2016. Recent retirements of gas in the metropolitan region have been balanced by new gas generation. However, with the further anticipated retirement of metropolitan gas generation, there will be an increasing reliance on dispatchable power outside of the metropolitan region and even from interstate meaning that South Australia's next stage of decarbonisation and economic development is increasingly a transmission challenge. Delivering a resilient, high-capacity transmission backbone is essential to translate the State's renewable advantage into secure, low-cost electricity for households, businesses and new industry.

As the State's principal Transmission Network Service Provider, ElectraNet plays a central role in enabling this growth while maintaining reliability and affordability. Our high-voltage network spans around 7,000 km and connects geographically dispersed renewable resources to concentrated load centres, particularly in Greater Adelaide.

2.2.1 Emerging demand hotspots across South Australia

South Australia's demand growth is expected to be significant and concentrated in specific locations, requiring transmission planning to carefully match where and when new demand emerges and the nature of those loads. Planning must balance being proactive—so network capability is ready in time—with a staged, cautious approach that reflects uncertainty in future projects.

Customer engagement and planning have identified several key demand hotspots, with both expanding existing load centres and new step-change developments driving the need for significant new transmission developments.

South Australia's electricity demand growth is expected to be significant, unevenly distributed, and diverse in nature. Greater Adelaide remains the dominant load centre, with demand projected to rise by 25–35% over the next 10–15 years due to population growth, electrification

and electric transport. Further developments of data centres, and defence-related expansion will increase this further. The Upper Spencer Gulf and northern regions are anticipated to see large, step-change increases in demand driven by industrial transformation such as green metals, minerals processing and desalination, with major implications for new transmission capacity. The Eyre Peninsula is emerging as both an industrial and renewable energy region, enabled by the Eyre Peninsula Link and requiring expanded transmission pathways to support staged load growth.

Other regions such as the Mid North and South East are also expected to host material new activity, storage and large loads like magnetite mining, forestry and data centres, increasing the need for a network capable of efficiently moving energy between dispersed generation zones, Adelaide, and new regional demand hubs.

2.2.2 South Australia is a leader in renewable energy

South Australia's economic growth depends on expanding renewable generation—particularly wind—supported by storage and firming, with most new generation located outside Adelaide, increasing reliance on transmission to deliver power to load centres and enable exports during surplus periods.

The Mid North is South Australia's primary renewable hub, with strong wind resources, growing utility-scale solar and batteries, and direct access to the main 275 kV transmission backbone. Ongoing expansion is driving the need for network reinforcement to manage congestion and fully utilise high-quality resources.

The Eyre Peninsula is rapidly emerging as a renewable and industrial region. Commissioning of the Eyre Peninsula Link in 2023 significantly improved reliability and unlocked capacity, enabling new wind, solar, storage and industrial loads, with the ability to export surplus energy to the broader system. Additionally, the SA government has released two large renewable areas at the top of the peninsula. On 30 March 2026, the South Australian government invited tenders for these release areas.[35]

South Australia's future renewable supply will be increasingly dispersed, and realising its full value depends on a transmission network that can efficiently connect new generation and storage, deliver power securely to growing load centres, and enable exports during surplus periods to minimise curtailment and improve overall system efficiency.

Flexible firming in the generation mix

South Australia's electricity system is transitioning away from major gas plants around Adelaide that are progressively retiring over the next decade. The South Australian government is seeking to provide additional long-duration firm capacity with the Firm Energy Reliability Mechanism (FERM) with tenders expected to be first awarded by May 2026. The location of this capacity is at present unknown. Our current expectation is that over time there will be a reduction in local firm generation in Greater Adelaide, increasing reliance on transmission to supply greater Adelaide. Replacing both energy and critical system services requires a portfolio approach, with grid-scale

[35] https://www.energymining.sa.gov.au/industry/hydrogen-and-renewable-energy/hydrogen-and-renewable-energy-act/release-areas/call-for-tenders

batteries already playing a growing role and new fast-start dispatchable resources being considered at strategic locations where electricity and gas infrastructure intersect.

2.3 Overview of the existing congestion

South Australia's transmission network is evolving under the combined pressures of concentrated renewable development, changing power flows and emerging load growth. The existing 275 kV network was not designed for the current and forecast conditions of sustained high renewable penetration, material two-way flows and large new loads in regional areas. As a result, congestion is increasingly structural: it reflects the physics and security requirements of the network, rather than a limited number of isolated constraint events.

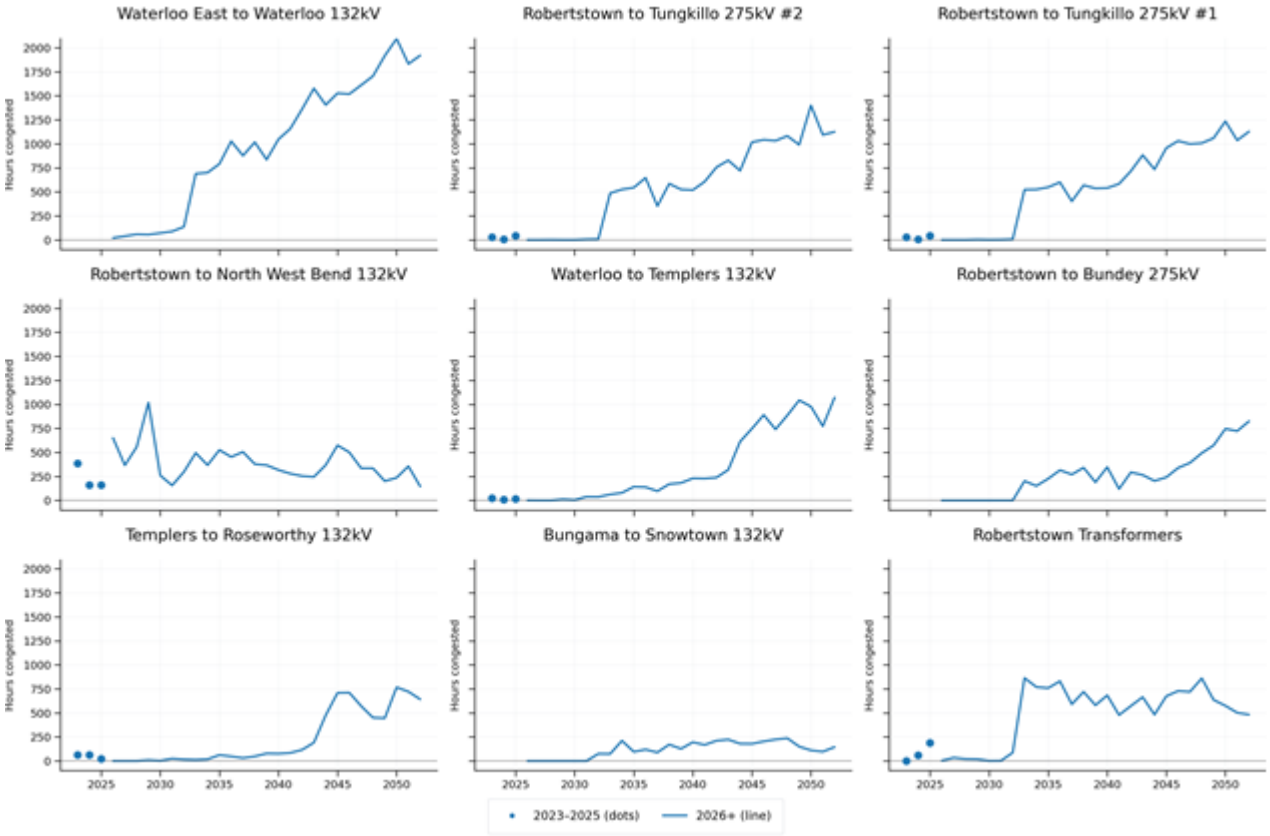
A practical indication of current capability is provided by today's transfer limits. Practical transfer capability into Greater Adelaide is around 1,100 MW, while practical transfer capability into the Upper Spencer Gulf (Whyalla) is around 450 MW. These practical limits are constrained by a combination of thermal limits and system security requirements, including voltage stability. As northern variable renewable output and regional loads rise, these limits become binding more frequently and for longer durations.

The principal 275 kV corridor running from Davenport (near Port Augusta) to Adelaide is the backbone of the South Australian grid, linking resource rich northern regions to the load rich south. During periods of high wind and solar output in the north, these lines can reach capacity and require renewable output to be curtailed to maintain system security.

As local dispatchable plant retires within Adelaide, the corridor will shoulder more of Adelaide's supply, increasing the severity and consequences of congestion unless new capacity and alternative pathways are developed.

Under central planning scenarios, our studies indicate a tipping point around 2030 beyond which congestion hours on key interfaces into Adelaide increase materially and, without augmentation, would restrict access to lower cost renewable supply leading to higher wholesale prices. Figure 2 shows these congestion increases for some of the key network elements that are part of the supply to metropolitan Adelaide.

Figure 2: Current and forecast congestion at key ElectraNet network elements



Constraints are also emerging in the northern regions. While the northern terminus of the main 275 kV system is at Davenport, regional radial networks extend to key regions such as the Eyre Peninsula and Olympic Dam. These arrangements are not designed to support the scale of new industrial demand signalled in the Upper Spencer Gulf and continue to supply Adelaide, nor to support the efficient integration of new renewable supply at the scale anticipated under high growth pathways. Addressing this requires a step change in transmission capability that can both supply new loads and provide efficient pathways for renewable energy to reach the relevant demand centres.

ElectraNet anticipates significant growth in large industrial loads in South Australia, requiring substantial expansion of renewable energy generation to supply them. These developments are expected to materially alter power flows and network constraints over the next decade.

Figure 3 illustrates the level of congestion[36] expected by 2035 assuming no network backbone augmentations are undertaken. The analysis is based on the thermal limits of the existing network under current three-band operational limits and step change scenario. Without augmentation, the Mid North is expected to experience significant congestion, particularly on the lower sections of the western 275 kV circuits between Para and Davenport. This would directly affect renewable generators in the region, leading to output curtailment and potentially

[36] Congestion is shown as the estimated number of hours in a year that the transmission line will reach its capacity limit and it is not able to transfer any additional power.

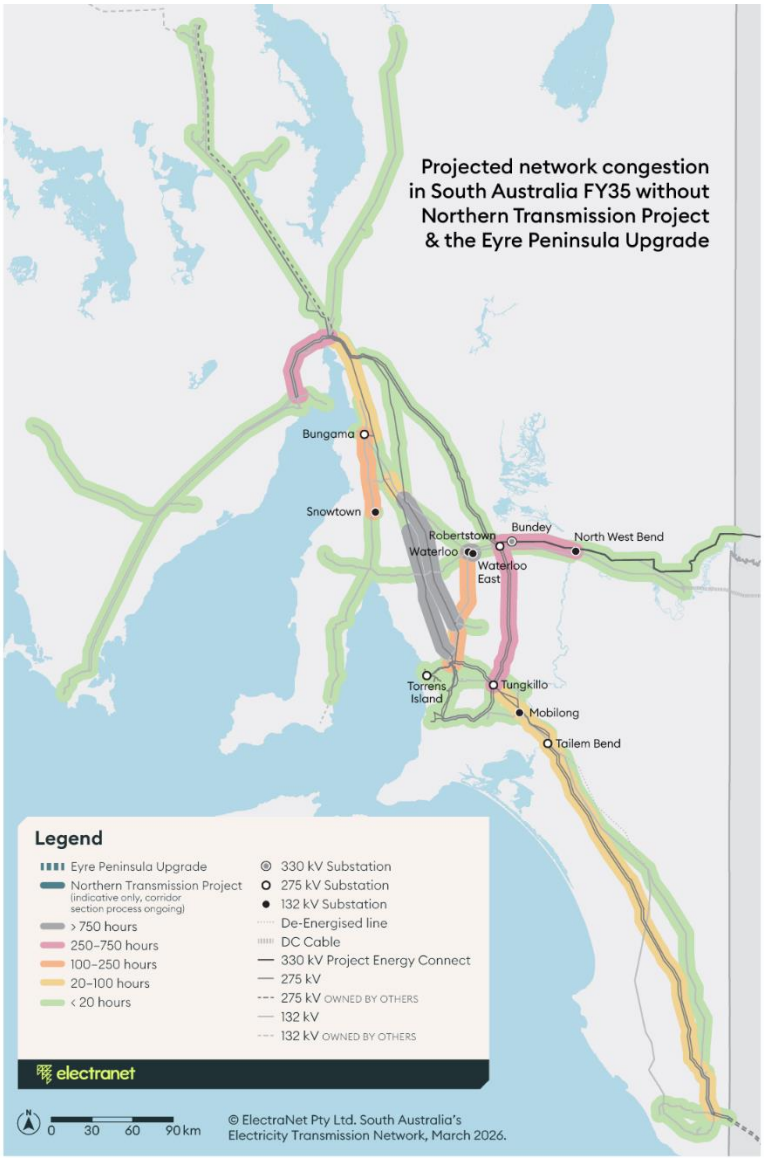
requiring surplus installed generation or increased reliance on imports, which may discourage future renewable connections.

Supply to metropolitan Adelaide would also be increasingly constrained, as the main circuits feeding Para and Tungkillo are expected to operate under congestion. This would limit the amount of power deliverable to the city and could necessitate the continued operation of gas-fired generation within Adelaide. In addition, congestion on circuits connecting to the interconnectors would restrict export and import capability below interconnector ratings.

These impacts are expected to be exacerbated by changes in dispatch patterns resulting from increased renewable generation and the establishment of Project EnergyConnect between South Australia and New South Wales. Together, these factors will significantly reshape network flows and constraints over the coming decades.

Network congestion will increase prices for South Australian customers by restricting access of lower-cost generation to existing and emerging load centres. Consequently, higher-cost generation will be dispatched in place of lower-priced renewable energy, resulting in increased wholesale prices.

Figure 3: Estimated network congestion for 2035 without NTx



2.4 NTx supports growing demand in Adelaide to be supplied by expected increase in renewable generation north of Adelaide

General electricity demand in Metropolitan Adelaide is expected to increase by 25-35 per cent over the next 10-15 years.[37] This is primarily due to:

- population expansion adding to general demand – the population of the Greater Adelaide Planning Region is projected to grow by over a half a million residents by 2050;[38] and
- renewable energy policies in South Australia driving rapid electrification of homes, businesses, and transport – for example, South Australia's target for 100 per cent renewable electricity generation by 2027 is accelerating household and commercial electrification, and the Electric Vehicle Action Plan aims to have taxi and ride share fleets in metropolitan Adelaide fully electric by 2030.[39]

In addition to this general growth in electricity demand, included in AEMO's and SA Power Networks demand forecasts, we have identified the following future demand:

- defence sector growth concentrating major military manufacturing and technology development in Adelaide – South Australia led the country in defence industry expansion in 2023-24,[40] with Adelaide set to drive much of the expected continued growth through major projects such as the Hunter-class frigate program at Osborne Naval Shipyard; [41]
- a number of data centres are expected to be commissioned in coming years, all of which represent energy-intensive connections. Two major data centres opened in Adelaide in 2024 alone.[42]

In order to meet this anticipated load growth in Adelaide, it is expected that a significant amount of new renewable generation capacity will be commissioned in the regions north of Adelaide, where there are high-quality wind and solar resources. The proximity of these resources makes them well-placed to supply the increasing electricity demand in Adelaide.

---

[37] This projection is based on forecasts provided by SA Power Networks at the distribution level. It does not include any data centre loads or other prospective LILs.
[38] Population projections by PlanSA. Available at https://plan.sa.gov.au/state_snapshot/population/population-projections, accessed on 15 May 2025.
[39] South Australia's Electric Vehicle Action Plan. Available at https://www.energymining.sa.gov.au/__data/assets/pdf_file/0009/609390/DEM-Electric-Vehicle-Action-Plan.pdf, accessed on 15 May 2025.
[40] ABS, *Australian Defence Industry Account, experimental estimates*, available at: https://www.abs.gov.au/statistics/economy/national-accounts/australian-defence-industry-account-experimental-estimates/2023-24.
[41] Hunter Class Frigate project details. Available at https://www.defence.gov.au/defence-activities/projects/hunter-class-frigate, accessed on 15 May 2025.
[42] NEXTDC's A1 Adelaide in city and DCI Data Centres' ADL02 in western suburbs. Available at https://adelaideaz.com/articles/new-data-centres---a1-adelaide-in-city-and-adlo2-in-western-suburbs---big-boost-in-2024-for-adelaide-s-digital-infrastructure#:~:text=Images per cent20courtesy per cent20NEXTDC per cent20and per cent20DCI,digital per cent20hub per cent20for per cent20technology per cent20innovation, accessed on 15 May 2025.

For example, the Goyder Renewables Zone represents a significant hybrid renewable energy development near Burra and Robertstown in the Mid North region. The project comprises two components (both of which are to be delivered in stages), Goyder South and Goyder North, combining wind, solar and battery storage to deliver substantial renewable energy. Goyder South Stage 1 (which has now been commissioned) and Goyder North (2 x 300 MW). Goyder Renewable Zone has the capacity to generate over 1.5 TWh annually by the end of 2028.[43]

Supporting the uptake of renewables in the Mid North region, is a significant pipeline of new BESS. For example, in September 2024, South Australia secured significant renewable energy commitments through the Federal Government's Capacity Investment Scheme (CIS), with 530 MW of BESS (and 230 MW of solar generation) awarded. These projects include the following systems in the Mid North region, which together will provide close to 2 GWh of energy capacity:[44]

- the Solar River project with a BESS (123 MW/225 MWh) paired with the Solar River 255 MW solar farm;
- Bungama Solar project with a BESS (150 MW/300 MWh) in conjunction with Solar solar farm (280 MW);
- Clements Gap BESS (60 MW/120 MWh); and
- Hallett BESS (50 MW/200 MWh).

In addition, in September and October 2025, it was announced that a further three BESS, totalling 3,000 MWh of dispatchable capacity, were approved for the Mid North region under the Federal Government's CIS.[45] As of January 2026,[46] AEMO lists 1,650 MW of storage capacity that is either 'committed' or 'anticipated' in the regions north of Adelaide (10 projects), with more than 8,500 MW in additional 'proposed' projects (35 projects).[47]

Similarly, there are more than 1,000 MW of renewable energy, wind or solar projects that are either noted as 'committed' or 'anticipated' by AEMO in the regions north of Adelaide (4 projects), with more than 3,700 MW in additional 'proposed' projects (18 projects). It is expected that the interest in new projects will increase with the SA government auctions for the Gawler Ranges East and Whyalla West release areas.[48]

[43] The Goyder Renewables Zone will be developed across five sequential stages over 18-30 months each: three stages for Goyder South (Stage 1 comprising 1A and 1B, plus stages 2 and 3) and two stages for Goyder North, with Goyder South stages 1A and 1B currently under construction and remaining stages in development and approval phases. See: Goyder Renewables Zone, available at https://goyderenergy.com.au/.

[44] Capacity investment scheme, closed CIS tenders. Available at https://www.dcceew.gov.au/energy/renewable/capacity-investment-scheme/closed-cis-tenders, accessed on 15 May 2025.

[45] This does not include the results of Tender 5, which had not been released when this PADR was finalised. https://www.dcceew.gov.au/about/news/cis-boosts-australias-renewable-energy-future & https://www.dcceew.gov.au/about/news/cis-tender-4-deliver-6-6gw-clean-energy

[46] AEMO, *NEM Generation Information January 2026*.

[47] AEMO, *NEM Generation Information January 2026*.

[48] https://energymining.sa.gov.au/industry/hydrogen-and-renewable-energy/hydrogen-and-renewable-energy-act/release-areas/call-for-tenders

The substantial number of proposed renewable and BESS projects in the Mid North Region supports the continuing identification of the expected increase in renewable generation north of Adelaide as a key driver for NTx.

The capacity of the four existing 275 kV double circuit transmission lines along the Davenport – Metropolitan Adelaide corridor currently constrains how much renewable energy can flow from the generation sources in the north through to Adelaide in the south. While this is currently the case, the impact of these constraints will increase in severity as dispatchable gas generation capacity retires in South Australia, e.g., when Torrens Island B Power Station and Osborne Power Station retire.

The options assessed in this PADR all provide additional network capacity to support the transfer of renewable energy from new renewable generation north of Adelaide to the Adelaide Metropolitan region, providing significant expected market benefits in the wholesale market modelling. Moreover, and as noted by AEMO in the draft 2026 ISP, we consider that NTx could deliver increased benefits if new generation and storage cannot, or does not, connect in areas considered optimal under the base case (i.e., the areas determined optimal in the wholesale market modelling).[49]

While AGL has recently agreed to extend the retirement of some of the units at Torrens Island B by two years, we note that this does not affect the expected preferred option for this RIT-T as the new retirement date (30 June 2028) is ahead of the earliest commissioning date for the credible options.

2.5 NTx ensures adequate network capacity to supply new LILs

The current transfer capacity along the Mid North corridor restricts the capability of the existing transmission network to meet growing industrial demand.

There has been significant growth in LILs[50] across South Australia in recent years. For example: [51]

- the proportion of the state's total load attributable to these loads doubled between 2009/10 and 2024/25 (from 9 per cent to 18 per cent); and
- these loads grew by over 5 per cent on average annually during the past fifteen years (and nearly 7 per cent in 2024).

In its electricity demand forecasts, AEMO considers all customers connected directly to the transmission network as a LIL. In the 2025 Electricity Statement of Opportunities (ESOO), AEMO projected that LILs in South Australia would:[52]

[49] AEMO, *Draft 2026 ISP*, Appendix A6. Cost Benefit Analysis, December 2025, p. 112.
[50] A large industrial load is a non-residential electrical load large enough that requires a direct connection to the high-voltage transmission network.
[51] 2025 Transmission Annual Planning Report, p. 34. Available at https://electranet.com.au/wp-content/uploads/2025/06/250516_TAPR_FINAL-1.pdf
[52] These numbers are derived from AEMO's Electricity Annual Consumption data, using the following parameters: publication ESOO 2025 (version 2025-08-21), operational (sent out) category, South Australia region, and step change scenario. Available at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal, accessed 22 July 2025.

- continue to grow steadily over the next 25 years, increasing from 3.52 TWh in 2026 to 7.32 TWh by 2050 (more than doubling over this period); and
- in the near term, grow by approximately 89 per cent in the next five years (from 3.52 TWh to 6.66 TWh between 2025 and 2030), with a reduced continued steady growth until 2030, when there is a large step of approximately 2.88 TWh.

AEMO considered a sensitivity in the 2024 ISP related to increases in LILs in South Australia. This sensitivity included an additional 13 TWh of load on the Eyre Peninsula and Upper North by 2030, increasing to 16 TWh by 2050, which found that the net benefits of NTx increased with the additional industrial load developments.[53] South Australian Department of Energy and Mines has identified 10 TWh of load growth concentrated on the Upper Spencer Gulf and Eyre Peninsula.[54]

While it is not clear what will be included in the 2026 ISP, we note that the draft 2026 ISP did not investigate a sensitivity of this type meaning that AEMO did not consider the potential additional benefits that NTx would provide if demand was higher than projected (and in the order of the 16 TWh tested in the 2024 ISP). However, we anticipate that AEMO will again investigate a high demand sensitivity in the 2026 ISP that will test the value NTx with higher growth.

In parallel with developing its inputs and assumptions for the 2026 ISP, AEMO consulted on its demand forecasting methodology. Following this consultation, AEMO has updated its demand forecasting approach, and in particular its treatment of prospective LILs.[55] This updated approach underpins AEMO's most recent demand forecasts, as published in the 2025 ESOO.

Under its updated demand forecasting approach, AEMO now also considers prospective LILs including those at a 'proposed' stage, identified through information requests, other industry engagement and media searches. For all prospective projects, AEMO assigns a project status – including committed, anticipated or proposed loads - based on the likelihood of the project being developed. 'Proposed projects' are projects not classified by AEMO as committed or anticipated, and are identified explicitly on the basis of:

- the project is at least at application stage of the connection process, or
- the project has not yet reached application stage of the connection process but is assessed as likely, that is, it either:
    - aligns with government policy, or
    - is of state significance, or
    - is otherwise assessed as likely based on the LIL survey process, NSP information requests or market research.

Following the update to its demand forecasting methodology, AEMO's demand forecasts for South Australia in its 2025 ESOO have increased, and now incorporate anticipated load growth due to a number of additional LILs in South Australia in both its Step Change and Accelerated Transition forecasts.

ElectraNet strongly supports the consideration of prospective LILs in the demand outlook for planning purposes in South Australia, given the long lead-time required to progress

[53] AEMO, *2024 ISP*, Appendix 6, p. 109.
[54] SA DEM, *Draft 2026 ISP submission*, 2026.
[55] AEMO, *Forecasting Approach – Electricity Demand Forecasting Methodology*, July 2025, section 2.1.

transmission investment to accommodate this load. We anticipate substantial industrial demand growth in South Australia, stemming from the unprecedented levels of enquiry activity we have experienced from large industrial customers

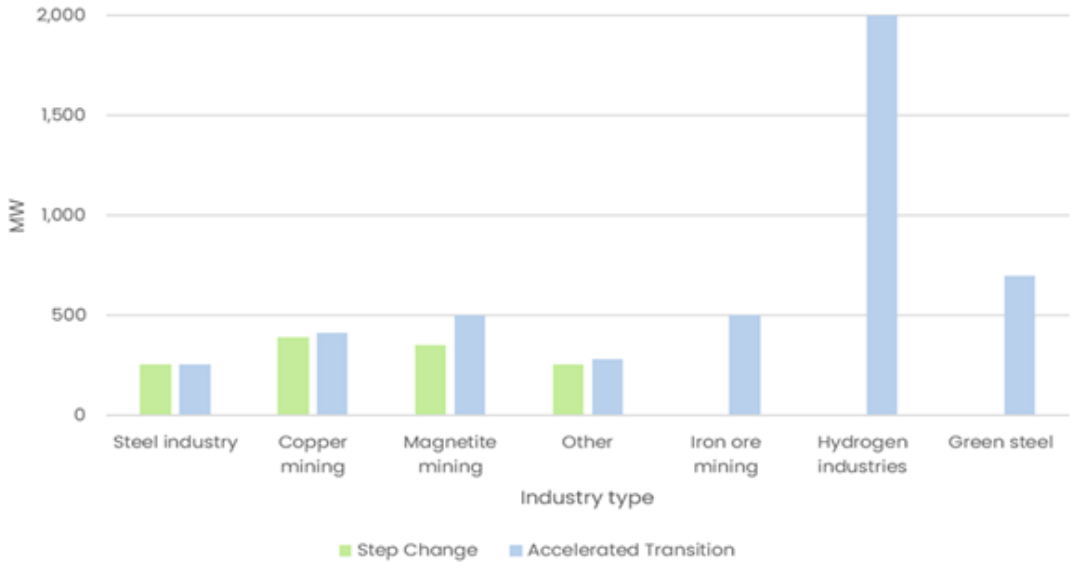
As outlined in section 5.1, we have applied the 2025 ESOO demand forecasts in the analysis for this PADR, consistent with the draft 2026 ISP. However, based on enquiry activity, and the overlap with specific policy initiatives being pursued by the SA Government, we strongly expect that load growth in South Australia including prospective LILs will be higher than the forecast by AEMO in the 2025 ESOO. Indeed, we have received several new connection enquiries in recent months, which have not been considered by AEMO in developing the demand forecasts in the 2025 ESOO.

As an example of the increasing number of LIL connection prospects:

- Over the ten-year period spanning 2012 to 2022, ElectraNet received only one enquiry from a single large-scale industrial operation (seeking approximately 50 MW of capacity); while
- in contrast, ElectraNet is currently engaging with 38 individual large industrial customers exploring direct connections, and these customers are planning more than 65 individual projects (i.e., many customers are seeking connections across multiple developments), with probable interest of around 2,500 MW of additional load by 2035, that could reach 5,500 MW if other less probable LILs were to connect – these projects include major developments relating to mining and green energy and steel, as well as other industries.

Key types of LIL included in AEMO's 2025 ESOO are summarised, in aggregate,[56] in Figure 4 below for the Step Change and Accelerated Transition load forecasts. The AEMO 2025 ESOO Slower Growth load forecast includes no LIL demand.

Figure 4: Composition of LIL in the Step Change and Accelerated Transition scenarios



Note: the total potential capacity for hydrogen industries is above 8,000 MW, but the scale on the graph has been reduced to facilitate the comparison between industries.

[56] All loads have been aggregated in order to preserve confidentiality.

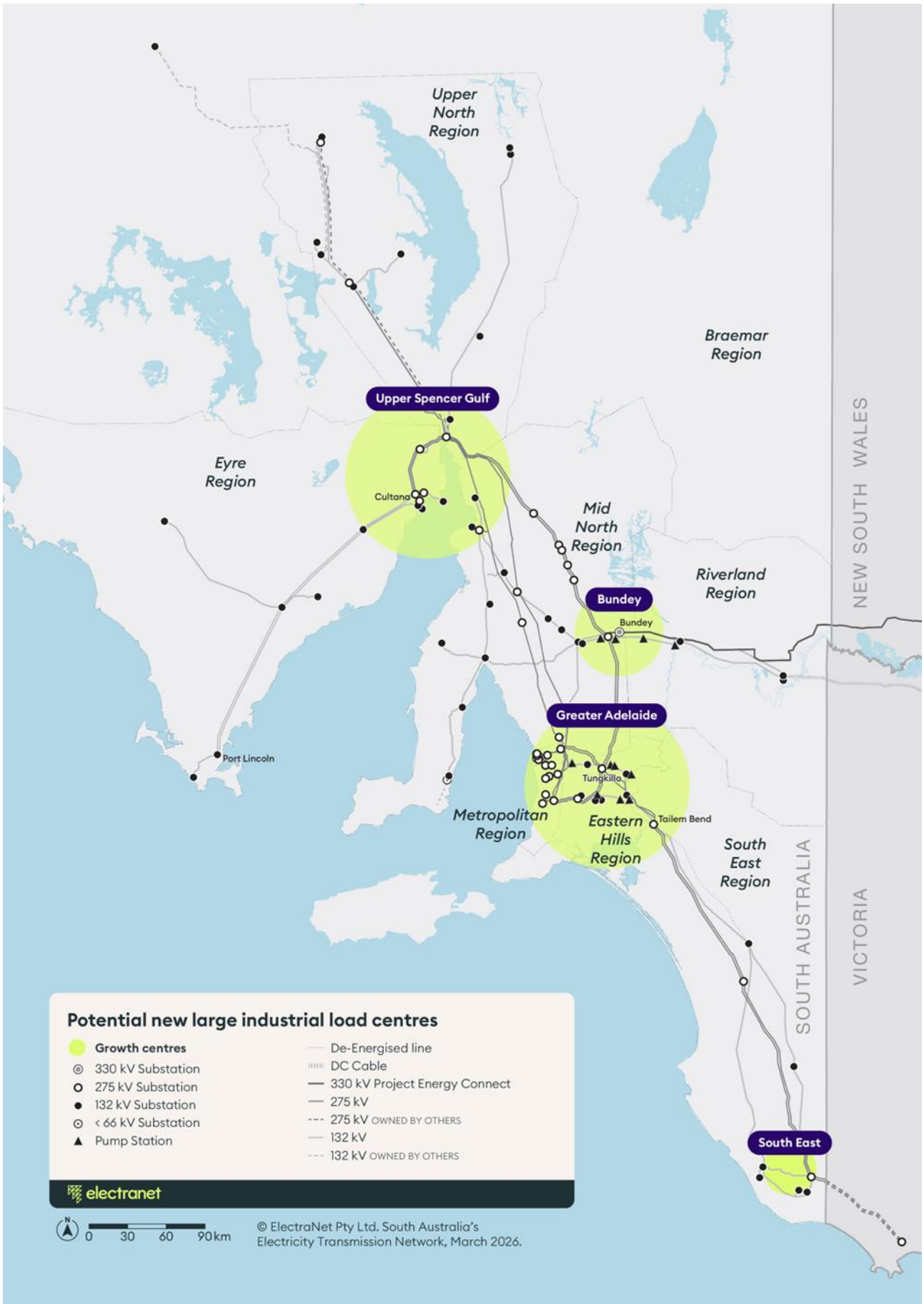
Figure 5 below shows the location of ElectraNet's primary current LIL connection interest. This is not exhaustive of all interest.

Figure 4 does not include any data centre loads, and we note that AEMO has only included one data centre load (near Yadnarie) in its 2026 ISP Step Change and Accelerated Transition scenarios (and none in its Slower Growth scenario).

Like other parts of the NEM, ElectraNet is in discussions with several proponents seeking to connect large data centres to the transmission network. These proposals typically involve initial loads of around 300 MW within the next few years, with rapid ramp-up to loads exceeding 1 GW within a short period thereafter. While there is uncertainty regarding which of these projects will proceed, the connection of even a single data centre would represent a material increase in South Australia's electricity demand.

As noted above, existing transfer capacity limitations in the Mid North corridor constrain the ability of the transmission network to accommodate this emerging industrial demand. These constraints are already driving adverse market impacts across South Australia's transmission network and are expected to intensify as dispatchable gas-fired generation progressively retires.

Figure 5: Current LIL connection interest[57]



The options assessed in this PADR will directly address this constraint by increasing the transfer capacity of the corridor, thereby ensuring energy security for existing industrial operations whilst also enabling new LIL connections. For existing industrial customers, this means reduced frequency and duration of load shedding events, while for new customers (e.g., in the mining and green steel sectors), it provides the required transmission capacity to enable connection.

In light of the realistic potential for substantial, additional LILs to locate in and adjacent to the Mid North region, we have included a sensitivity in this PADR to investigate the impact of a higher South Australian load forecast compared with that in the 2025 ESOO (see section 7.5.2).

2.6 NTx alleviates congestion on renewables from the Mid North being able to export to the rest of the NEM

As South Australia continues to increase renewable energy capacity to meet the South Australian Government's target of 100 per cent renewables by 2027, periods of surplus renewable generation are becoming more frequent (and substantial), increasing the importance of export capacity to neighbouring states.

All options assessed in this PADR increase the network capacity at Bundey in the Mid North region of South Australia, which is near where the new Project EnergyConnect interconnector joins the network (at Robertstown). The options assessed in this PADR are expected to complement Project EnergyConnect and facilitate surplus renewable generation output from South Australian renewables being exported to New South Wales and Victoria during high renewable generation periods in South Australia (and vice versa).

There are a number of network limitations that are currently restricting flow into Adelaide. These limitations are on both the 275 kV backbone and parallel 132 kV network supplying loads. The impact on dispatch of renewable generators will increase over time.

Under the Step Change scenario adopted in this PADR (ie, that defined in section 5.1), some of the key constraints that will restrict flows on the 275 kV network include the two circuits from Robertstown to Tungkillo, where we estimate congestion will increase to 100-400 hours per year from 2033 and to 400-1,000 hours per year from 2043.

On the 132 kV network, under the same assumptions, we estimate that for:

- the circuit from Waterloo East to Waterloo, congestion will increase to more than 400 hours per year from 2033, to more than 1,000 hours per year from 2042 and to 1801 hours by 2050;
- the circuit from Waterloo to Templers will start to see congestion from 2028, increasing to more than 100 hours per year from 2033, 200-400 hours per year from 2038, and more than 1000 hours per year from 2045;
- the circuit from Templers to Roseworthy will start to see congestion from 2028, increasing to 500 to 1,000 hours per year from 2044;
- the circuit from Bungama to Hummocks will start seeing congestion from 2032, increasing to around 100 hours per year from 2038; and

[57] ElectraNet, *Transmission Annual Planning Report*, 2026.

- the Robertstown 275/132 kV transformers, which show 2 hours of congestion at 2026, will increase to around 500 hours per year by 2033.

Under the Accelerated Transition scenario, a large number of 275 kV and 132 kV circuits around the Mid North and the Metropolitan Adelaide areas would experience extreme congestion due to the larger demand considered in this scenario.

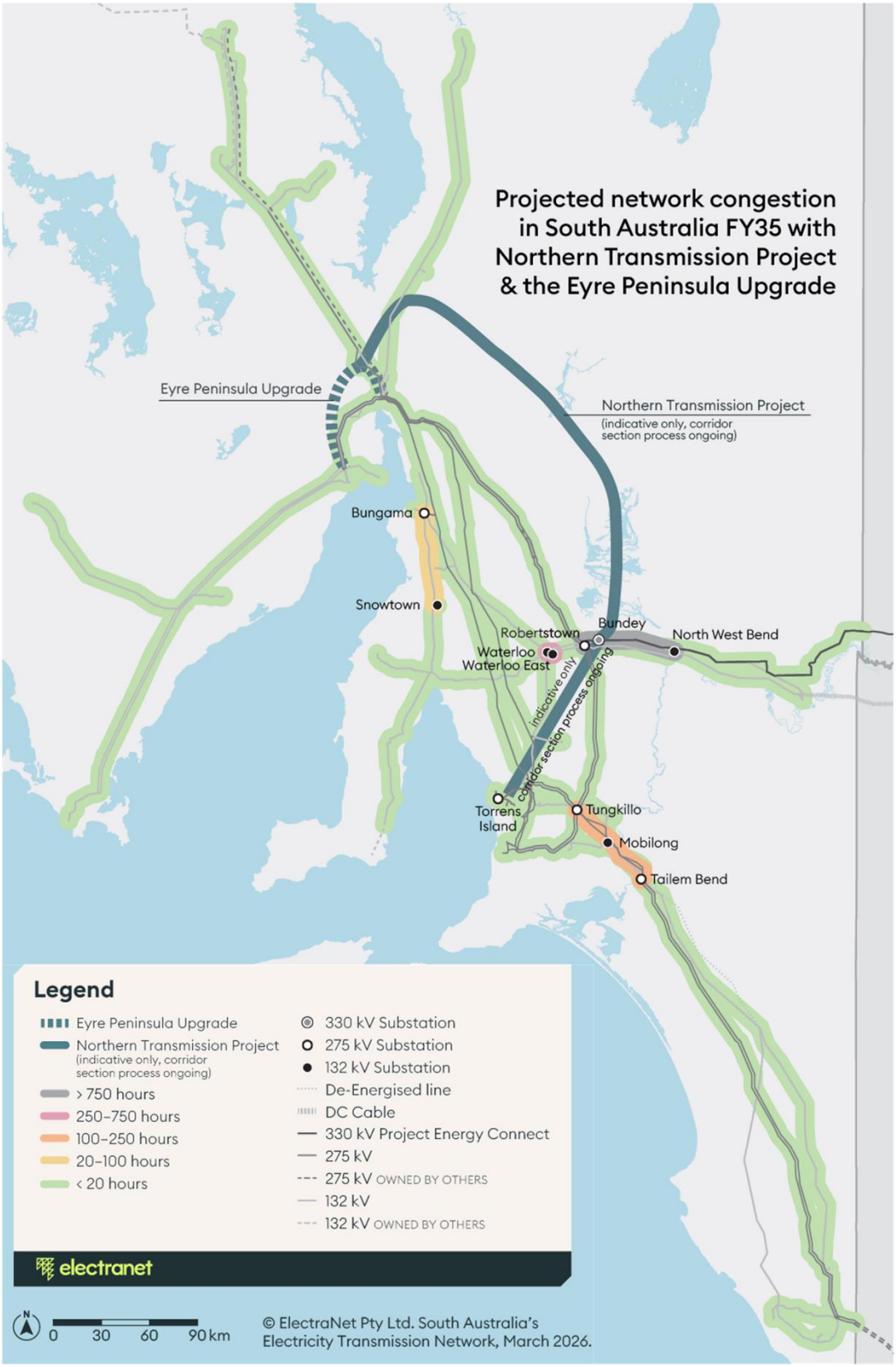
ElectraNet is also forecasting that limitations between Victoria and New South Wales will frequently be reached without action, thereby preventing renewables from the Mid North reaching the rest of the NEM. However, alleviating this congestion is outside the scope of this RIT-T and is expected to be considered by AEMO in the 2026 ISP.

The effect of this congestion will be to increase prices for customers in South Australia, as lower cost available generation will not have access to existing or emerging load centres. As a result, lower price renewable generation will be replaced by more expensive generators and prices will increase.

Figure 6 illustrates the anticipated level of network congestion assuming the NTx and Eyre Peninsula Upgrade augmentations are delivered. The analysis adopts the same assumptions as those used for Figure 3 in a preceding section. A comparison of the two figures demonstrates how these projects alleviate congestion, with NTx removing constraints in the Mid North and metropolitan Adelaide. Some network constraints remain, which are expected to be addressed by future projects.[58]

[58] ElectraNet Transmission Annual Planning Report 2026

Figure 6: Expected network congestion for 2035 with NTx and EP Upgrade



3 Non-network solutions consultation

In June 2024, AEMO called for non-network options for the Mid North South Australia REZ Expansion project.[59] Responses were due on 18 September 2024, and AEMO received submissions from the following parties:

- a confidential proponent of a BESS in the Mid North region;
- a confidential proponent proposing to combine a BESS with a solar PV facility in the Mid North region; and
- Lodestone Mines, who are developing a substantial magnetite mining complex in the Olary Flats region (approximately 330 km north-northeast of Adelaide).

ElectraNet has assessed whether each non-network proposal meets or is reasonably likely to meet the identified need. In doing so, we have contacted each submitter to understand their proposals further and we thank each party for their time and efforts to-date.

3.1 Confidential proponent of a BESS in the Mid North

The first confidential response proposes a BESS in the Mid North region with a charging capacity of up to 40 MW. Given its modest size and 132 kV connection point, this option may have the potential to defer some 132 kV works for NTx, but would not have a more material impact on the options considered in this PADR.

This BESS is not currently considered anticipated or committed under the criteria set out in the RIT-T. We have therefore assessed the full cost of this BESS (in line with the RIT-T framework) and find that these costs are not outweighed by the potential network deferral benefits (as well as a reasonable expectation regarding any wider wholesale market benefits).[60] We have therefore not included it in any of the options assessed in this PADR.

We understand that this project may receive external funding in the coming months that would reduce the effective capital cost of the project included in the RIT-T assessment.[61] We will re-examine the potential impact of this proposed non-network option on the timing of 132 kV works if this occurs ahead of the PACR, to identify whether adding this BESS into the scope of the preferred option may increase net market benefits.

We also understand that the network support funding this proponent would seek from ElectraNet is expected to be relatively modest, and likely consistent with what the AER would consider prudent and efficient, given the proponent intends to leverage other revenue streams for the project.

[59] AEMO, 2024 ISP Non network options consultation – Mid North South Australia REZ Expansion, June 2024, available at: https://aemo.com.au/consultations/current-and-closed-consultations/2024-isp-non-network-options-consultation-mid-north-south-australia-rez-expansion, accessed on 16 July 2025.

[60] While this assessment has been done on the Step Change scenario, we do not expect the conclusion to change if it were expanded to cover the other two scenarios.

[61] While this was mentioned in the NTx Progress Report as a reason for the PADR extension, we note that there has been no further development on this as at the date of this PADR.

3.2 Confidential proponent developing a BESS with a solar PV facility in the Mid North

The second confidential response outlines a significantly larger proposal combining a BESS with a solar PV facility in the Mid North region. With an expected final rating between 1,000 MW and 1,200 MW and a 275 kV connection, this proposal is not considered an alternative to the network solutions (and would not be able to defer the network investment being assessed). While we therefore consider that NTx would improve the operating environment for this larger BESS, it is not appropriate for it to form a part of the preferred option as it does not address the identified need.

3.3 Letter of endorsement from Lodestone Mines

The third submission came from Lodestone Mines, which did not propose a non-network option, but instead offered general endorsement for the project (particularly the proposed transmission line between Bundey and Davenport). While the company plans to initially operate using off-grid supply and behind-the-meter power solutions, it anticipates requiring a connection to the South Australian network within 5-7 years as operations expand. AEMO has included this load in the 2025 ESOO Step Change and Accelerated Transition load forecasts, which we have used for the analysis in this PADR (as outlined in section 5.1).

3.4 Submission to the consultation for the draft 2026 ISP – letter of endorsement from Magnetite Mines

Additionally, Magnetite Mines[62] made a submission to the consultation for the draft 2026 ISP, supporting NTx - North. The submission urges AEMO to factor in the benefits of NTx – North for South Australia's Braemar Iron Region. The company highlights that without NTx, their Razorback Iron Ore project and similar projects in the area would have to connect to Bundey, requiring a 130 km long high voltage transmission line.

Magnetite Mines urges AEMO to account for the forecast benefits for Braemar Iron Region operators (per NER clause 5.22.10(c)(1)), highlighting major capital and operating cost reductions plus efficiency gains and reduced environmental/social impacts. It argues these benefits should inform the 2026 ISP, so infrastructure aligns with Commonwealth and State economic development objectives.

[62] https://www.aemo.com.au/-/media/files/major-publications/isp/draft-2026/consultation-submissions/magnetite-mines.pdf?rev=886a3cedafb34e39887bc36de3893403&sc_lang=en

4 Credible options that have been assessed

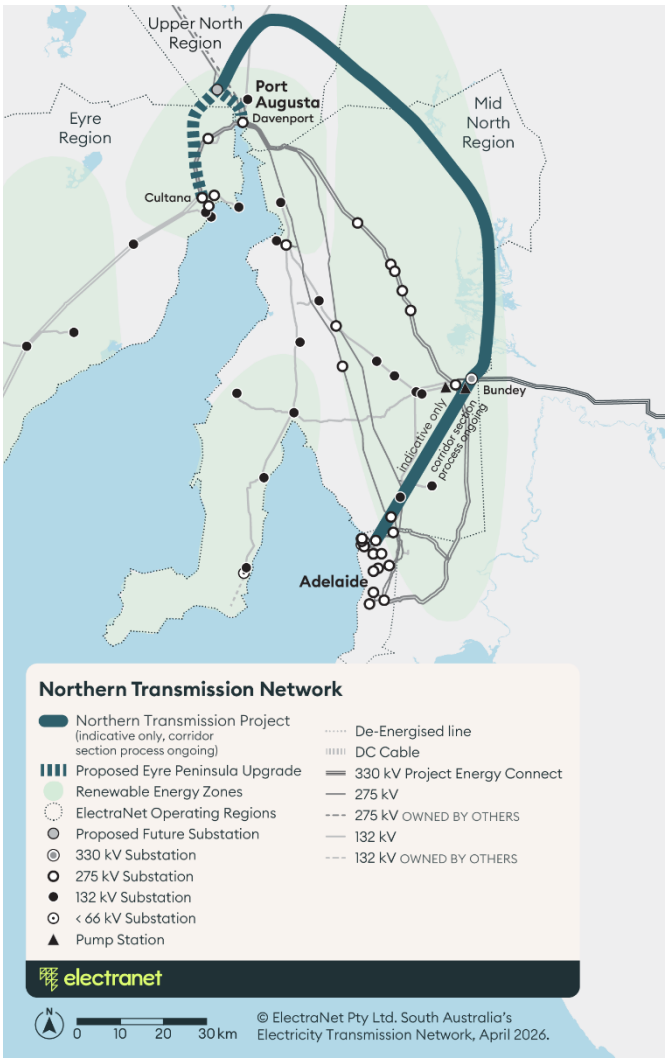
There are two distinct transmission paths of interest for the credible options considered in this PADR, both of which originate from Bundey substation near Robertstown.

Specifically, there is the:

- Mid North to Metro Adelaide section (southern section); and
- Mid North to Narcoona section (northern section).

These sections serve complementary purposes in addressing South Australia's electricity network needs and their indicative paths are shown in Figure 7 below.

Figure 7: Two key sections for the credible options



The southern section was the focus of the ISP candidate option and spans approximately 130-140 kilometres from Bundey substation to northern Adelaide. This section is critical for delivering electricity from northern renewable generation zones to Adelaide's growing demand centre.

The northern section extends approximately 350-400 km from Bundey substation to Narcoona[63] in the northeastern Eyre Peninsula. The northern section will unlock renewable energy connections in the Mid North, Northern, and Eastern Eyre Peninsula REZs while creating a high-capacity path to support emerging industrial load centres.

ElectraNet notes that, while the draft 2026 ISP candidate option focuses on development of the southern section, future renewables development and interest from LILs suggests that the northern section also has the potential to deliver net market benefits and meets the requirements of the identified need.

We have developed and assessed nine RIT-T options for assessment in this PADR by evaluating a number of 'solutions' for each section. Each solution reflects different trade-offs between costs, transfer capacity, system resilience, expandability, and technical complexity.

The various solutions considered are discussed in the following two sections (and in section 4.4 for solutions considered but not progressed). How these solutions have been considered as 'credible options' for the RIT-T assessment is then presented in section 4.3.

ElectraNet would be the proponent for any network works identified as part of the preferred option for this RIT-T.

As outlined in section 6.1, and as facilitated by the extension to the PADR publication date, additional planning undertaken by ElectraNet has led to refined cost estimates compared to the estimates included in the 2025 AEMO Electricity Network Options Report (and adopted in the draft 2026 ISP). ElectraNet has provided the latest cost estimates to AEMO and expects these costs to be taken in account in the assessment for the 2026 ISP. The costs correspond to 'Class 4' estimates, which represent an expected accuracy of +50%/-30%, with exception of option S4 which corresponds to a 'Class 5' estimate, +100%/-50%.

From early 2025, ElectraNet has undertaken early engagement with communities, businesses and industry to help us understand changing energy needs, priorities and concerns. The scope of the feedback from this engagement is outlined in section 4.5, including how it has resulted in one corridor emerging as preferred for all northern solutions.

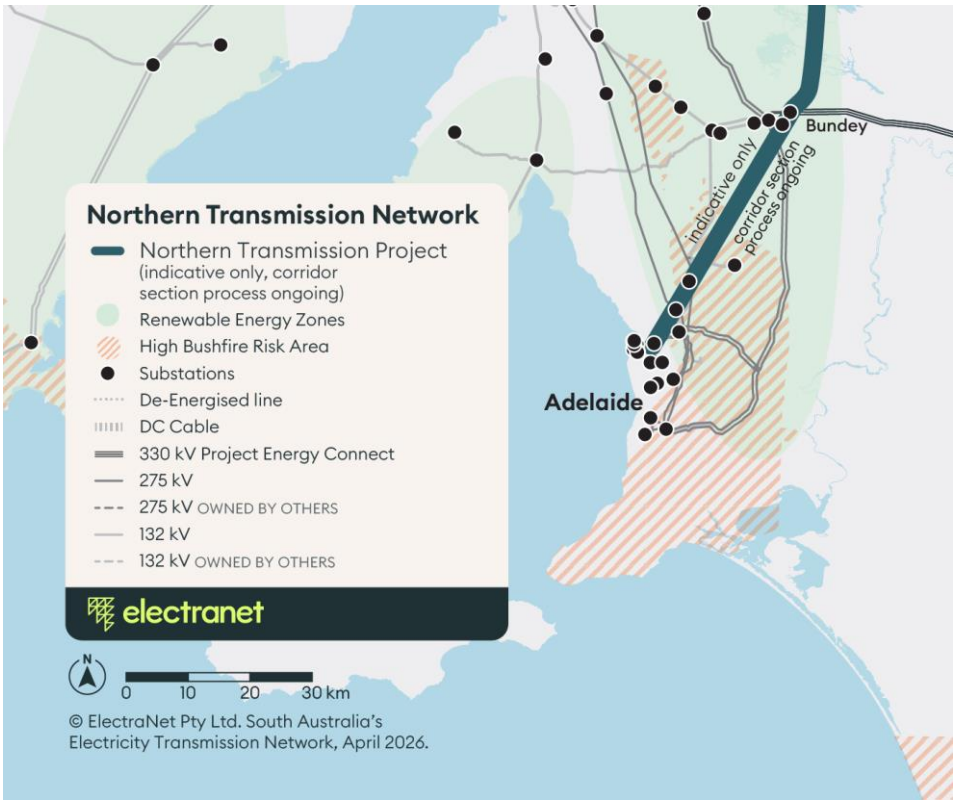
In May 2025, we released a 'route development fact sheet' that outlined the early planning stage route considerations for this project, as well as ElectraNet's route development process more generally. While the broad location (and capacity) of the transmission lines will be determined via this RIT-T, ElectraNet is working closely with all stakeholders, including local communities, landholders, Traditional Owners, businesses and industries to shape early planning for NTx and inputs into the RIT-T and subsequent detailed route development processes.[64]

[63] The scope revision to connect to Narcoona, as opposed to Cultana, is discussed in section 4.2. This name might change when a more precise location for this site is determined.
[64] ElectraNet, *Northern Transmission Project*, Project Fact Sheet, May 2025.

4.1 Four southern 'solutions' have been considered

The figure below shows the relevant part of our network that the solutions would be in, as well as an indicative path for these solutions.[65]

Figure 8: Indicative path for the southern solutions



ElectraNet is still in the corridor development phase for NTx South (described in section 4.5) with multiple corridor options still under consideration. When undertaking community engagement on a four corridor options for the northern part of the southern solution, community feedback called on ElectraNet to consider broadening the study area with the view that land outside of the initial study area would be more suitable for transmission and better meet project needs. In response to this ElectraNet is considering a new possible corridor option. We expect to report on this as part of the PACR (as well as via our ongoing stakeholder consultation). This is not expected to result in a new solution, but rather a potential high-level re-routing of a portion of the northern part of the southern solutions.

4.1.1 'S1' – Bundey to Para – 275 kV (ISP candidate option)

While we have included S1 in the analysis in this PADR, we no longer consider connecting to Para a likely option under the RIT-T on account of the additional future costs it involves for expanding the network, as well as its relatively high bushfire risk. Specifically:

[65] Please note that this figure shows an indicative path for the southern solution.

- ElectraNet engaged KPMG to undertake system risk studies regarding the bushfire risk around the Adelaide Hills, which found that having NTx connect to Para would involve a high bushfire risk compared to the other southern solutions.

  The Para substation is critical for the operation of the electrical network around Adelaide. A major bushfire event in the Adelaide Hills that affected operations at the Para substation could limit the capacity of the network to supply Adelaide and increase the risk of substantial unserved energy.

  This would be more critical if NTx connects to Para as the power transfer via the site will increase with the connection of two more circuits. Increasing the risks of a single point of failure.

  Connecting to a new site around Bolivar/Dry Creek (under S2-S4) will reduce the risk by not increasing the power transfer at Para and would instead create a new hub around Adelaide. The resilience benefits provided by going to the new site have been estimated by KPMG and included in the PADR assessment (as outlined in section 6.4).

- Our technical studies have shown that if we connect NTx to Para, the transfer capacity at Para would reach its maximum transfer capability and it would then not be possible to inject any additional power at the site.

  Under these conditions some of our future projects[66] to increase capacity on the existing 275 kV transmission lines to allow for additional power from the Mid North into Adelaide will not be able to proceed and would require a new site to be established to diversify the power around Metropolitan Adelaide.

  The cost of establishing a new site, if not undertaken now, will be more expensive and difficult from the perspective of obtaining community support and social licence (given the location in Metropolitan Adelaide).[67]

  In current terms, this is estimated to see land costs escalate from $212 million to approximately $450 million if we delay five years as land use further shifts from agriculture to an urban environment.

On balance, we consider the use of Para for NTx to be inferior to a new site around Bolivar/Dry Creek and, ultimately, not commercially feasible under the RIT-T for the above reasons, i.e., the need to quarantine the existing spare bays for future expansion, and the elevated bushfire risk that comes with connecting new lines to Para under NTx. We have however included S1 in the PADR as an option assessed given it is the draft 2026 ISP candidate option.

S1 is the draft 2026 (and 2024) ISP candidate option and involves the following scope of works:[68]

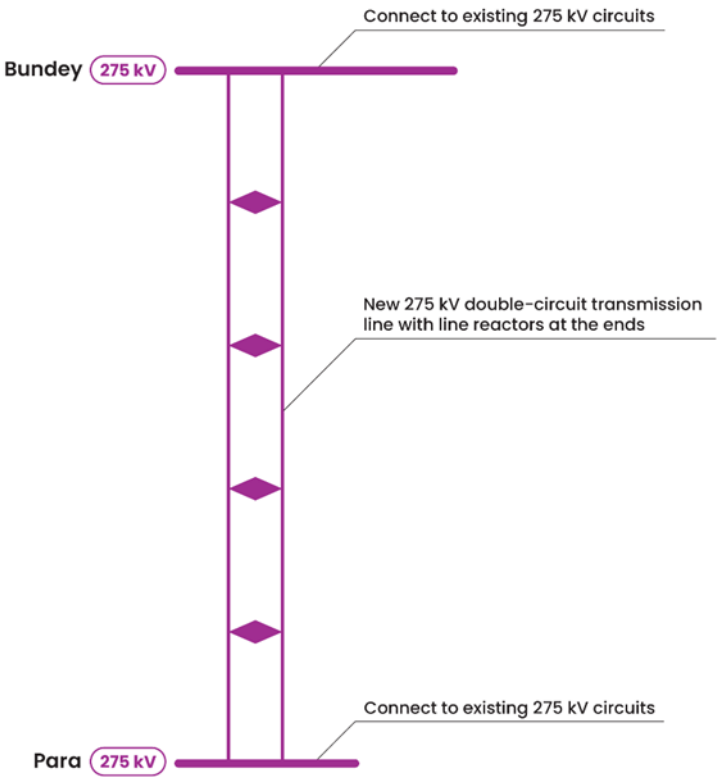
- Build a 275 kV double-circuit line between Bundey and Para (twin conductor Olive or similar).

[66] For example, the 'Mid North Reinforcement' project – see ElectraNet 2025 TAPR, pp. 85 & 131.
[67] While this new site may be the same one near Bolivar/Dry Creek that is included in Options S2-4, it would be expected to involve a significantly greater cost, in real terms, and community impact for this future work than under Options S2-S4. This is due to it being needed further into the future and the fact that this area is rapidly being turned into residential properties (meaning that the cost and community impact are expected to increase substantially further into the future).
[68] Unless otherwise stated, any additional specification provided here, or for any of the other solutions, compared to the draft 2026 ISP options, is due to a further refining of that solution since that point in time.

- 2 x new line-connected reactors at Bundey
- 2 x new line-connected reactors at Para
- Tie-in 275 kV transmission lines at Para
- Full disconnection of the existing 132 kV lines Waterloo-Templers and Roseworthy-Para
- Two new 132 kV single-circuit lines from Templers West to Templers and from Roseworthy to Templers West.
- Additional 160 MVA, 275/132 kV transformer at Templers West and
- Replacement of 275/132 kV transformer at Robertstown with a 250 MVA unit

The figure below provides an overview of this solution, noting the lines represent network connections schematically, not a specific line route.

Figure 9: Network diagram for S1



The nominal rating of the new transmission line would be around 2,000 MW and it would allow for an approximated additional 600 MW of transfer capacity from the Mid North REZ to Adelaide. While the augmentation increases power flows into Para, network analysis has shown connecting NTx to Para would result in congestion on several of the existing transmission lines exiting the site as power is transmitted to the rest of the metropolitan region. To resolve this issue two existing 275 kV transmission lines that cross over Para would be tie-in to the site. These lines are the TIPS-Cherry Gardens and the TIPS - Magill. Nonetheless, further congestion is evident on this option and augmentation provides a reduced output compared to alternative options.

The estimated capital cost of this solution is $902.3 million, as shown in the table below.

In addition to these 'solution-specific' costs, ElectraNet has also incurred (and forecasts to incur) certain 'early works' costs (as outlined in section 6.1).[69] The incurred early works costs are not included in the estimate above or table below, nor for those corresponding sections for the other options. The incurred costs have also not been included in the NPV assessment.

Table 1: Estimated capital cost breakdown for S1[70]

Type	Description	Number	Capital cost ($ million)
Bundey 275 kV			
Switchyard augmentation	Switchyard extension with two additional 3CBs diameters, populate one diameter with 2 CBs and next one with 1 CB. Additional control building. Includes two 50 MVAr line reactors.	-	55.6
Transmission line diversion	Divert and allow for crossing of transmission lines connected to other bays.	-	12.7
Sub-total			**68.3**
275 kV transmission line Bundey to Para			
275 kV transmission line	Double circuit 275 kV transmission line using twin conductor Olive or similar	120 km	414.6
Land	Land/easements	-	211.7
Environmental	Line environmental offsets		12.7
Sub-total			**638.9**
Para 275 kV			
Switchyard augmentation	Switchyard extension with two 3CBs diameters each with 2 CBs. Demolish building. Additional control building. Includes two 50 MVar reactors.	-	60.5
Transmission line diversion	Tie existing 275 kV transmission lines to Para. Rearrange several exits and corresponding transmission lines. Divert and allow for crossing of transmission lines connected to other bays.		17.6
Sub-total			**78.0**
132 kV augmentation			
Increase capacity at Templers West	Additional 160 MVA 230/132 kV transformer and 132 kV switchgear	-	57.5
Connect Templers to Templers West	Establish a single circuit 132 kV connection between Templers and Templers West and disconnect the 132 kV lines Waterloo-Templers and Roseworthy-Para	-	2.0

[69] The early works activities include the costs for stakeholder engagement, land use planning and acquisition, project development and procurement activities.
[70] Unless otherwise stated, all costs (and benefits) presented in this PADR are in 2025/26 dollars.

Type	Description	Number	Capital cost ($ million)
Connect Roseworthy to Templers West	New 132 kV single circuit transmission line connecting Roseworthy to Templers West	10 km	41.0
Transformer replacement	Replace existing 132/275 kV transformer at Robertstown with a 250 MVA	1	16.6
Sub-total			**117.1**
Total			**902.3**

All works are expected to take two years, commencing commissioning in 2029/30.

4.1.2 'S2' – Bundey to new site around Bolivar/Dry Creek[71] – 275 kV

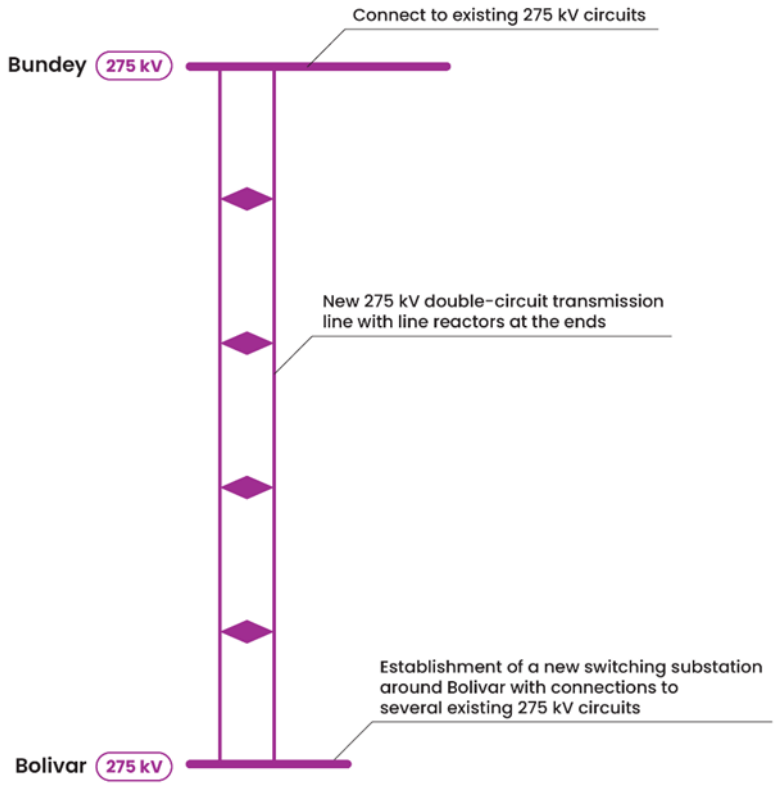
S2 was included in the 2025 AEMO Electricity Network Options Report, following further planning studies by ElectraNet after the 2024 ISP.[72] It involves the following scope of works:

- Build a 275 kV double-circuit line from Bundey to a location close to Bolivar/Dry Creek (twin conductor Olive or similar)
- 2 x new 275 kV line-connected reactors at Bundey
- New 275 kV substation at a location close to Bolivar/Dry Creek
- 2 x new 275 kV line-connected reactors at Bolivar/Dry Creek
- Connect new substation to existing metropolitan 275 kV network.
- Full disconnection of the existing 132 kV lines Waterloo-Templers and Roseworthy-Para
- Two new 132 kV single-circuit lines from Templers West to Templers and from Roseworthy to Templers West.
- Additional 160 MVA, 275/132 kV transformer at Templers West and
- Replacement of 275/132 kV transformer at Robertstown with a 250 MVA unit

The figure below provides an overview of this solution, noting the lines represent network connections schematically, not a specific line route.

[71] The final name for the site would be finalized once its final location is determined.
[72] This option does not feature in the draft 2026 ISP as it only lists one credible option – Option S1.

Figure 10: Network diagram for S2



The nominal rating of the new transmission line would be around 2,000 MW and it would allow for an additional 1,600 MW of transfer capacity from the Mid North REZ to Adelaide.

The estimated capital cost of this solution is $1,406.4 million as shown in the table below.

Table 2: Estimated capital cost breakdown for S2

Type	Description	Number	Capital cost ($ million)
Bundey 275 kV			
Switchyard augmentation	Switchyard extension with two additional 3CBs diameters, populate one diameter with 2 CBs and next one with 1 CB. Additional control building. Includes two 50 MVAr line reactors.	-	56.1
Transmission line diversion	Divert and allow for crossing of transmission lines connected to other bays.	-	12.8
Sub-total			**68.9**
275 kV transmission line Bundey to Bolivar/Dry Creek			
275 kV transmission line	Double circuit 275 kV transmission line using twin conductor Olive or similar	134 km	494.0
Land	Land/easements	-	431.0
Environmental	Line environmental offsets		12.9
Sub-total			**937.9**

Type	Description	Number	Capital cost ($ million)
New Bolivar/Dry Creek 275 kV site			
Land	Land acquisition	-	39.4
Establish new Bolivar/Dry Creek site	Preparatory civil works to upgrade the site. Establish a 275 kV switchyard with ten 2CBs diameters each with 2 CBs and control buildings. Includes two 50 MVar reactors.	-	209.6
Transmission line diversion	Divert and tie existing 275 kV transmission lines to Bolivar/Dry Creek. Allow for crossing of transmission lines in the area.		32.5
Sub-total			**281.5**
132 kV reconfiguration			
Increase capacity at Templers West	Additional 160 MVA 230/132 kV transformer and 132 kV switchgear	-	58.2
Connect Templers to Templers West	Establish a single circuit 132 kV connection between Templers and Templers West and disconnect the 132 kV lines Waterloo-Templers and Roseworthy-Para	-	2.0
Connect Roseworthy to Templers West	New 132 kV single circuit transmission line connecting Roseworthy to Templers West	10 km	41.3
Transformer replacement	Replace existing 132/275 kV transformer at Robertstown with a 250 MVA	1	16.7
Sub-total			**118.1**
Total			**1,406.4**

All works are expected to take two years, commencing commissioning in 2029/30.

4.1.3 'S3' – Bundey to new site around Bolivar/Dry Creek[73] – 330 kV

S3 was included in the 2025 AEMO Electricity Network Options Report (and was also included as Option 2 in the 2024 ISP).[74] It involves the following scope of works:

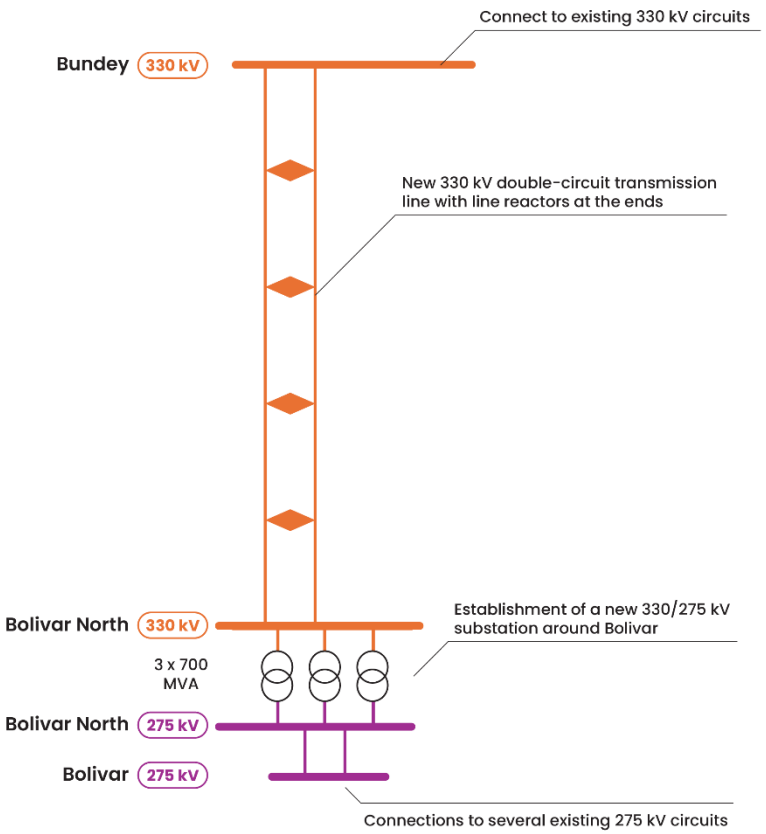
- Build a 330 kV double-circuit line from Bundey to Bolivar/Dry Creek (triple conductor Mango or similar)
- 2 x new 330 kV line-connected reactors at Bundey
- New 330/275 kV transformation substation at a location close to Bolivar – Bolivar North. The site includes three 700 MVA 330/275 kV transformers, with connections at 330 kV to the new transmission line to Bundey and at 275 kV to the new Bolivar site

[73] The final name for the site would be finalized once its final location is determined.
[74] This option does not feature in the draft 2026 ISP as it only lists one credible option – Option S1.

- Build a short connection (expected less than 10 km) with multiple 275 kV circuits connecting Bolivar to Bolivar North, with twin Olive or similar
- New 275 kV substation at location close to Bolivar/Dry Creek
- 2 x new 330 kV line-connected reactors at Bolivar/Dry Creek
- Connect new substation to existing metropolitan 275 kV network
- Full disconnection of the existing 132 kV lines Waterloo-Templers and Roseworthy-Para
- Two new 132 kV single-circuit lines from Templers West to Templers and from Roseworthy to Templers West
- Additional 160 MVA, 275/132 kV transformer at Templers West and
- Replacement of 275/132 kV transformer at Robertstown with a 250 MVA unit

The figure below provides an overview of this solution, noting the lines represent network connections schematically, not a specific line route.

Figure 11: Network diagram for S3



The nominal rating of the new transmission line would be around 2,800 MW and it would allow for an additional 2,000 MW of transfer capacity from the Mid North REZ to Adelaide.

The estimated capital cost of this solution is $1,746.3 million, as shown in the table below.

Table 3: Estimated capital cost breakdown for S3

Type	Description	Number	Capital cost ($ million)
Bundey 330 kV			
Switchyard augmentation	Switchyard extension with two 3CBs diameters each with 3CBs Additional control building. Includes two 50 MVar line reactors.	-	37.5
Sub-total			**37.5**
330 kV transmission line Bundey to Bolivar North			
330 kV transmission line	Double circuit 330 kV transmission line using triple conductor Mango or similar	134 km	550.8
Land	Land/easements	-	432.4
Environmental	Line environmental offsets		12.8
Sub-total			**996.1**
New Bolivar North 330/275 kV transformation site			
Land	Land acquisition	-	39.5
Establish a new 330/275 kV transformation site	Preparatory civil works to upgrade the site. Establish a 330 kV switchyard with five 2CBs diameters each with 2 CBs. Includes two 50 MVar 330 kV reactors and three 3ph – 700 MVA 330/275 kV transformers. Establish a 275 kV switchyard with three 3CBs diameters each with 3 CBs. Connection to Bolivar/Dry Creek 275 kV.		272.5
Sub-total			**311.9**
New Bolivar/Dry Creek 275 kV site			
Land	Land acquisition	-	39.5
Establish new Bolivar/Dry Creek site	Preparatory civil works to upgrade the site. Establish a 275 kV switchyard with ten 2CBs diameters each with 2 CBs and control buildings.	-	210.3
Transmission line diversion	Divert and tie existing 275 kV transmission lines to Bolivar/Dry Creek. Allow for crossing of transmission lines in the area.		32.6
Sub-total			**282.3**
132 kV reconfiguration			
Increase capacity at Templers West	Additional 160 MVA 230/132 kV transformer and 132 kV switchgear	-	58.2
Connect Templers to Templers West	Establish a single circuit 132 kV connection between Templers and Templers West and disconnect the 132 kV lines Waterloo-Templers and Roseworthy-Para	-	2.0
Connect Roseworthy to Templers West	New 132 kV single circuit transmission line connecting Roseworthy to Templers West	10 km	41.5

Type	Description	Number	Capital cost ($ million)
Transformer replacement	Replace existing 132/275 kV transformer at Robertstown with a 250 MVA	1	16.8
Sub-total			**118.5**
Total			**1,746.3**

All works are expected to take two years, commencing commissioning in 2029/30.

4.1.4 'S4' – Bundey to new site around Bolivar/Dry Creek[75] – 500 kV

S4 was included in the 2025 AEMO Electricity Network Options Report, following additional planning studies undertaken by ElectraNet after the 2024 ISP.[76] This high-capacity southern variant has been included in light of the now higher expected data centre load close to Adelaide.

S4 involves the following scope of works:

- New 500/275 kV transformation substation at a location close to Bundey – Bundey North. The site includes three 1,500 MVA 500/275 kV transformers, with connections at 500 kV to the new transmission line to Bolivar North and at 275 kV to Bundey
- 2 x 500 kV line-connected reactors at new Bundey North
- Build a short connection (~ less than 10 km) with multiple 275 kV circuits connecting Bundey to Bundey North, with twin Olive or similar
- Build a 500 kV double-circuit line from a site close to Bundey (Bundey North) to a site around Bolivar/Dry Creek (Bolivar North), with quad Olive or similar.
- New 500/275 kV transformation substation at a location close to Bolivar – Bolivar North. The site includes three 1,500 MVA 500/275 kV transformers, with connections at 500 kV to the new transmission line to Bundey North and at 275 kV to Bolivar
- 2 x new 500 kV line-connected reactors at new site Bolivar North
- Build a short connection (~ less than 10 km) with multiple 275 kV circuits connecting Bolivar to Bolivar North, with twin Olive or similar
- Connect Bolivar/Dry Creek to existing metropolitan 275 kV network.
- Full disconnection of the existing 132 kV lines Waterloo-Templers and Roseworthy-Para
- Two new 132 kV single-circuit lines from Templers West to Templers and from Roseworthy to Templers West.
- Additional 160 MVA, 275/132 kV transformer at Templers West and
- Replacement of 275/132 kV transformer at Robertstown with a 250 MVA unit

[75] The final name for the site would be finalized once its final location is determined.
[76] This option does not feature in the draft 2026 ISP as it only lists one credible option – Option S1.

The figure below provides an overview of this solution, noting the lines represent network connections schematically, not a specific line route.

The nominal rating of the new transmission line would be around 7,000 MW and it would allow for an additional 4,100 MW of transfer capacity from the Mid North REZ to Adelaide.

The estimated capital cost of this solution is $3,515.8 million, as shown in the table below.

While all other option cost estimates are Class 4 estimates, this option's estimate is Class 5 at this stage.

Figure 12: Network diagram for S4

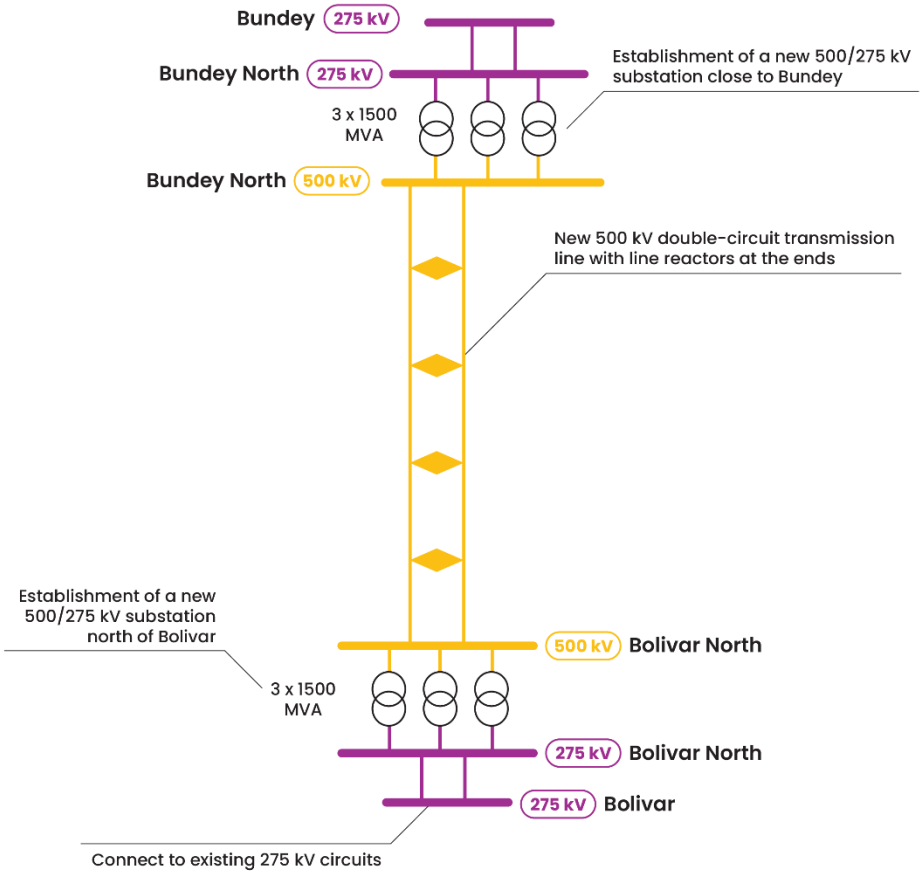


Table 4: Estimated capital cost breakdown for S4

Type	Description	Number	Capital cost ($ million)
Bundey 275 kV			
Switchyard augmentation	Extension of bench and switchyard extension with three additional 3CBs diameters, populate two diameters with 3 CBs and next one with 1 CB. Additional control building.	-	131.6
Transmission line diversion	Divert and allow for crossing of transmission lines connected to other bays.	-	12.9
Sub-total			**144.6**

Type	Description	Number	Capital cost ($ million)
New Bundey North 500/275 kV transformation site			
Land	Acquire land for new site	-	14.9
New 500/275 kV site	Establish a new 275 kV switchyard with three 3CBs diameters each with 3 CBs and three 3ph – 1500 MVA 500/275 kV transformers and control buildings. Establish a new 500 kV switchyard with five 2CBs diameters each with 2 CBs. Includes two 500 kV 50 MVar reactors.	-	388.5
Sites connection	275 kV transmission line connecting Bundey to Bundey North	10 km	103.3
Sub-total			**506.7**
500 kV transmission line Bundey North to Bolivar North			
500 kV transmission line	Double circuit 500 kV transmission line using quad conductor Olive or similar	134 km	725.3
Land	Land/easements	-	529.6
Environmental	Line environmental offsets		12.9
Sub-total			**1,267.8**
New Bolivar North 500/275 kV transformation site			
Land	Land acquisition	-	72.5
Establish a new 500/275 kV transformation site	Preparatory civil works to upgrade the site. Establish a 500 kV switchyard with five 2CBs diameters each with 2 CBs. Includes two 50 MVar 500 kV reactors and three 3ph – 1500 MVA 500/275 kV transformers. Establish a 275 kV switchyard with three 3CBs diameters each with 3 CBs.		457.0
Sites connection	275 kV transmission line/cable connecting Bolivar to Bolivar North	10 km	659.7
Sub-total			**1,189.3**
New Bolivar/Dry Creek 275 kV site			
Land	Land acquisition	-	39.7
Establish new Bolivar/Dry Creek site	Preparatory civil works to upgrade the site. Establish a 275 kV switchyard with six 3 CBs diameters each with 3 CBs. Control building.	-	215.6
Transmission line diversion	Divert and tie existing 275 kV transmission lines to Bolivar/Dry Creek. Allow for crossing of transmission lines in the area.		32.8
Sub-total			**288.1**
132 kV reconfiguration			
Increase capacity at Templers West	Additional 160 MVA 230/132 kV transformer and 132 kV switchgear	-	58.6

Type	Description	Number	Capital cost ($ million)
Connect Templers to Templers West	Establish a single circuit 132 kV connection between Templers and Templers West and disconnect the 132 kV lines Waterloo-Templers and Roseworthy-Para	-	2.0
Connect Roseworthy to Templers West	New 132 kV single circuit transmission line connecting Roseworthy to Templers West	10 km	41.7
Transformer replacement	Replace existing 132/275 kV transformer at Robertstown with a 250 MVA	1	16.9
Sub-total			**119.2**
Total			**3,515.8**

All works are expected to take two years, commencing commissioning in 2029/30.

4.2 Four northern 'solutions' have been considered

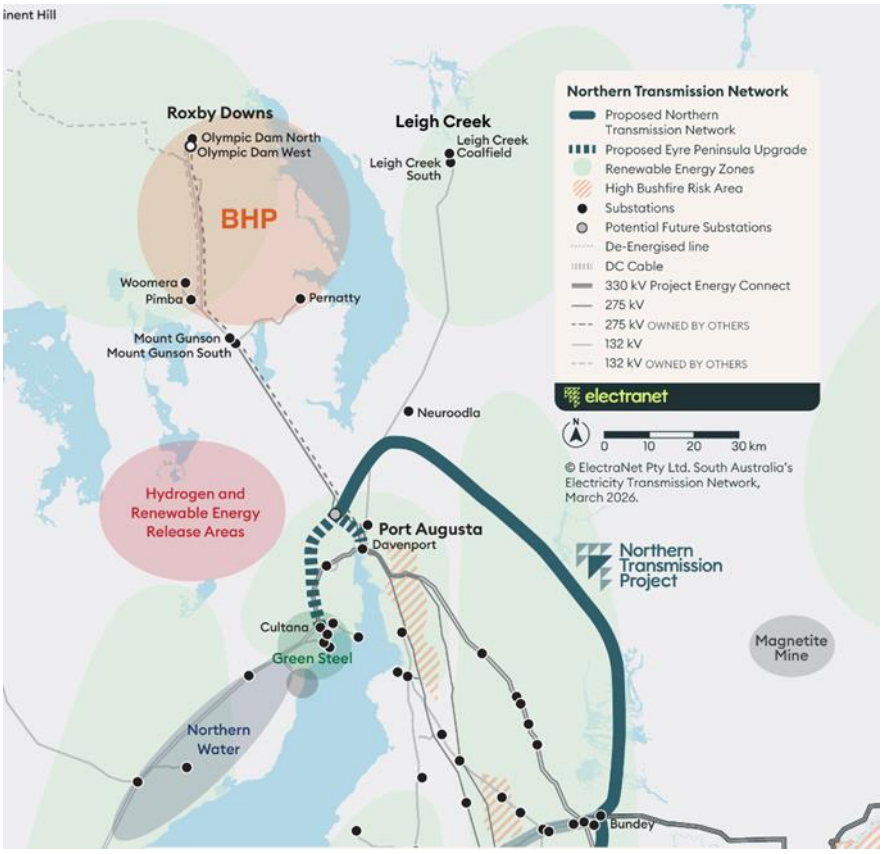
All northern solutions follow the same high-level corridor and have been tested through the additional community consultation undertaken since early 2025 (i.e., that outlined in section 4.5 below).[77]

Multi Criteria Analysis (MCA) workshops were undertaken to evaluate alternative corridor choices based on specific criteria, which were agreed with participants prior to assessment, and which confirmed the advantages of utilising this corridor (i.e., low cost of land, use of land primarily used for grazing instead of high productivity cropping, low number of residences along the proposed corridor, considers and mitigates potential impacts on areas of significant cultural heritage, and utilises a favourable route through the Flinders ranges).

The figure below shows the part of our network the northern solutions would be built in, as well as a high-level indicative route for the new lines. It also shows indicative locations for major LILs expected in this part of our network.

[77] The one exception to this is the recent update to the location of the northern connection point in light of the Eyre Peninsula Upgrade RIT-T PACR. As outlined below, this has led to the northern end now connecting to Narcoona, as opposed to Cultana

Figure 13: Indicative route for the northern solutions



All northern solutions involve incremental upgrade and minor re-routing costs for the preferred option in the recently finalised Eyre Peninsula Upgrade RIT-T. Specifically, the new Davenport to Cultana East 275 kV circuit being built as part of the preferred option for that RIT-T could be upgraded if required and would connect into the northern solutions assessed in this PADR. The connection would take place at the future Narcoona[78] site to be established by the Eyre Peninsula Upgrade preferred option.[79]

The interaction with the preferred option for the Eyre Peninsula has resulted in a minor scope revision (shortening) for the northern variants considered in this RIT-T compared to at the time of preparing the 2025 AEMO Electricity Network Options Report. This is due to them now going via Narcoona, which is approximately 70 km north of Cultana.

4.2.1 'N1' – Bundey to Narcoona[78] – 275 kV

N1 was included in the 2025 AEMO Electricity Network Options Report (and was also included as Option 3 in the 2024 ISP).[80]

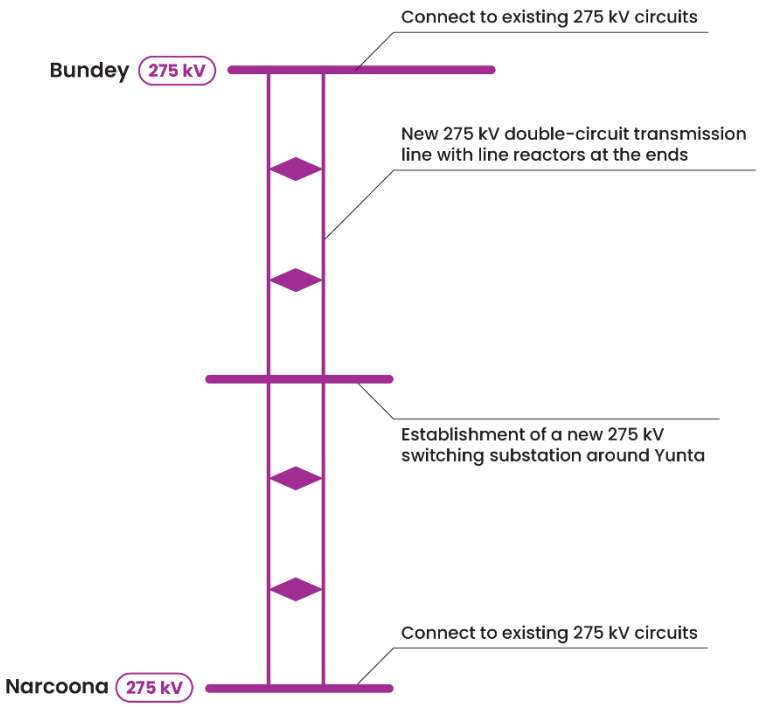
N1 involves the following scope of works:

[78] The site name of Narcoona might change when a more precise location for this site is determined
[79] The interaction with the separate Eyre Peninsula upgrade is outlined at the end of this section.
[80] This option does not feature in the draft 2026 ISP as it only lists one credible option – Option S1.

- A new 275 kV double-circuit line from Bundey to Yunta to Narcoona (triple conductor Mango or similar)
- A new 275 kV substation in locality of Yunta[81]
- 4 x new 275 kV 50 MVAr line-connected reactors at each end of Bundey - Yunta 275 kV lines.
- 4 x new 275 kV 50 MVAr line-connected reactors at each end of Yunta - Narcoona 275 kV lines.
- Two +/-100 MVAr SVCs at Yunta and two +/-100 MVAr SVCs at Narcoona

The figure below provides an overview of this solution, noting the lines represent network connections schematically, not a specific line route.

Figure 14: Network diagram for N1



The nominal rating of the new transmission line would be around 2,400 MW and it would allow for an additional 1,200 MW of transfer capacity in aggregate from the Mid North REZ, and Northern and Eastern Eyre Peninsula REZs.

The estimated capital cost of this solution is $1,726.8 million, as shown in the table below.

[81] Further network studies will confirm if the proposed Yunta substation is needed, to be reported in the PACR.

Table 5: Estimated capital cost breakdown for N1

Type	Description	Number	Capital cost ($ million)
Bundey 275 kV			
Switchyard augmentation	Extension of the bench and switchyard for two new 3CB diameters, populate one diameter with 2 CBs and one diameter with 1 CB. Additional control building. Includes two 50 MVar line reactors.	-	114.0
Sub-total			**114.0**
275 kV transmission line Bundey to Narcoona via Yunta			
275 kV transmission line	Double circuit 275 kV transmission line using triple conductor Mango or similar	370 km	1,122.2
Land	Land/easements	-	16.8
Environmental	Line environmental offsets		55.3
Sub-total			**1,194.3**
New Yunta 275 kV			
Land	Acquire land for new site		1.0
Establish new site at Yunta	Establish a new 275 kV site with two new 3CB diameters each with 3 CBs and two 2CB diameters each with 2 CBs. Additional control building. Includes four 50 MVar line reactors and two +/- 100 MVar SVCs.	-	218.1
Sub-total			**219.1**
Narcoona 275 kV			
Switchyard augmentation	Extension of the switchyard with two new 3CB diameters each with 3 CBs and two 2CB diameters each with 2 CBs. Additional control building. Includes two 50 MVar line reactors and two +/- 100 MVar SVCs	-	189.5
Sub-total			**189.5**
132 kV reconfiguration			
Automated protection system	Remedial Action Scheme (RAS)	1	9.9
Sub-total			**9.9**
Total			**1,726.8**

All works are expected to take three years, commencing commissioning in 2031/32.

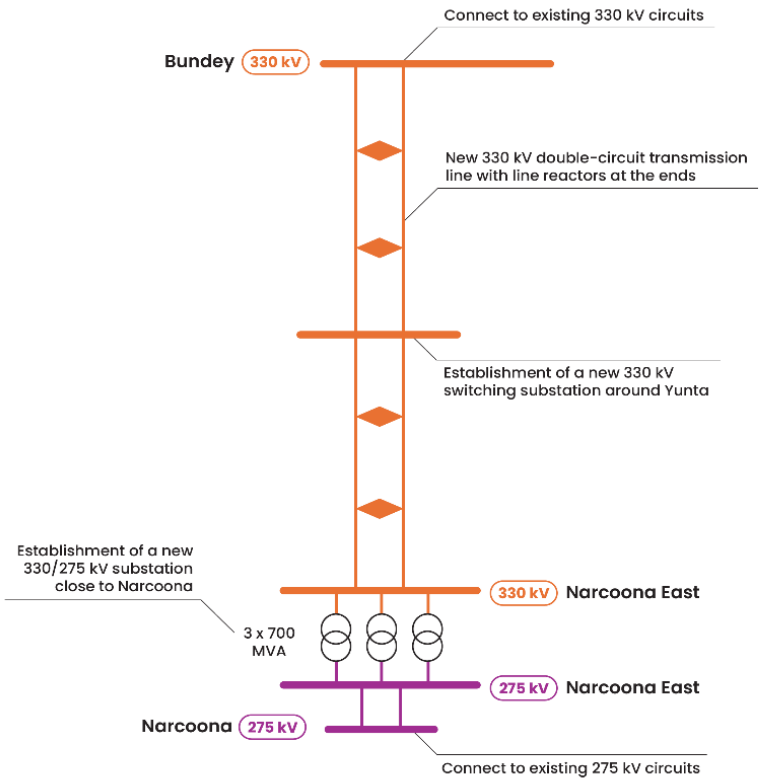
4.2.2 'N2' – Bundey to Narcoona[82] – 330 kV

N2 was included in the 2025 AEMO Electricity Network Options Report (and was also included as Option 4 in the 2024 ISP).[83] It involves the following scope of works:

- A new 330 kV double-circuit line from Bundey to Yunta to Narcoona (triple conductor Mango or similar).
- A new 330 kV substation in locality of Yunta[84]
- A new 330 kV substation at Narcoona (Narcoona East) with three 700 MVA 330/275 kV transformers
- A new 275 kV connection between the new substation Narcoona East and Narcoona
- 4 x new 330 kV 50 MVAr line-connected reactors at each end of Bundey - Yunta 330 kV lines.
- 4 x new 330 kV 50 MVAr line-connected reactors at each end of Yunta - Narcoona East 330 kV lines.
- Two +/-100 MVAr SVCs at Yunta and two +/-100 MVAr SVCs at Narcoona East

The figure below provides an overview of this solution, noting the lines represent network connections schematically, not a specific line route.

Figure 15: Network diagram for N2



[82] The site name of Narcoona might change when a more precise location for this site is determined
[83] This option does not feature in the draft 2026 ISP as it only lists one credible option – Option S1.
[84] Further network studies will confirm if the proposed Yunta substation is needed, to be reported in the PACR.

The nominal rating of the new transmission line would be around 2,800 MW and it would allow for an additional 1,400 MW of transfer capacity in aggregate from the Mid North REZ, and Northern and Eastern Eyre Peninsula REZs.

The estimated capital cost of this solution is $2,045.3 million, as shown in the table below.

Table 6: Estimated capital cost breakdown for N2

Type	Description	Number	Capital cost ($ million)
Bundey 330 kV			
Switchyard augmentation	Extension of the switchyard for two new 3CB diameters with 2 CBs each. Additional control building. Includes two 50 MVar reactors	-	81.1
Sub-total			**81.1**
330 kV transmission line Bundey to Narcoona East via Yunta			
330 kV transmission line	Double circuit 330 kV transmission line using triple conductor Mango or similar	370 km	1,209.6
Land	Land/easements	-	16.8
Environmental	Line environmental offsets		55.4
Sub-total			**1,281.8**
New Yunta 330 kV			
Land	Acquire land for new site		2.0
Establish new site at Yunta	Establish a new 330 kV site with two new 3CB diameters each with 3 CBs and two 2CB diameters each with 2 CBs. Additional control building. Includes two 50 MVar line reactors and two +/- 100 MVar SVCs.	-	257.1
Sub-total			**259.1**
New Narcoona East 330/275 kV transformation site			
Land	Acquire land for new site		13.8
Establish a new 330/275 kV transformation site	Establish a 330 kV switchyard with seven 2CB diameters each with 2 CBs and three 3ph – 700 MVA 330/275 kV transformers. A 275 kV switchyard with three 3CB diameters each with 3 CBs. Includes two 50 MVar 330 kV reactors and two +/- 100 MVar SVCs. Control buildings.	-	346.2
Sub-total			**360.0**
Narcoona 275 kV			
Expand 275 kV switchyard	Extension of the switchyard with two new 3CB diameters with 2 CBs each. Additional control building.		53.4
Sub-total			**53.4**

Type	Description	Number	Capital cost ($ million)
Additional works			
Automated protection system	Remedial Action Scheme (RAS)	1	9.9
Sub-total			**9.9**
Total			**2,045.3**

All works are expected to take three years, commencing commissioning in 2031/32.

4.2.3 'N3' – Bundey to Narcoona[85] – 500 kV

N3 included in the 2025 AEMO Electricity Network Options Report following further planning studies undertaken by ElectraNet after the 2024 ISP.[86] It involves the following scope of works:

- A new 275/500 kV substation in the vicinity of Bundey (Bundey North) with three x 1500 MVA 500/330 kV transformers
- A new 275 kV connection between Bundey and the new site Bundey North
- A new 500 kV double-circuit line from Bundey North to Yunta to Narcoona East. (quad conductor Olive or similar)
- A new 500 kV substation in locality of Yunta[87]
- A new 500/275 kV substation at Narcoona East (in the vicinity of Narcoona) with three 1500 MVA 500/275 kV transformers
- A new 275 kV transmission line connecting Narcoona East to Narcoona
- 4 x new 500 kV 50 MVAr line-connected reactors at each end of Bundey North - Yunta 500 kV lines.
- 4 x new 500 kV 50 MVAr line-connected reactors at each end of Yunta - Narcoona East 500 kV lines.
- Two +/-100 MVAr dynamic reactive plants at Yunta and two +/-100 MVAr dynamic reactive plants at Narcoona East

We have included a 500 kV northern variant in order to test whether there are incremental net benefits under the high demand forecast. It has been developed since the 2024 ISP in light of the central and high demand forecasts increasing since then.

The figure below provides an overview of this solution, noting the lines represent network connections schematically, not a specific line route.

[85] The site name of Narcoona might change when a more precise location for this site is determined
[86] This option does not feature in the draft 2026 ISP as it only lists one credible option – Option S1.
[87] Further network studies will confirm if the proposed Yunta substation is needed, to be reported in the PACR.

The nominal rating of the new transmission line would be around 7,000 MW and it would allow for an additional 3,500 MW of transfer capacity from Bundey to Narcoona.

The estimated capital cost of this solution is $3,857.7 million, as shown in the table below.

Figure 16: Network diagram for N3

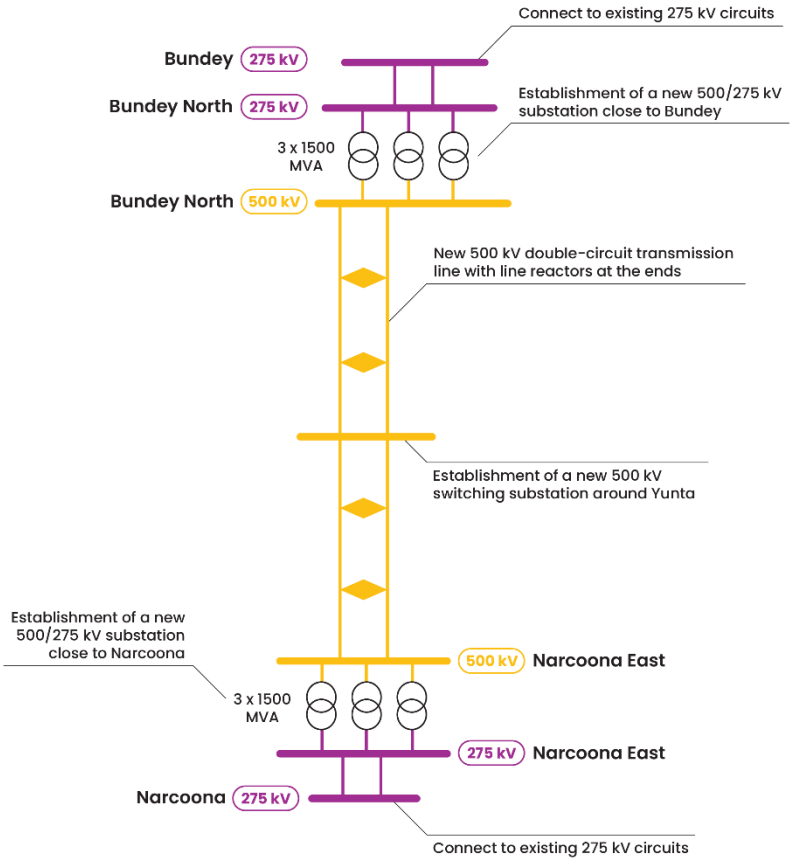


Table 7: Estimated capital cost breakdown for N3

Type	Description	Number	Capital cost ($ million)
Bundey 275 kV			
Switchyard augmentation	Extension of bench and switchyard extension with three additional 3CB diameters, populate two diameters with 3 CBs each and next one with 1 CB. Additional control building.	-	131.7
Sub-total			**131.7**
New Bundey North 500/275 kV transformation site			
Land	Acquire land for new site		14.9

Type	Description	Number	Capital cost ($ million)
New 500/275 kV site	Establish a new 275 kV switchyard with three new 3CB diameters each with 3 CBs and three 3ph – 1500 MVA 500/275 kV transformers and control buildings. Establish a new 500 kV switchyard with five 2CB diameters each with 2 CBs. Includes three 500 kV 50 MVar reactors.	-	388.7
Sites connection	275 kV transmission line connecting Bundey to Bundey North	10 km	103.4
Sub-total			**507.0**
500 kV transmission line Bundey North to Narcoona East via Yunta			
500 kV transmission line	Double circuit 500 kV double circuit transmission line using quad conductor Olive or similar	350 km	2,036.3
Land	Land/easements	-	16.9
Environmental	Line environmental offsets		55.7
Sub-total			**2,108.9**
New Yunta 500 kV			
Land	Acquire land for new site		2.0
Establish new site at Yunta	Establish a new 500 kV site with two 3CB diameters each with 3CBs and two 2CB diameters with 2 CBs each. Additional control building. Includes two 50 MVar line reactors and two +/- 100 MVar SVCs.	-	336.0
Sub-total			**338.0**
New Narcoona East 500/275 kV transformation site			
Land	Acquire land for new site		14.9
Establish a new 500/275 kV transformation site	Establish a 500 kV switchyard with seven 2CB diameters each with 2 CBs. Includes two 50 MVar 500 kV reactors and three 3ph – 1500 MVA 500/275 kV transformers. Establish a 275 kV switchyard with three 3CB diameters each with 3 CBs.		545.8
Sites connection	275 kV transmission line connecting Narcoona East to Narcoona	10 km	103.4
Sub-total			**664.1**
Narcoona 275 kV			
Expand 275 kV switchyard	Extension of the switchyard with two new 3CB diameters each with 3 CBs. Additional control building.		97.9
Sub-total			**97.9**
Additional works			
Automated protection system	Remedial Action Scheme (RAS)	1	10.0
Sub-total			**10.0**

Type	Description	Number	Capital cost ($ million)
Total			**3,857.7**

All works are expected to take three years, commencing commissioning in 2031/32.

4.2.4 'N4' – Bundey to Narcoona[88] – staged 500 kV

N4 was included in the 2025 AEMO Electricity Network Options Report following further planning studies by ElectraNet after the 2024 ISP.[89] N4 is a staged version of N3 and involves a new 500 kV line from Bundey to Narcoona, which is operated initially at 275 kV and later energised to 500 kV (if required).

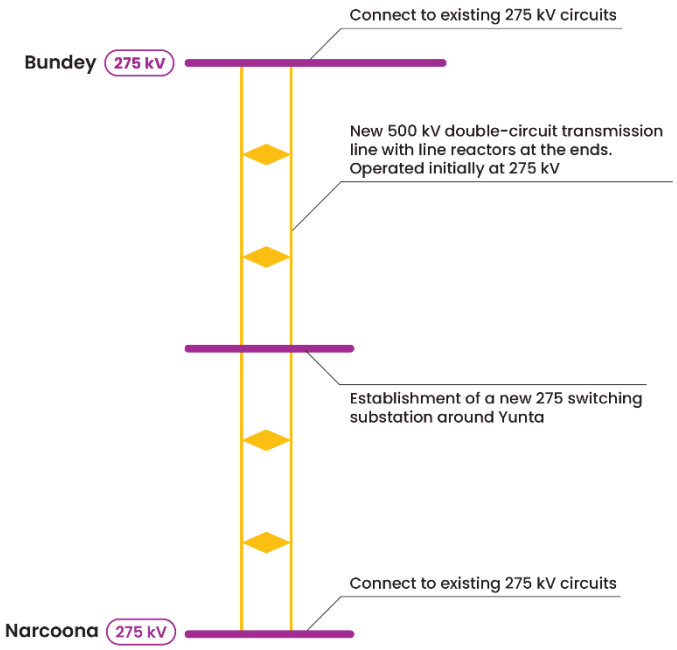
Specifically, N4 involves the following scope of works:

- Stage 1 (Line energised at 275 kV)
  - A new 500 kV designed double-circuit line from Bundey to Yunta to Narcoona (quad conductor Olive or similar)
  - A new 500 kV substation (operated initially at 275 kV) in the locality of Yunta[90]
  - 4 x new 250 kV 50 MVAr line-connected reactors at each end of Bundey - Yunta 500 kV lines.
  - 4 x new 250 kV 50 MVAr line-connected reactors at each end of Yunta - Narcoona 500 kV lines.
  - Two +/-100 MVAr dynamic reactive plants at Yunta and two +/-100 MVAr dynamic reactive plants at Narcoona
- Stage 2 (line upgrade – energised to 500 kV)
  - A new 275/500 kV substation in the vicinity of Bundey (Bundey North) with three 1500 MVA 500/275 kV transformers
  - A new 275 kV connection between Bundey and Bundey North
  - A new 500/275 kV substation at Narcoona North (in the vicinity of Narcoona) with three 1500 MVA 500/275 kV transformers
  - 4 x new 500 kV 50 MVAr line-connected reactors at each end of Bundey North - Yunta 500 kV lines.
  - 4 x new 500 kV 50 MVAr line-connected reactors at each end of Yunta - Narcoona North 500 kV lines.
  - Upgrade transformers for dynamic reactive plants at Yunta and Narcoona
  - Upgrade other switchgear as required at Yunta

[88] The site name of Narcoona might change when a more precise location for this site is determined
[89] This option does not feature in the draft 2026 ISP as it only lists one credible option – Option S1.
[90] Further network studies will confirm if the proposed Yunta substation is needed, to be reported in the PACR.

The figure below provides an overview of this solution, noting the lines represent network connections schematically, not a specific line route.

Figure 17: Network diagram for N4



Following Stage 1, the nominal rating of the transmission line would be close to 2,200 MW and the additional transfer capacity from the Mid North REZ and Northern and Eastern Eyre Peninsula REZs in aggregate would be close to 1,200 MW. With Stage 2 complete, the transfer capacities will be the as for N3 above.

The estimated capital cost of this solution is $2,857.6 million initially, as well as another $1,436.3 million when the line is upgrade to 500 kV, as shown in the table below.

Table 8: Estimated capital cost breakdown for N4 (Stage one)

Type	Description	Number	Capital cost ($ million)
Bundey 275 kV			
Switchyard augmentation	Extension of the bench and switchyard for two new 3CB diameters, populate one diameter with 2 CBs and one diameter with 1 CB. Additional control building. Includes two 50 MVar line reactors.	-	114.9
Land	Acquire land for future transformation site	-	14.9
Sub-total			**129.8**
500 kV transmission line Bundey to Narcoona via Yunta			
500 kV transmission line	Double circuit 500 kV transmission line using quad conductor Olive or similar (to operate initially at 275 kV)	350 km	2,036.3
275 kV connections	Double circuit 275 kV transmission line using triple conductor Mango or similar	20 km	103.5
Land	Land/easements	-	16.9

Type	Description	Number	Capital cost ($ million)
Environmental	Line environmental offsets		55.8
Sub-total			**2,212.4**
New Yunta 275 kV			
Land	Acquire land for new site		1.0
Establish new site at Yunta	Establish a new 275 kV site with two 3CB diameters with 3CBs each and two 2 CB diameters with two CBs each. Additional control building. Includes four 50 MVar line reactors and two +/- 100 MVar SVCs.	-	298.4
Sub-total			**299.4**
Narcoona 275 kV			
Switchyard augmentation	Extension of the switchyard with two new 3CB diameters each with 3 CBs and two 2CB diameters each with 2 CBs. Additional control building. Includes two 50 MVar line reactors and two +/- 100 MVar SVCs	-	191.0
Land	Acquire land for future transformation site	-	14.9
Sub-total			**205.9**
Additional works			
Automated protection system	Remedial Action Scheme (RAS)	1	10.0
Sub-total			**10.0**
Total			**2,857.6**

Table 9: Estimated capital cost breakdown for N4 (stage two)

Type	Description	Number	Capital cost ($ million)
Bundey 275 kV			
Switchyard augmentation	Extension of bench and switchyard extension with two additional 3CBs diameters each with 2 CBs. Additional control building. Remove 275 kV line reactors.	-	49.7
Sub-total			**49.7**
New Bundey North 500/275 kV transformation site			
New 500/275 kV site	Establish a new 275 kV switchyard with three 3CB diameters each with 3 CBs and three 3ph – 1500 MVA 500/275 kV transformers and control buildings. Establish a new 500 kV switchyard with five 2CB diameters each with 2 CBs. Includes two 500 kV 50 MVar line reactors.	-	388.9

Type	Description	Number	Capital cost ($ million)
Sites connection	Additional 275 kV transmission line connecting Bundey to Bundey North	10 km	51.7
Sub-total			**440.6**
Upgrade Yunta 275 kV to 500 kV			
Switchyard upgrade	Upgrade switchgear, reactors, SVCs and other devices	-	298.4
Sub-total			**298.4**
New Narcoona East 500/275 kV transformation site			
New 500/275 kV site	Establish a 500 kV switchyard with seven 2CB diameters each with 2 CBs. Includes two +/- 100 MVar SVCs or STATCOMs, three 3ph – 1500 MVA 500/275 kV transformers and two 50 MVar 500 kV reactors. Establish a 275 kV switchyard with three 3CB diameters each with 3 CBs.	-	546.1
Sites connection	Additional 275 kV transmission line connecting Narcoona to Narcoona North	10 km	51.7
Sub-total			**597.8**
Narcoona 275 kV			
Switchyard augmentation	Extension of bench and switchyard extension with two additional 3 CB diameters each with 2 CBs. Additional control building. Remove 275 kV line reactors.	-	49.7
Sub-total			**49.7**
Total			**1,436.3**

The initial works are expected to take three years, commencing commissioning in 2032/33. The 500 kV upgrade works are expected to take two years, commencing commissioning assumed in 2042/43.[91]

4.2.5 Interaction with the Eyre Peninsula upgrades

ElectraNet has been engaging with proponents of several potential significant load developments on the Eyre Peninsula. This has led us to conclude that expansion of the network capacity is now required and that, without action, parts of the transmission network will serve as constraints on the growth for both new and existing loads on the Eyre Peninsula.

We completed a RIT-T addressing this identified need in December 2025, which found the preferred option to be:[92]

[91] While a static approach has been taken for the assumed timing of Stage 2, this may be revisited in the PACR.
[92] https://electranet.com.au/projects/eyre-peninsula-upgrade/

- develop the Yadnarie North substation now to enable upgrading of the transmission lines between Yadnarie and Cultana to 275 kV operation; and
- establishing a new site close to Davenport and duplicating the Davenport to Cultana 275 kV circuits, subject to commitment of a further around 400 MW of electrical load by 1 January 2030 on the Eyre Peninsula network, supplied out of Davenport.

At this stage, we expect that the above investment will be progressed before works on NTx begin. We have therefore included these works in the base case for all scenarios for this PADR.

However, we note that, if the investment is not assumed to go ahead (and is not included in the base case for this RIT-T), it would affect the estimated costs and benefits of NTx. Specifically, the route and cost of the northern solutions would need to be rescoped and the wholesale market benefits of the entire NTx project would need to be re-estimated.

We intend to investigate further in the PACR the impact of there being insufficient load on the Eyre Peninsula to justify establishing a new site close to Davenport and duplicating the Davenport to Cultana 275 kV circuits (i.e., the second component(s) above).

4.3 Nine RIT-T options have been assessed

We have modelled the following nine credible options in this PADR assessment:

- each of the four southern solutions outlined above as standalone RIT-T options, consistent with the focus of the draft 2026 ISP candidate option (noting that we no longer consider the Para option (S1) to be a likely option);
- four 'end-to-end' options involving the combination of the southern solution that has the highest expected net market benefits and is considered credible (S2) with each northern solution; and
- the northern solution from the best performing of the 'end-to-end' options as a standalone option (N1).

Each of the RIT-T options modelled is summarised in the table below.

Table 10: Summary of the credible options assessed in this PADR

Option	Summary	Additional line capacity	Capital cost(s)
Standalone southern options[93]			
S1	Bundey to Para 275 kV (no longer considered a likely option)	2,000 MW	$902.3m
S2	Bolivar/Dry Creek route 275 kV	2,000 MW	$1,406.4m
S3	Bolivar/Dry Creek 330 kV	2,800 MW	$1,746.3m
S4	Bolivar/Dry Creek 500 kV	7,000 MW	$3,515.8m

[93] The final name for the Bolivar/Dry Creek would be finalized once its final location is determined.

Option	Summary	Additional line capacity	Capital cost(s)
'End-to-end' options[94]			
S2 + N1	Highest NPV southern credible option paired with Bundey to Narcoona – 275 kV	2,000 MW (S2) 2,400 MW (N1)	$1,406.4m (S2) $1,726.8m (N1)
S2 + N2	Highest NPV southern credible option paired with Bundey to Narcoona – 330 kV	2,000 MW (S2) 2,800 MW (N2)	$1,406.4m (S2) $2,045.3m (N2)
S2 + N3	Highest NPV southern credible option paired with Bundey to Narcoona – 500 kV	2,000 MW (S2) 7,000 MW (N3)	$1,406.4m (S2) $3,857.7m (N3)
S2 + N4	Highest NPV southern credible option paired with Bundey to Narcoona – staged 500 kV	2,000 MW (S2) 2,200 MW (N4 Stage 1) 7,000 MW (N4 Stage 2)	$1,406.4m (S2) $2,857.6m (N4 Stage 1) $1,436.3m (N4 Stage 2)
Standalone northern option			
N1	Northern component of best performing 'end-to-end' combination	2,400 MW (N1)	$1,726.8m (N1)

All options are assumed to have annual operating and maintenance costs that are 1 per cent of the capital costs for all assets. ElectraNet considers this typical for projects of this scale.

ElectraNet anticipates that all options will be considered by AEMO in the 2026 ISP, as they are all reflected in the 2025 AEMO Electricity Network Options Report.[95]

4.4 Options considered but not progressed

A number of additional network options have been considered over the course of preparing this PADR, and in the associated earlier 2024 ISP assessment(s). These additional options, and the reasons they have not been progressed, are summarised in the table below.

The consideration of non-network options is outlined above in section 3.

[94] The site name of Narcoona might change when a more precise location for this site is determined

[95] While each option is reflected in the 2025 AEMO Electricity Network Options Report, the PADR options involve minor scope refinements since those options were finalised, i.e., the southern solutions now go to a new site near Bolivar/Dry Creek (as opposed to Globe Derby), and the northern solutions go to Narcoona (as opposed to Cultana).

Table 11: Alternative options considered but not progressed

Option	Reason(s) it has not been progressed
Southern solutions	
275 kV d/c between Bundey and Para (1a from the 2024 ISP)	While the new line component of the draft 2026 ISP candidate option was included in the 2024 ISP as an alternate option on a standalone basis (i.e., without also disconnecting the existing Waterloo-Templers 132 kV line, building a 132 kV single-circuit line from Templers West to Templers and installing a 160 MVA, 275/132 kV transformer at Templers West, disconnecting the existing Para-Roseworthy 132 kV and an upgraded transformer at Robertstown), we do not consider it meets the identified need for this RIT-T on a standalone basis. Specifically, without the additional works, the 132 kV network will constrain the new line works and it will not be possible to use its transfer capacity. This has been determined by ElectraNet following additional network studies undertaken after the 2024 ISP.
275 kV d/c from Brinkworth to cut into Bungama Blyth West (1b from the 2024 ISP)	While this was included as an alternate option in the 2024 ISP, we do not consider it meets the identified need for this RIT-T as it does not alleviate the identified constraints. Specifically, additional modelling following the 2024 ISP has found that this option is not expected to assist with meeting the identified need for this RIT-T.
Bundey to Para 330 kV (or 500 kV) line	As outlined in section 4.1, we no longer consider the use of Para for NTx to be commercially feasible under the RIT-T due to the need to quarantine the existing spare bays for future expansion, and the elevated bushfire risk that comes with connecting new lines to Para under NTx. This is the case no matter what voltage is assumed, i.e., not just at 275 kV. In addition, we consider that a 330 kV or 500 kV Bundey to Para line would result in an immaterial difference in the additional transfer capacities for this route, compared to the 275 kV variant. These two variants are therefore also not considered commercially feasible relative to S1 given the significantly greater costs they would involve.
A staged 500 kV variant for the southern section	We have only investigated one staged 500 kV variant at this point due to the additional studies and computational analysis involved. The northern portion was selected for this investigation given there is a greater number of potential LILs that would trigger 500 kV north of Bundey, as opposed to south of Bundey. We may revisit this in the PACR.
Terminate the southern end of the section at an alternative existing site, such as Murray Bridge or Tailem Bend (instead of Para or Bolivar)	NTx is designed to transfer large amounts of power. The existing transmission lines at (or near) Murray Bridge or Tailem Bend do not have sufficient capacity to carry this additional power to metropolitan Adelaide, so new lines would be required. Connecting at either location—and then constructing new transmission lines to Adelaide—would increase project costs by at least 50%. In addition, any new line from these sites to metropolitan Adelaide would need to cross the Adelaide Hills, introducing high bushfire exposure and risk similar to the Para route. This would reduce the reliability of NTx and the security of supply to metropolitan Adelaide, and it would not improve network diversity.

Option	Reason(s) it has not been progressed
Undergrounding approximately 20 km of S2/S3	We have assessed versions of the S2 and S3 solutions that involve undergrounding the final approximate 20 km before Bolivar/Dry Creek. However, these versions are found to be significantly more expensive (i.e., multiples of the overhead cost[96]) and are not expected to result in commensurately greater market benefits (or cost savings) under the RIT-T. These versions are therefore not considered commercially feasible.
Undergrounding the southern section of NTx from Bundey to Bolivar	As per the item above the cost of this option would be several times of the overhead transmission line option. Additionally, HVAC underground cables are not a good technical and economical option for distances longer than around 40-70 km because of the need of additional reactive compensation. The estimated distance between Bundey and Bolivar is around 134 km. These factors make this option very expensive and technically complex. Hence, it is not expected to result in commensurately greater market benefits (or cost savings) under the RIT-T and it is not considered commercially feasible.
Use of submarine cables for portions of options between Bundey and a new site	While the use of submarine cable placements may solve certain problems associated with urban easements and visual impact to local communities, we consider that these variations are ultimately not technically or commercially feasible under the RIT-T. Specifically, ElectraNet considers that they would not be technically feasible due to marine sanctuary permission issues, and the significantly longer distances and difficulties associated with procuring and installing submarine cables would result in significantly greater costs (without an expected commensurate increase in benefits).
HVDC	The use of HVDC is not considered commercially feasible (even with HVDC point-to-point), as break-even distances compared with HVAC are usually above 400 kilometres (and the southern section only spans approximately 130-140 kilometres). There is also not expected to be a commensurate increase in market benefits from the use of HVDC technology. This option would also require ElectraNet to include HVDC technology into the assets that it operates and manages. This would mean introducing new knowledge and expertise, new life-cycle management, new type of spare parts, new training for maintenance and repair crews and others, with associated costs to ElectraNet. In addition, it would be very difficult to connect future customers to the transmission lines because of technological differences, and any intermediate connection would be technically difficult and very expensive.

[96] A study conducted in 2023 by the University of Queensland and Curtin University found that the indicative cost of underground HVAC is more than three times of a corresponding overhead transmission line.https://eecs.uq.edu.au/article/2023/11/comparing-high-voltage-overhead-and-underground-transmission-infrastructure-500kv

Option	Reason(s) it has not been progressed
Northern solutions	
HVDC	The link between Bundey and Narcoona is expected to unlock and facilitate the connection of new loads, generators and batteries from the Mid North region without present connections to our network, due to the large distances. Development of these new connections would not be possible with HVDC as it is mainly designed to transfer power point-to-point. Any intermediate connection will be technically very difficult and extremely expensive if HVDC is used. Given the total distance of the link (approximately 360 km), it is very likely HVDC will not be commercially feasible (even with HVDC point-to-point), as break-even distances compared with HVAC are usually above 400 kilometres. This option would also require ElectraNet to include HVDC technology into the assets that it operates and manages. This would mean introducing new knowledge and expertise, new life-cycle management, new type of spare parts, new training for maintenance and repair crews and others, with associated costs to ElectraNet.

4.5 Community support considerations

ElectraNet has undertaken comprehensive investigations and engagement to inform early planning and corridor selection for NTx, including consideration of community and stakeholder feedback on corridor options, costs, benefits, environmental factors, land use planning and land access. While these investigations and engagement are ongoing, the PADR extension granted by the AER has significantly enabled further progress of community engagement in relation to route selection to increase confidence in preliminary conclusions.

ElectraNet published a Community and Stakeholder Engagement Plan (CSEP) for NTx in June 2025.[97]

In undertaking these route development investigations and community engagement, ElectraNet has followed five Guiding Principles:

1. **Respectful and meaningful engagement** – we engage with stakeholders and communities to understand what matters and to inform our decision-making.
2. **Protecting land and place** – we protect what is environmentally, culturally and socially important.
3. **Delivering tangible benefits** – we deliver tangible benefits for local communities, customers and South Australia.
4. **Transparent decision-making** – We are transparent in our decision-making.

[97] ElectraNet, Community and Stakeholder Engagement Plan – 2025 Northern Transmission Project, June 2025 – available at: https://ntxproject.com.au/wp-content/uploads/2025/07/NTx-Engagement-Plan-external-June-2025-Final.pdf

5. **Value for money** – we deliver value for money solutions for South Australians and energy consumers.

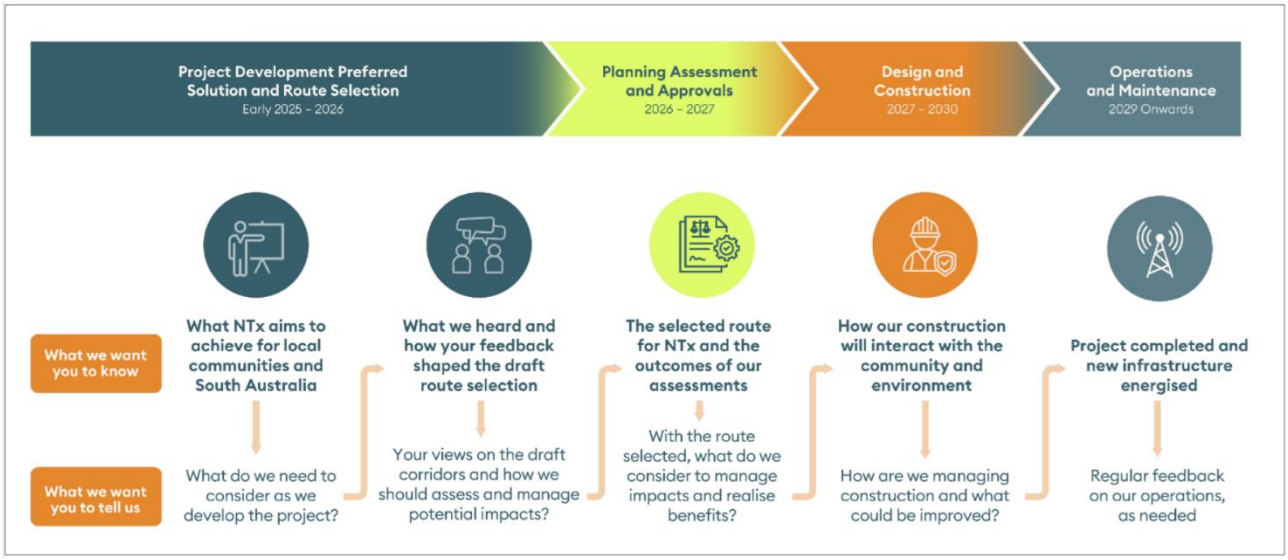
These principles are the backbone of the CSEP for NTx.

The objectives for the NTx community engagement are:

- community acceptance of a fair and transparent process;
- community awareness of ElectraNet's role in the clean energy transition, project justification, outcomes, risks, and benefits;
- strong and trusted relationships formed with local communities and businesses;
- community views are understood, and feedback is used to deliver a better project;
- engagement opportunities are accessible and inclusive for diverse audiences;
- communities are involved in creating and delivering lasting social, economic and environmental benefits;
- community engagement enhances ElectraNet's ability to deliver reliable and sustainable electricity services; and
- delivery of a social legacy that fosters community trust and support for the project and ElectraNet.

The CSEP outlines a staged approach to engagement that evolves as the project progresses as set out in Figure 18.

Figure 18: NTx engagement objectives and progression



4.5.1 Engagement activities

Consumer engagement

ElectraNet has been engaging with consumers about NTx since 2024. This has primarily been via ElectraNet's Consumer Advisory Panel (CAP) and the NTx Reference Group (NTx RG). The NTx RG consists of members of the CAP who report back to the CAP.

There have been six meetings of the NTx RG to date, and the NTx team has presented to seven meetings of the CAP. This represents a total of three additional engagements since December last year.

The PADR extension granted by the AER enabled us to present for a seventh time to the CAP. The original PADR publication date would not have enabled adequate levels of engagement with the CAP regarding PADR inputs and findings.

Engagement with the CAP and NTx RG has mainly focused on demand forecasts, cost estimation and community engagement activities, including inviting feedback on the engagement approach.

Community Engagement

At a high-level, key engagement activities have included:

- **Community stakeholder engagement in early-2025.**
  - In April 2025, three community stakeholder introduction workshops were held – one at Port Augusta, one at Burra and one at Gawler - to introduce NTx and begin a conversation with key community stakeholders within the project's study area.
- **Multi-criteria assessment (MCA) workshops in mid-2025**
  - During May and June 2025, six MCA workshops were held – two each in Port Augusta, Burra and Gawler[98] – involving representatives from local councils, landscape boards, Regional Development Australia, community groups, tourism and heritage bodies, environmental and conservation groups, and key agricultural and industry stakeholders.
- **Ongoing engagement and corridor refinement in late-2025**
  - An extensive engagement program was undertaken across the project region, concluding on 31 October 2025 and involving more than 50 community events, information sessions and pop-up engagements. These were supported by targeted meetings with local councils, landholders, Traditional Owners, regional organisations, industry representatives and community members.
  - An online survey attracting over 400 responses, 13 formal submissions and over 1,000 comments via the project's interactive map. Refer to Figure 19 for a summary of engagement activities undertaken during this period.

Traditional Owner engagement

We have also engaged with the six Traditional Owner groups that the project footprint will interact with:

- Kaurna people, represented by the Kaurna Yerta Aboriginal Corporation Registered Native Title Body Corporate (RNTBC).
- Ngadjuri people, represented by the Ngadjuri Nation Aboriginal Corporation RNTBC.
- First Peoples of the River Murray and Mallee Region #2, represented by the Mid Murray Aboriginal Council.
- Nukunu people, represented by the Nukunu Wapma Thura Aboriginal Corporation RNTBC.
- Ngadjuri, Adnyamathanha, and Wilyakali peoples, represented by the Ngadjuri

[98] Additional detail can be found at: https://ntxproject.com.au/mca-process/

- Adnyamathanha Wilyakali Native Title Aboriginal Corporation RNTBC.
- Barngarla people, represented by the Barngarla Determination Aboriginal Corporation RNTBC.

Figure 19: NTx engagement activities in 2025

To date, engagement has focused on sharing information about the project scope, introducing corridor options and initiating cultural heritage discussions.

This phase has enabled Traditional Owners to contribute cultural knowledge; identify preliminary areas of concern and influence how heritage and Native Title matters will be managed.

4.5.2 Progress against engagement objectives

ElectraNet is committed to reporting its progress against the objectives of the NTx CSEP. The CSEP will also be revised as the project progresses to ensure it remains fit-for-purpose and aligned with community expectations.

A summary of progress to date against the objectives is provided below.

Community acceptance of a fair and transparent process

ElectraNet has undertaken direct engagement with landholders, Traditional Owners, community members, councils and regional organisations to support transparent and inclusive decision-making.

Multiple electronic mailouts, project updates, fact sheets, a *What We Heard Report*[99], *Corridor Identification Report*[100] and *MCA Outcomes Report*[101] have provided consistent visibility of project progress and the rationale for decisions.

Ongoing dialogue through stakeholder meetings and enquiry channels has helped demonstrate that community views are being appropriately considered in decision-making.

As expected in the early stages of project development, some community questions have been raised about corridor selection and the approach to engagement. This feedback, and how it has been considered in project decision-making, has been provided in a second *What We Heard Report*, which will help respond to these early community questions.

Community feedback regarding the engagement approach and activities will be considered in when the CSEP is reviewed, in alignment with the outcomes of community engagement undertaken in late 2025 and detailed in the *What We Heard Report* that was released in April 2026.[102]

A comprehensive stakeholder relationship and issues management system has been established, supporting transparent tracking and response to community concerns.

Community awareness of ElectraNet's role in the clean energy transition, project justification, outcomes, risks and benefits

Awareness-building activities have included baseline sentiment and market research, regional information sessions, letters/project updates mailed to over 29,000 households and ongoing communication through digital platforms and local media.

These efforts have increased community understanding of ElectraNet's function within South Australia's electricity network.

Community participation in engagement activities has been strong, with high levels of interaction across digital and in-person channels.

The project has featured prominently in ElectraNet's social media communications and third-party posts, effectively directing stakeholders to engagement opportunities. This has helped build awareness of the project's purpose and contribution to ensuring South Australia's growing demand is met via a reliable, affordable and sustainable electricity supply.

Community views are understood and feedback is used to deliver a better project

Feedback mechanisms have been well-utilised, including:

- 1019 comments on the NTx interactive online map
- 412 respondents to the project survey
- 13 formal submissions
- 917 face-to-face conversations, and
- 792 email subscribers.

[99] NTx - Project Introduction Workshops - What we heard
[100] NTx Corridor Identification Report
[101] NTx MCA Outcomes Report
[102] NTx – What We Heard Report - Vol. 2 - April 2026

These insights have directly informed the project's development to date and will continue to shape future decisions. Community feedback is being acknowledged through *What We Heard* reports and embedded in the project's technical and planning processes.

In **NTx North**, feedback helped inform the selection of a Preferred Corridor in August 2025. Since then, engagement in this area has become more targeted, with landholder and Traditional Owner discussions focused on refining the proposed alignment. These conversations are influencing potential route adjustments, which could reduce property and heritage impacts as we continue to work constructively with potential host landholders. Broader community engagement will increase as the project progresses.

In **NTx South**, a different approach has been taken in direct response to the diversity of land uses and stakeholder priorities. Instead of selecting a Preferred Corridor in August 2025, the engagement period was extended to allow more time for conversations with local community and stakeholders and other investigations.

As a result of what we heard during this extended consultation period, ElectraNet expanded the study area and is now exploring land east of the initial corridor options. Early engagement is currently underway in these new areas to better understand land use requirements and assess whether a different corridor option could provide a better project outcome that's more aligned with community interests and priorities.

An initial *What We Heard Report* was published in June 2025, and a follow up draft *What We Heard Report* was published on 16 February 2026, containing the outcomes of engagement undertaken in the latter half of 2025. Comments on this draft closed on 16 March with the Final *What We Heard Report* recently released. These reports are a core part of our commitment to transparent engagement and demonstrate how feedback is being understood and informing both corridor selection and design development.

Importantly, the outcomes of this engagement and the feedback received demonstrated that whilst there was general support for the need for the project, there were also concerns in relation to the impact on farming communities, particularly in the northern parts of NTx South study area.

As a result, ElectraNet has explored potential new locations to the east of the initial corridor options consulted on. We have engaged with landholders in these new areas to better understand land use requirements and assess whether a different corridor option could provide a better project outcome that is better aligned with community interests and priorities. The next step here will be to engage more broadly with the community members in this new area to provide the chance for input in advance of ElectraNet selecting a preferred corridor though this area.

Key community interests and priorities are being used to inform the investigation and testing of alternative corridor options. Key themes were consistently raised across the study area and include:

- Farming and food security
- Bushfire risk
- Land value, business and compensation
- Health, safety and wellbeing

- Amenity, tourism and heritage
- Environmental impacts
- Project justification and alternative options
- Potential opportunities

These community interests and priorities are being used to direct investigations into alternative options beyond Goyder's Land and have been adapted into measurable metrics used to test and confirm the performance of corridor options. Community interests and priorities continue to be critical to the ongoing testing and refinement of options as the project progresses.

Engagement opportunities are accessible and inclusive for diverse audiences

Engagement has been designed to accommodate a broad cross-section of the community, with opportunities provided through online platforms, small group sessions, individual meetings and large-format public events.

A review of multilingual and culturally-diverse engagement requirements identified one key area where translation services could be beneficial, and these have been made available through local networks. Community feedback has been used to continuously refine both online and in-person engagement methods, with a virtual community forum planned for future stages.

Strong and trusted relationships formed with local communities and businesses

ElectraNet is in the early stages of building relationships with local communities and businesses, while progressing project decisions that may not be welcomed by all stakeholders, particularly those directly impacted. We acknowledge that levels of trust can fluctuate throughout the lifecycle of a project of this scale and complexity.

To support trust-building, we have prioritised early, consistent and transparent engagement. This includes using structured engagement tools, regular communications and ongoing updates to our stakeholder database. Our approach is designed to ensure stakeholders can see how the project is evolving, how feedback is being considered and how decisions are made.

While trust continues to develop, there are early signs of positive relationship-building. Stakeholder evaluation surveys conducted following the MCA process (May–June 2025) indicated strong appreciation for ElectraNet's collaborative approach and transparency.

Positive feedback has also been received from members of the Community Advisory Panel (CAP), the NTx Reference Group and individual MCA workshop participants.

We recognise that trust must be earned over time. To support this, ElectraNet will continue to report on how community and stakeholder input has informed project development, beyond the release of the second *What We Heard Report* in April 2026 and the intended release of a preferred corridor for NTx South following the additional investigations and engagement being undertaken.

The engagement strategy and approach will be reviewed taking into account stakeholder feedback, as part of our commitment to continuous improvement in practice.

Ongoing community sentiment tracking and systematic issues management are being implemented to support stronger relationships as the project progresses. These measures are intended to provide continuity and responsiveness as we move into the next phase of engagement.

Communities are involved in creating and delivering lasting social, economic and environmental benefits

Engagement has begun to identify community priorities for liveability and long-term benefit. A community benefit framework is being developed to support community-driven initiatives that align with project objectives.

ElectraNet will continue to engage with the local communities and stakeholders on the development of a community benefit framework. A local employment and business database linked to the ICN Gateway will also be established.[103]

Employment and skills workshops are planned in collaboration with early contractor involvement partners.

Awareness-raising through established local regional business networks has commenced and is ongoing. Further initiatives will continue to be explored as the project progresses and opportunities for delivery increase.

Community engagement enhances ElectraNet's ability to deliver reliable and sustainable electricity services

Early and widespread engagement has informed corridor development and strengthened ElectraNet's understanding of regional perspectives. Ongoing engagement will continue to support the project's development.

Project sentiment is being tracked through ongoing media monitoring, market research and online surveys, with assessments of project timing and delivery performance to be undertaken at key milestones.

These processes will ensure that engagement continues to support efficient project delivery and community confidence in ElectraNet's services.

Delivery of a social legacy that fosters community trust and support for the project and ElectraNet

Work to define and report against potential social contributions is ongoing, with the aim of ensuring that the project delivers lasting benefits to local communities. This includes consideration of opportunities for local procurement, skills development and regional participation aligned with ElectraNet's broader social value framework. Delivery of a social legacy will be informed and guided by our interactions with local communities to ensure alignment with community interests and priorities.

[103] The ICN Gateway is an online platform, part of the Industry Capability Network (ICN), that connects Australian and New Zealand businesses with major projects and procurement opportunities.

5 Ensuring the robustness of the analysis

Under the actionable ISP framework, the ISP directs the use of specific scenarios (and their weightings) for RIT-T assessments.

The options have therefore been assessed across three scenarios. The scenarios and assumptions feeding into them are sourced directly from those used in the draft 2026 ISP, updated only in a limited number of areas.

5.1 The assessment considers three 'reasonable scenarios'

The RIT-T is focused on identifying the top ranked credible option that maximises expected net benefits. However, uncertainty exists around aspects such as how quickly the energy transformation will occur, the scale of future distributed energy resource uptake, and the level of demand growth as other sectors electrify or consider use of alternate zero-emission fuels.

To deal with this uncertainty, the actionable ISP framework requires AEMO to direct the use of specific scenarios for each RIT-T. The costs and market benefits for each credible option are estimated across these scenarios and then weighted based on the likelihood-based weightings identified in the ISP for each scenario to determine a weighted ('expected') net benefit.[104] It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options in this PADR have been assessed under three scenarios – Step Change, Slower Growth and Accelerated Transition – consistent with the draft 2026 ISP.

The table below summarises the specific key variables that influence the net benefits of the options under each of the three scenarios, and shows any departures from the scenarios, as defined for the draft 2026 ISP, in bold. In particular, we have updated the assumptions adopted for:

- the expected retirement for Eraring Power Station (to align with the delay announced by Origin Energy on 20 January 2026),[105] and other changes to generation and storage projects (consistent with the latest AEMO generation spreadsheet available at the time the modelling inputs were finalised for this PADR);[106]
- the collective generation from the Riverland, Mid North SA, Yorke Peninsula REZ and net inflows from EnergyConnect, Heywood and Northern SA (the 'MN1 constraint' in the draft 2026 ISP);
- the location of new hydrogen loads (which are assumed in this PADR to all arise in Northern South Australia);
- how the South Australian Renewable Electricity Target has been modelled;
- how new entrant BESS are modelled in Central South Australia (specifically, the assumption that BESS connections within the Greater Adelaide region are uncapped); and

[104] AER, Cost Benefit Analysis Guidelines, August 2024, p. 58.
[105] https://www.originenergy.com.au/about/investors-media/origin-extends-eraring-power-station-operations-to-2029/
[106] Specifically, the January 2026 version of this spreadsheet.

- a 5 GW constraint on the development of new solar generation in northern SA (S5 REZ).

The delay to the expected retirement date for the Eraring Power Station represents a material change in fact compared to the draft 2026 ISP. It is reasonable to expect that this change will be reflected in the 2026 ISP, and it is therefore consistent with the AER's CBA guidelines on what constitutes a 'demonstrable reason' to vary the draft 2026 ISP assumption.

The other departures above represent assumptions/approaches that ElectraNet is currently advocating for AEMO to change in the 2026 ISP at the time of preparing this report. We consider that there is a good prospect that they will be updated by AEMO in the 2026 ISP, and so consider these changes are also consistent with the AER's CBA guidelines on what constitutes a 'demonstrable reason' to vary the draft 2026 ISP assumptions.

The 5 GW constraint on solar generation development in S5 REZ has been adopted as a proxy for a higher 'penalty cost' in developing solar generation in excess of this level. While we find that this constraint is not material in the core assessment (as it does not bind), ElectraNet intends to continue discussing the appropriate penalty cost with AEMO as part of the 2026 ISP process. We will align the PACR modelling with AEMO's 2026 ISP outcome on the appropriate penalty cost. This may also be further influenced by the effects of the events in the Middle East.

Table 12: PADR modelled scenario key drivers input parameters

Input parameter	Slower Growth	Step Change	Accelerated Transition
Electricity demand	2026 Draft ISP 'Slower Growth'	2026 Draft ISP 'Step Change'	2026 Draft ISP 'Accelerated Transition'
Generator and storage build costs	2025 IASR Slower Growth scenario (CSIRO GenCost Current Policies)	2025 IASR Step Change scenario (CSIRO GenCost Global NZE post 2050)	2025 IASR Accelerated Transition scenario (CSIRO GenCost Global NZE by 2050
Gas prices	2025 IASR 'Slower Growth'	2025 IASR 'Step Change'	2025 IASR 'Accelerated Transition'
Coal prices	2025 IASR 'Slower Growth'	2025 IASR 'Step Change'	2025 IASR 'Accelerated Transition'
Snowy 2.0	December 2028		
Torrens Island B	Retires 2026[107]		
Eraring	**Retires 2029[108]**		
Carbon budgets	2025 IASR	2025 IASR	2025 IASR

[107] We note AGL has recently agreed to extend the retirement of some of the units at Torrens Island B by two years, which will be incorporated into the modelling assumptions as a part of the PACR.
[108] See: https://www.originenergy.com.au/about/investors-media/origin-extends-eraring-power-station-operations-to-2029/

Input parameter	Slower Growth	Step Change	Accelerated Transition
Australia-wide target	82% share of renewable generation by 2030		
New South Wales Electricity Infrastructure Roadmap	12 GW of renewable generation capacity and 2 GW of long duration (at least 8 hours or more) storage capacity by 2030, as per 2026 Draft ISP 28 GWh of long-duration storage by 2034 (including the capacity constructed during the 2030 objective period)		
South Australia Renewable Target	**The 100% renewable target is modelled as enduring (whereas in the draft 2026 ISP it applies to 2027 only)**		
New entrant BESS in Central South Australia	**There is a cap of 1,050 MW on new entrant large-scale BESS capacity in the Central South Australia region (whereas in the draft 2026 ISP it is uncapped)**		
Victorian Renewable Target (VRET)	40% renewable share by 2025, 65% by 2030, and 95% by 2035, as per 2026 Draft ISP		
Victorian Energy Storage Target	2.6 GW by 2030 and 6.3 GW by 2035, as per 2026 Draft ISP		
Victorian Offshore Wind Target	2 GW by 2032, 4 GW by 2035 and 9 GW by 2040, as per 2026 Draft ISP		
Queensland Renewable Energy Target (QRET)	NA		
Tasmanian Renewable Energy Target (TRET)	15,750 GWh and 21,000 GWh of electricity generated from renewables in a calendar year by 2030 and 2040 respectively, as per 2026 Draft ISP		
The 'MN1 constraint' in the draft 2026 ISP	**The MN1 constraint assumed in the PADR modelling:** **[S2 generation] + [S3 generation] + [S4 generation] + [net flow from NSA to CSA] + [net flow to CSA through PEC] + [net flow to CSA through Murraylink] ≤ 1,100 MW** Whereas the formulation applied by AEMO in the draft 2026 ISP is: [S3 generation]+[S4 generation]+[net flow from NSA to CSA]+0.2×[net flow to CSA through PEC]≤1,630 MW		
Project EnergyConnect	FY2028		
Western Renewables Link	FY2030		
HumeLink	FY2028		
Hunter Transmission Project	FY2030		

Input parameter	Slower Growth	Step Change	Accelerated Transition
HCCt REZ Network Infrastructure Project	FY2029		
VNI West	FY2032		FY2031
Marinus Link (stage 2)	FY2035		
New England REZ Transmission	FY2032[109]		

5.2 Weighting the reasonable scenarios

Consistent with the draft 2026, the Step Change scenario has been given a 46% weight, with the Slower Growth and Accelerated Transition scenarios each being given a 27% weight.[110]

While these weightings have been applied in this PADR to weight the estimated market benefits and identify the preferred option across the scenarios, ElectraNet has also carefully considered the results in each scenario in Section 7 to better understand how differences in the future 'states of the world' impact the expected net benefits of the options.

ElectraNet considers that the Slower Growth demand forecasts are not realistic for South Australia as they include no LILs, which contrasts the strong connection interest we are seeing from these parties. We have therefore investigated a sensitivity that applies a zero percent weighting to the Slower Growth scenario to see how this affects the identification of the preferred option, as well as another that applies a higher assumed demand forecast to align more closely with the strong connection interest ElectraNet is currently facing from LILs (see sections 7.5.1 and 7.5.2, respectively).

5.3 Sensitivity analysis

In addition to the scenario analysis, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing. The range of factors tested as part of the sensitivity analysis in this PADR are:

- a zero per cent weighting applied to the Slower Growth scenario;
- higher assumed demand forecasts to align more closely with the connection interest ElectraNet is currently facing from LILs, as well as investigations into different assumed locations for LILs and the removal of the solar constraint;
- the higher estimated network resilience benefits estimated by KPMG;
- changes in option capex cost assumptions; and
- changes in the assumed discount rates.

[109] EnergyCo, New England REZ network infrastructure project – project update, April 2025. Available at https://www.energyco.nsw.gov.au/sites/default/files/2025-04/NE%20REZ%20project%20update%20April%202025%20accessible.pdf, accessible on 14 October 2025.
[110] AEMO, draft 2026, p. 9.

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

Where relevant, we have also estimated the 'threshold value' for key variables beyond which the outcome of the analysis would change. These results have informed the proposed re-opening triggers (as outlined in section 8.1).

6 Estimating the costs and market benefits

As facilitated by the extension to the PADR publication date, additional planning undertaken by ElectraNet has led to cost revisions compared to the estimates included in the 2025 AEMO Electricity Network Options Report. The change in costs of the options reflects a number of key developments that have affected the costs of transmission investments across Australia in recent years, as well as further planning works undertaken by ElectraNet. ElectraNet has provided the latest cost estimates to AEMO and expects these costs to be taken in account in the assessment for the 2026 ISP.

Gross market benefits have been estimated in-line with the AER Cost Benefit Analysis (CBA) Guidelines. Wholesale market modelling has been used to estimate these classes of market benefits.

6.1 Cost estimates

ElectraNet has prepared capital cost estimates reflecting estimates that are equivalent to the Association for the Advancement of Cost Engineering (AACE) cost estimate classification 'Class 4' for the options in this PADR.[111] The Class 4 estimates are of an expected accuracy of +50%/-30%.

The option capital cost estimates have been updated from those used in the draft 2026 ISP. The change in costs reflects a number of key drivers that have affected transmission investments in recent years, including increases in costs from increased global demand, supply chain disruptions and fluctuations in global commodity market prices for raw materials. We note that the increase in cost estimates since the 2024 ISP is consistent with the general increase in costs reflected in AEMO's most recent 2025 update to its Transmission Cost Database.[112]

The option cost estimates have also changed due to further planning works by ElectraNet, in line with the early works and stakeholder engagement ElectraNet has been progressing since the 2024 ISP.

The key influences on the cost estimates have been:

- General cost pressures
  - These reflect increasing:
    - demand for transmission augmentation across the NEM;
    - resource constraints;
    - prices for plant and equipment (both purchase and hire);
    - material costs;
    - requirements for management and supervision;

[111] The one exception to this is for Option S4, which has been estimated at level equivalent to a Class 5 level of estimate (as outlined in section 4.1).

[112] GHD Advisory, *ISP Transmission Cost Database Tool: 2025 Update*, 20 May 2025 – available at: https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-electricity-network-options-report/ghd-2025-transmission-cost-database-update-final-report#:~:text=Updates per cent20to per cent20asset per cent20building per cent20block,and per cent20relied per cent20on per cent20engineering per cent20judgement.

  - requirements for managing environment, heritage, safety, quality, and landowner requirements; and
  - levels of line deviations and line lengths to avoid or minimise on ground route impacts.
- The 2025 AEMO Transmission Cost Database commented on these rising cost pressures – namely:[113]
  - after accounting for inflation and updated inputs, cost estimates for overhead transmission lines have increased by approximately 25 per cent to 55 per cent (in real terms) compared with the cost estimates used in the draft 2026 ISP; and
  - for transmission substation projects, the increase is more modest, estimated at around 10 per cent to 35 per cent in real terms relative to the same baseline.

- Further planning undertaken by ElectraNet, supported by the early works funding provided through the initial early works CPA, which has led to project-specific cost increases:
  - This includes additional costs to construct the Bolivar/Dry Creek options (Options S2-S4), such as:
    - land required to host a new substation;
    - easements through areas where land values have increased substantially in recent years;
    - additional line length required, and civil works complications due to the site being close to the shoreline; and
    - expected geotechnical conditions.

While ElectraNet factored these influences into the cost estimates provided to AEMO as part of the 2025 Electricity Network Options Report, we note that cost estimation, including accounting for the impacts of the above influences, is an on-going process. The cost estimates presented in this PADR are therefore more refined, and are above, those included in the 2025 Electricity Network Options Report.

ElectraNet has developed, and will continue to refine, cost estimates considering these changed conditions and has commenced early contractor engagement to validate the cost estimates that have been prepared. This is a currently ongoing process, and it is expected the estimate accuracy will be refined over the contractor engagement period. The current cost estimates have been provided to AEMO and ElectraNet expects these costs to be taken in account in the assessment for the 2026 ISP.

All cost estimates have been prepared in 2024/25 dollars based on the information and pricing history available to ElectraNet at the time that they were estimated.

[113] GHD Advisory, *ISP Transmission Cost Database Tool: 2025 Update*, 20 May 2025, pp. i-ii.

6.1.1 Early works

ElectraNet received AER approval in June 2025 for contingent project funding[114] (CPA1a) for early works. The funding of $45.7 million has covered costs for stakeholder engagement, land use planning and acquisition, project development and procurement activities.[115]

Consistent with clause 5.16A.7(c) of the NER, we have excluded the approved early works costs incurred to-date from the cost estimates presented and used in this PADR. This cost sums to $22.7 million and relates entirely to activities under the AER-approved CPA amount for CPA1a.

In addition, and consistent with clause 5.16A.7(c) of the NER and section 4.3.4 of the CBA Guidelines, all early works costs that have been incurred to-date under CPA1a relate to assets that cannot be sold or utilised to support other projects, as these are specific to NTx and generally not reusable on other projects. These costs are therefore considered sunk.

The remaining AER-approved amount under CPA1a, and any potential future CPA (if applicable) funding, have been included in the cost estimates in this PADR as they are not considered sunk.

In preparing the PACR, we will re-evaluate which of the costs incurred under CPA1a and any potential future CPA (if applicable) have been incurred at that time and cannot be sold or utilised to support other projects. These sunk costs will be excluded from the PACR assessment, in line with NER 5.16A.7(c) and the AER CBA Guidelines.

Overall, all early works costs have contributed to substantial progress of the RIT-T, community engagement, cost estimation and ensuring timely project delivery. Specifically, the early works costs have contributed to a wide range of activities, including:

- RIT-T:
  - Progress market benefits analysis, network planning and scoping and network capability assessment including various studies to ensure optimum outcomes.
- Stakeholder engagement:
  - Undertake stakeholder and community engagement to inform project development and build social acceptance for the project.
- Cost estimation:
  - Determine the prudent and efficient costs to complete early works including ongoing community and stakeholder engagement, progressing all approvals, easement acquisition, scoping, undertaking design and planning procurement of long lead-time materials.
  - Identify, explore and manage the project risks, which will allow us to mitigate and/or diversify the project's risks so that the residual risk costs included in our Stage 2 contingent project application (which will include the bulk of the project's costs) are as low as possible.

[114] AER, ElectraNet Mid North South Australia REZ Expansion Stage 1a Early Works Contingent Project Application, Determination, June 2025.
[115] AER, *ElectraNet Mid North South Australia REZ Expansion Stage 1a Early Works Contingent Project Application*, Determination, June 2025.

  - Plan commencement of Early Contractor Involvement (ECI) engagement to develop and validate the prudent and efficient construction cost for the Stage 2 application.

- Ensuring timely project delivery:
  - Project initiation, including planning and design activities needed to accurately define the project, including pre-contracting activities for engineering, procurement and construction contracts such as obtaining binding bids.
  - Route selection including constraints mapping, multi-criteria assessments, stakeholder engagement and field surveys to identify a preferred corridor.
  - Identification and commencement of all primary planning and environmental approvals including consultation with State and Federal agencies, State development approval and preparation of a Federal EPBC referral, including activities on the critical path and in order to achieve the earliest practical delivery date.
  - Engagement with Traditional Owners including commencement of cultural heritage agreements and field surveys and Native Title negotiations.
  - Land acquisition and planning to support route identification, field surveys, geotechnical investigations, substation site selection, easement acquisition and preparation of Site Access Licences with landowners.
  - Engineering scoping and actively managing risk via early identification and mitigation to ensure efficient and timely project delivery.
  - Plan commencement of ECI engagement to develop timely and efficient construction schedules and delivery methodologies for Stage 2 to ensure the earliest possible project delivery.
  - Progress plans for environmental offsets including assessment of potential offset locations with early engagement of stakeholders to ensure efficient and timely establishment of likely offset agreements.

6.1.2 Substations and lines

ElectraNet approached external contractors for early expressions of interest (EOIs) for the expected preferred option. The external contractors provided budget design and construction pricing as part of the EOI. This pricing has been incorporated into the PADR revised project estimates.

For the other options, ElectraNet requested external estimates from an estimating consultant with a proven track record for similar estimating support with other TNSPs.

The estimates have been developed using the single-line diagrams (SLDs) and site layout drawing as the primary scope definition inputs. The cost build-up includes:

- direct costs, including allowances for design and construction, provided by contractors through the EOI process and/or estimating consultant inputs;
- plant costs based on ElectraNet period contract rates for switchgear and supplier budget estimates for major plant items;
- contractor delivery costs provided by contractors through an EOI process and/or estimating consultant inputs;

- ElectraNet delivery costs applied as a percentage of total construction costs; and
- a contingency allowance set at 10% of the total cost at this stage (which we consider appropriate for this stage of the estimating process).

6.1.3 Property/land access/easements

Land and easement costs were estimated using a consistent, systematic, and market-based methodology. A defined project corridor was mapped using geospatial analysis to accurately identify affected land parcels and the extent of impact on each property. Compensation estimates were then developed in accordance with the Land Acquisition Act 1969 (SA) and reflect all relevant statutory heads of compensation, including the value of the land interest acquired, impacts on the remaining land, and allowances for associated disturbance and professional costs.

Land values were informed by analysis of recent comparable sales and adjusted to reflect land use and planning controls. For each individual property, an adopted value rate was applied to the area affected by the easement and related impacts. Allowances for impacts on the balance of land were applied using consistent criteria that consider the presence of buildings or improvements and the lawful use of the land.

While these compensation estimates have been prepared using a detailed, consistent, and robust methodology, they are indicative only and do not replace the requirement for sworn valuations prepared by an independent, appropriately qualified valuer. These will be obtained when negotiations commence with affected landholders for the purchase of sites and easements.

ElectraNet expects to also incur costs relating to the provision of community benefit projects, as part of our partnership with affected communities (discussed in section 4.5.2). These include activities such as environmental and cultural heritage initiatives, enhanced stakeholder engagement and communications and local procurement. These activities and costs are currently being refined and will be reflected in the PACR assessment. However, they are not expected to affect the findings of the RIT-T given the sensitivity assessment that has demonstrated robustness of the outcome to material changes in network capital costs (see section 7.5.4).

6.2 Expected market benefits from expanding transfer capacity

The key benefits expected from increasing the transfer capacity of the transmission network in the Mid North are driven by anticipated changes in wholesale market outcomes going forward as Australia transitions to net zero by 2050.

Under NER 5.15A.3(b)(4), when applying the RIT-T to an actionable ISP project, the RIT-T proponent must quantify all classes of market benefits identified in the relevant ISP and may also consider other classes of market benefits in accordance with the CBA Guidelines.

The classes of market benefit included in the draft 2026 ISP were:[116]

[116] AEMO, draft 2026 ISP, p. 48.

- capital expenditure:
  - generator, storage and electrolyser capital deferral
  - retirement costs
  - REZ investment
  - system security costs
- operating and maintenance expenditure:
  - fuel cost savings
  - fixed operating and maintenance cost savings
  - variable operating and maintenance cost savings
- distribution expenditure (capital and operating costs);
- voluntary and involuntary load shedding reductions; and
- emissions reduction benefits.

These benefit categories are all assessed in this PADR, and have been estimated consistently across all options using wholesale market modelling (as outlined in section 6.3).

The one exception is for distribution expenditure, which has not been modelled as we do not consider it proportionate to do so at this stage. Specifically, while additional analysis is required by ElectraNet to further understand the magnitude of any such benefits, we do not consider that their inclusion would be materially different across the options (and we note that AEMO finds this category of market benefit relatively small, or non-existent, for all projects reported on in the draft 2026 ISP). We may revisit this in the PACR.

For each scenario described in section 5.1, the CBA Guidelines require classes of market benefits to be calculated by comparing the 'state of the world' in the base case where no action is undertaken, with the 'state of the world' with each of the options in place, separately. The 'state of the world' is essentially a description of the NEM outcomes expected in each case, and includes the type, quantity and timing of future generation and storage investment as well as unrelated future transmission investment (for example, that is required to connect REZs) and other transmission projects on the ODP.

6.3 Wholesale market modelling has been used to estimate market benefits

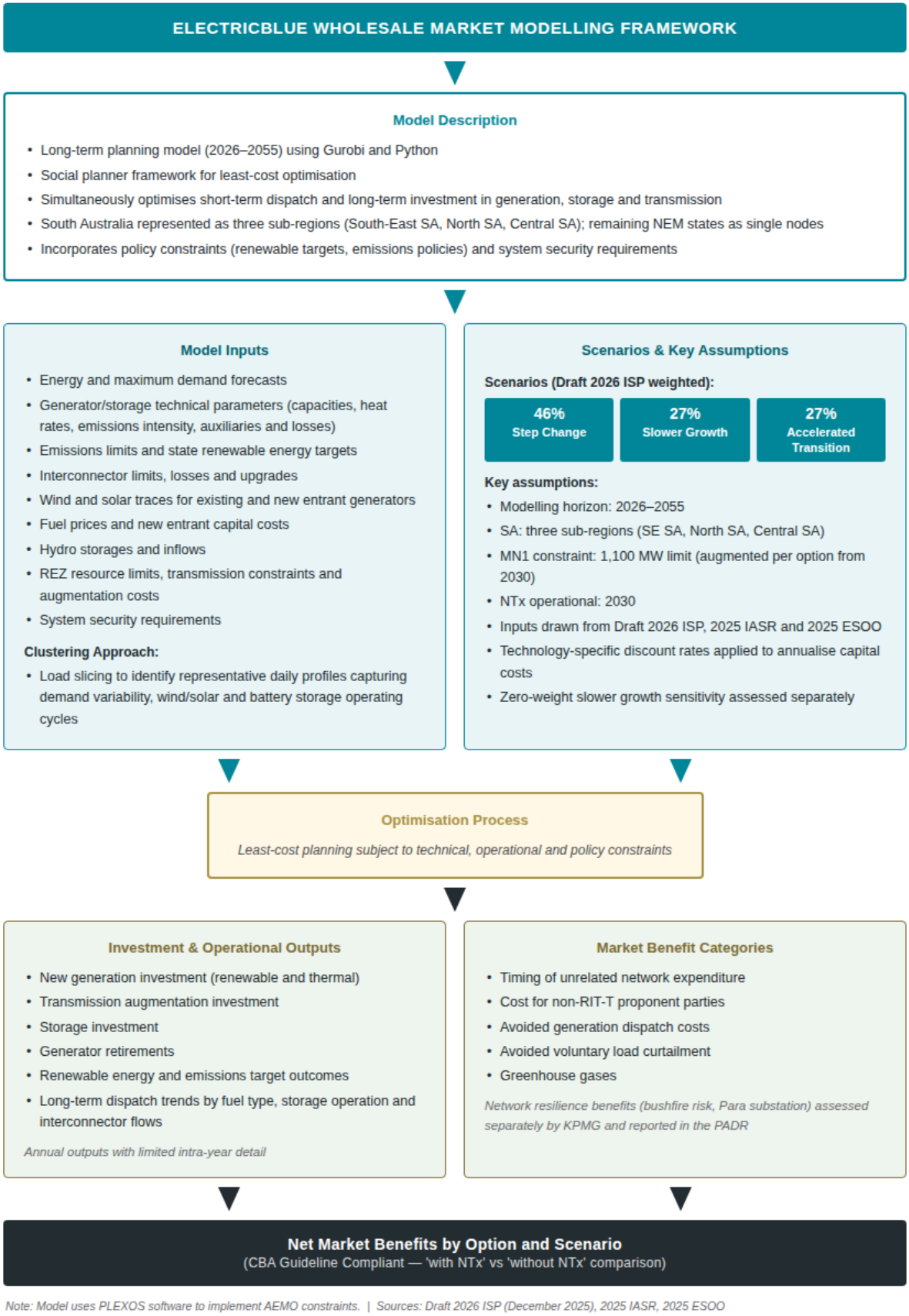
This section provides an overview of the wholesale market modelling that has been used to estimate the market benefits in this PADR. Additional detail can be found on the assumptions and methodologies applied in the separate HoustonKemp market modelling report released alongside this PADR.

6.3.1 Modelling overview

Wholesale electricity market modelling has been used to estimate the market benefits that each option provides under each scenario. This modelling was conducted by HoustonKemp, in alignment with the CBA Guidelines and is consistent with the capacity outlook modelling applied by AEMO in the analysis underpinning its draft 2026 ISP.

A summary of the market modelling framework is provided in the figure below.

Figure 20: Summary of the wholesale market modelling framework applied



Note: Model uses PLEXOS software to implement AEMO constraints. | Sources: Draft 2026 ISP (December 2025), 2025 IASR, 2025 ESOO

The modelling process applies optimisation techniques to develop a 'least-cost' plan for the development of the NEM. A least-cost plan involves projections of the generation, storage and transmission capacity required to meet demand over the modelling horizon at minimum cost, while satisfying policy, technical and system security constraints. The model simultaneously optimises the dispatch of generation and storage and the long-term investment in new generation, storage and transmission capacity.

The HoustonKemp modelling suite consists of a long-term planning and short-term dispatch model.

South Australia is represented as three sub-regions[117] covering nine REZs in the long-term modelling framework. Network constraints are represented as limiting the generation and storage capacity between the sub-regions and REZ. The benefits of NTx arise from alleviating these network constraints and enabling less costly generation and storage investments and operation across the REZ.

The long-term planning model takes into account expected half-hourly forecasts of energy demand and renewable energy supply over the modelling horizon. To make the model computationally tractable, yet still capture the key relationships between demand and variable renewable energy availability, the model applies a load block or 'slicing' approach to identify representative daily profiles that cover the range of system conditions.[118] This approach ensures that the variability in wind and solar PV and the daily operating profile of battery storage are incorporated into the long-term projection of investments.

6.3.2 Key model inputs

The long-term planning model projects generation, storage and transmission investments over the modelling horizon based on provided inputs and assumptions, which include:

- forecasts of energy demand and maximum demand;
- technical parameters for existing and new entrant generators/storage, eg, capacities, heat rates, emissions intensity factors, auxiliaries and losses;
- emissions and/or an emissions limit and state renewable energy targets;
- interconnector limits and losses and any future interconnector upgrades;
- wind and solar traces for existing and new entrant generators;
- fuel prices;
- new entrant capital costs;
- hydro storages and inflows;
- REZ resource limits, transmission constraints and costs for transmission augmentations; and
- system security requirements

[117] The three sub-regions modelled are the 'south-east region (SESA)', the 'central region' (CESA) and the rest of South Australia north of Adelaide (NSA).
[118] This involves applying a statistical technique known as 'clustering'.

These inputs and assumptions are primarily drawn from the 2025 IASR and draft 2026 ISP. Some key inputs and assumptions affecting the dynamics of investments and dispatch in South Australia have been updated, as summarised in Table 12.

The PADR extension granted by the AER enabled us to further understand and model a number of uncertainties.

6.3.3 Model outputs

The long-term planning model produces detailed outputs on an annual basis, including:

- investment in new generation, both renewable and thermal;
- investment in augmented transmission to support new generation;
- investment in storage;
- outcomes for renewable energy and emissions targets, both across the NEM and at a jurisdictional level;
- retirement of existing generators; and
- long-term trends in dispatch by fuel technology type, storage operation and interconnector flows.

Comparison of these detailed outputs between the 'with' and 'without' NTx modelling runs results in the estimates of each category of market benefits.

6.3.4 Network constraint representation

The model represents network constraints differently for the northern and southern NTx variants, reflecting the distinct network limitations each would address. Specifically:

- for the northern variants, flow between the Northern and Central SA regions (the CSA-NSA flowpath in the Draft ISP 2026) cannot exceed 1,070 MW without network augmentation, but the transfer capacity increase differs by the northern variant; and
- for the southern variants, the collective generation from the Riverland, Mid North SA, Yorke Peninsula REZ and net inflows from EnergyConnect, Heywood and Northern SA into Central CSA cannot exceed 1,100 MW without network augmentation, but the transfer capacity increase differs by the southern variant – these constraints have been updated from the draft 2026 ISP network representation, in which the capacity was 1,600 MW, due to updated analysis undertaken by ElectraNet that considers reduced capacity under contingency events. We believe this is the correct representation of the network constraint in for Mid North SA, and have been engaging with AEMO to incorporate this updated constraint in the 2026 ISP.

The table below sets out the REZs captured by this constraint and the network capacity for each option.

Table 13: REZ captured by the southern and northern constraints assumed

Section	Elements affected by constraint	Network capacity
Southern section	Generation in Mid North SA	1,100 MW
	Generation in Yorke Peninsula	
	Generation in Riverland	
	Net inflows from EnergyConnect	
	Net inflows from Heywood	
	Net inflows from Northern SA	
Northern section	Flow between Northern and Central SA	1,070 MW

6.3.5 Base case constraints

The base case for the PADR modelling includes the preferred option from the recently completed Eyre Peninsula Upgrade RIT-T, i.e.:

- a Yadnarie North substation to enable upgrading of the transmission lines between Yadnarie and Cultana to 275 kV operation; and
- establishing a new site close to Davenport and duplicate the Davenport to Cultana 275 kV circuits.

While this represents a key difference to the draft 2026 ISP modelling, we expect AEMO to reflect it in the 2026 ISP given the RIT-T is now complete.

6.4 Network resilience benefits have also been estimated

ElectraNet engaged KPMG as an independent consultant to undertake system risk studies regarding the bushfire risk around the Adelaide Hills, which found that the corridor going to the new site around Bolivar/Dry Creek delivers material network resilience benefits compared to connecting to Para.

A major bushfire event in the Adelaide Hills could materially impact the operation of the Para and Tungkilllo substations, which is critical for the operation of the electrical network around Adelaide. A bushfire event that affected Para operations could limit the capacity of the network to supply Adelaide and raise the risk of substantial unserved energy.

The impact of a bushfire event in the Adelaide Hills would be more critical if NTx connects to Para, as the power transfer via the site will increase with the connection of two more circuits.

Connecting to a new site around Bolivar/Dry Creek (under S2-S4) provides resilience benefits, as it would reduce the risk of unserved energy by not increasing the power transfer at Para, and would instead create a new hub around Adelaide.

KPMG have estimated the avoided unserved energy for Option S2 via climate-hazard, asset-failure and outage-risk modelling, then valued this using the AER Value of Customer Reliability (VCR) for outages. Option S1 is assumed to delivers no such benefits as its climate hazard exposure and outage risk profile are assumed to be the same as the base case, given Para represents a single source of failure.

The estimated avoided unserved energy for Option S2 has been included in the PADR assessment alongside the market benefits estimated via the wholesale market modelling (i.e., that shown in section 7) and is considered additive to the avoided unserved energy estimated through that exercise (i.e., there is no double-counting of avoided unserved energy). A proportionate assumption has been made that this expected benefit is the same for all options that go to the new site near Bolivar/Dry Creek and that it is the same in all three ISP scenarios.

While KPMG have estimated the network resilience benefits for two separate cases, we have applied their 'moderate climate change scenario' estimate in the core PADR assessment. Their 'high climate change scenario', which results in greater estimated network resilience benefits, has been included as a sensitivity (see section 7.5.3).

KPMG also comment on a number of indirect societal and economic benefits of going to a new site around Bolivar/Dry Creek, compared to Para, given the lower expected power outages. These benefits have not been quantified in this PADR. These include flow-on disruptions, public transport shutdowns, delayed emergency services, health impacts and broader community-wide welfare losses which were valued between $1.5 and $73.9 million, depending on the outage duration.

The KPMG report has been released alongside this PADR.

6.5 Relationship to ElectraNet's enterprise climate risk framework

The climate resilience analysis presented in this PADR has been undertaken to inform the assessment of credible options under the RIT-T and is project specific in scope and purpose. It is not intended to represent ElectraNet's enterprise-wide climate risk profile or its climate-related financial disclosures under Australian Sustainability Reporting Standards.

Climate modelling for NTx focuses on hazard-specific physical risks and asset performance, using the best -available datasets to translate climate exposure into asset failure risks and economic outcomes, consistent with the requirements of the RIT-T and AER cost-benefit analysis guidelines.

ElectraNet's enterprise climate risk assessment, including scenario selection, time horizons and risk aggregation, is undertaken separately and disclosed through ElectraNet's Sustainability Report and supporting governance processes.

6.6 The benefit from avoided intra-regional transmission investment for the northern solutions has not been estimated

ElectraNet's network modelling shows that the northern solutions are expected to avoid substantial network investment that would otherwise be needed in the Upper North region to connect additional LILs.

The benefit of avoiding this investment has not been included in the PADR analysis as, at this stage, we do not consider it proportionate to comprehensively model and include this benefit (that is, given all the options involving the northern solutions are found to be strongly net negative in the NPV assessment).

That said, we expect that this benefit category would become important should electricity demand within South Australia be higher than currently anticipated by AEMO in the draft 2026 ISP. This could be as a consequence of several major loads becoming more likely to connect to our network over the next few years.

We intend to assess further, and potentially include, the market benefit from avoiding this investment in the PACR.

6.7 Avoided mine connection costs for the northern solutions have not been modelled

In engaging with mining companies looking to develop mines north of Adelaide, it has been communicated to us that the northern options would significantly lower the cost of connecting these proposed new mines to the transmission network. This was highlighted in the recent submission to the draft 2026 ISP made by Magnetite Mines, which notes that a northern option would significantly reduce transmission infrastructure duplication, with corresponding reductions in land disturbance and environmental impact, and reduce the Razorback Project's capital expenditure profile by an estimated $150-200 million.[119]

While we have not modelled any avoided costs for future mining connections as part of this PADR, we may do so as part of the PACR (and any such analysis would adjust for the probability of mining load emerging in the future).

6.8 General cost benefit analysis parameters adopted

6.8.1 Assessment period

The PADR analysis considers a 25-year assessment period from 2025/26 to 2049/50. This period is consistent with the generation and storage outlook publication in the draft 2026 ISP modelling.

6.8.2 Annualised capital cost

Consistent with the methodology for the 2026 ISP, we have converted all capital costs for the options into an equivalent annual annuity. This allows like-for-like comparison on assets with different economic lives and different commissioning dates (and avoids needing to explicitly model benefits beyond the end of the assessment period).[120]

In calculating this annuity, we have adopted the technology-specific weighted average cost of capital (WACC) estimate for regulated transmission included in AEMO's 2025 IASR. Specifically, we have adopted an assumed 3 per cent WACC for regulated transmission investments in the

[119] Magnetite Mines, *Submission to the Draft 2026 ISP*, 13 February 2026, p. 2.
[120] AEMO, *ISP Methodology*, June 2025, pp. 94-95.

Step Change and Slower Growth scenarios, and 3.5 per cent for the Accelerated Transition scenario.[121]

The market modelling aligns with the methodology used for the 2026 ISP (with different annualised WACCs applied to different technologies).

6.8.3 Discount rate

The CBA Guidelines require the discount rate used in the NPV analysis to be the commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. A central discount rate of 7 per cent (real, pre-tax) has been used in the NPV analysis, consistent with the commercial discount rate in the 2025 IASR.

The RIT-T also requires that sensitivity testing be conducted on the discount rate and that the regulated WACC be used as the lower bound. ElectraNet has therefore tested the sensitivity of the results to a lower bound discount rate of 4.68 per cent,[122] and an upper bound discount rate of 10 per cent (being the upper bound in the latest 2025 IASR).

[121] AEMO, *2025 Inputs, Assumptions and Scenarios Report*, August 2025, p. 157.

[122] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (Basslink) as of the date of this analysis, see: AER, Feb 2026, Basslink - Determination 2026–30 – Final decision – PTRM.

7 Net present value analysis

This section presents the results of the NPV assessment of the options assessed, for each of the ISP scenarios and then also on a weighted basis. It also summarises the results of the sensitivity and threshold testing that has been undertaken to assess the robustness of the NPV results. The accompanying HoustonKemp market modelling report provides additional detail in terms of the modelled wholesale market impacts for each option, under each scenario.

7.1 Step Change scenario

The Step Change scenario is described by AEMO as achieving the objectives of Australia's government policies in transitioning the energy system, and reflects a scale of global and domestic action that limits global temperature rise to below 2°C compared to pre-industrial levels.[123]

Under these assumptions, Option S2 is the top-ranked credible option and is found to have estimated net benefits of approximately $363 million, in present value terms. Option S3 is also found to deliver positive net benefits under this scenario, but they are 37 per cent lower than for Option S2.

While Option S1 is also found to have positive net market benefits, this option is no longer considered likely (for the reasons outlined in section 4.1). Notwithstanding, it also ranks behind Option S2 (and Option S3).

The combination of all northern solutions with Option S2 is not found to be net beneficial in the Step Change scenario, and the standalone northern option (N1) is also not found to have positive net market benefits. The estimated net benefits of the northern options are influenced by a range of modelling assumptions and network interactions that are the subject of ongoing investigation ahead of the PACR. For example, the granularity of the network representation can reveal congestion and associated costs that affect the estimated benefits of a northern connection (see section 7.2), and assumptions regarding generation development in the northern REZ can also have a material bearing on outcomes (see section 7.5.2). ElectraNet will continue to work with AEMO to refine the inputs and assumptions underpinning the northern options analysis as part of the PACR process.

As outlined in sections 6.6 and 6.7, the benefits from any avoided intra-regional transmission investment and/or lower mine connection costs under the northern solutions has not been estimated at this stage and may be assessed further ahead of the PACR.

Figure 21 presents the estimated net benefits for each option under the Step Change scenario.

[123] AEMO, *2025 Inputs, Assumptions and Scenarios Report*, July 2025, p. 5.

Figure 21: Net market benefits under the Step Change scenario

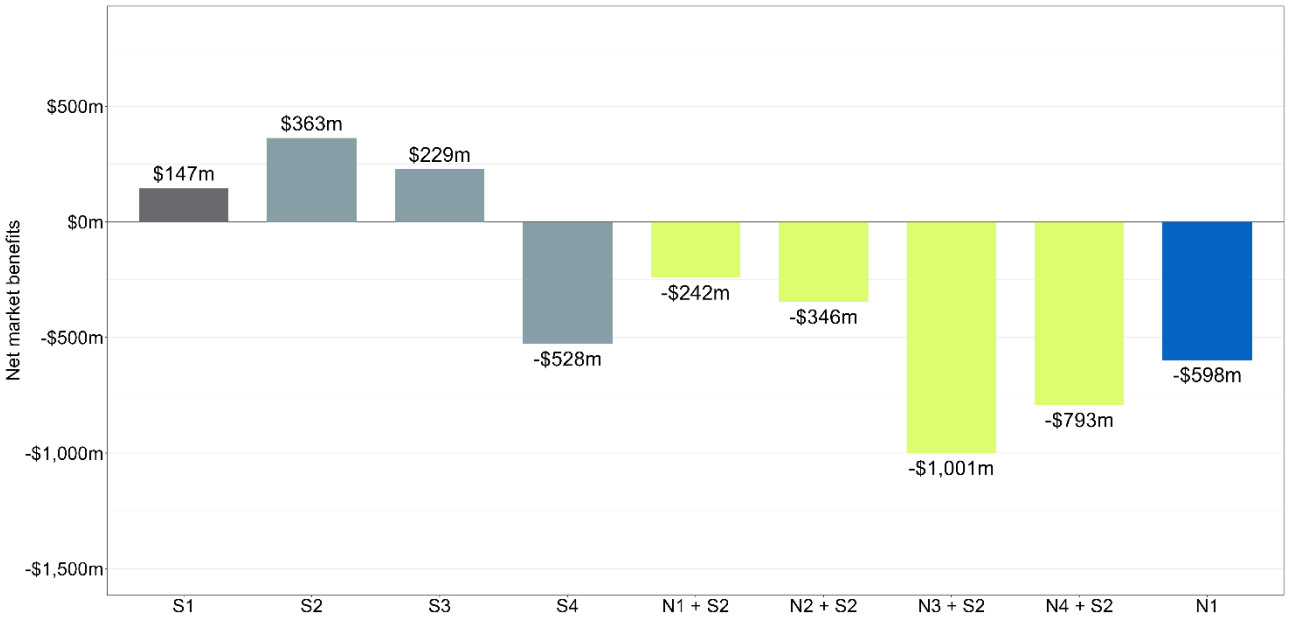
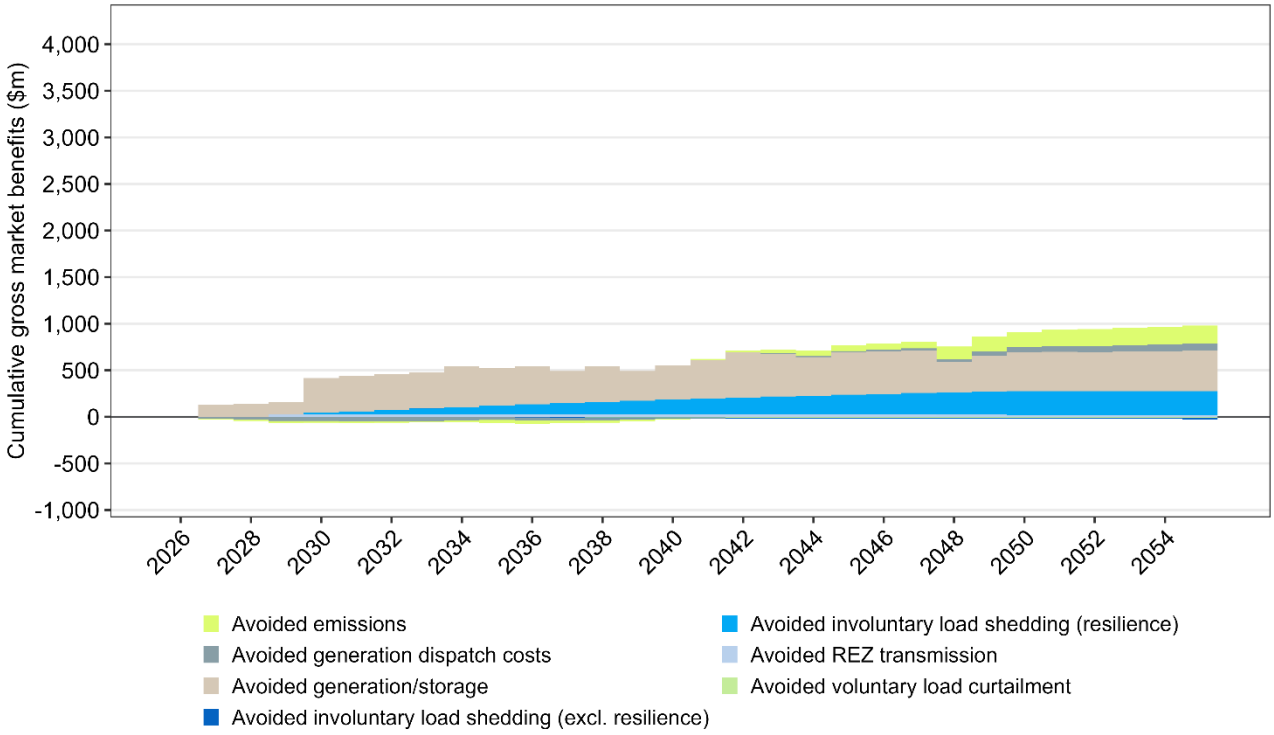


Figure 22 below presents the estimated cumulative expected gross benefits for Option S2 for each year of the assessment period under the Step Change scenario.[124] It shows that the main driver of the net positive results is avoided/deferred generation costs,[125] resilience benefits, avoided emissions, and avoided generation dispatch costs.

[124] This figure only presents the annual breakdown of estimated gross benefits for the preferred option. The separately released spreadsheet presents an annual breakdown of costs and benefits for all options. Since this figure shows the cumulative gross benefits in present value terms, the height of the bar in the last year (less the 'negative market benefits', i.e., those below the zero-line) equates to the gross benefit breakdown for Option S2 over the entire assessment period. This applies to all figures of this type in this PADR document.

[125] Despite avoided/deferred generation and storage being combined into a single benefit category in this figure, storage investment costs are slightly higher with NTx under the Step Change scenario and thus themselves represent a market cost compared to the base case.

Figure 22: Breakdown of cumulative gross benefits for Option S2 under the Step Change scenario



The key findings from the wholesale market modelling assessment of Option S2 under this scenario are:

- Avoided/deferred generation capital costs, as well as avoided emissions and dispatch costs are the primary sources of market benefit, providing approximately $455 million, $165 million and $55 million in gross market benefits, in present value terms, respectively.
- Avoided/deferred generation and storage capital costs (the beige sections of each bar in Figure 22) occur as early as 2025/6, with a sharp increase in 2029/30 (given the additional generation capacity unlocked in the Mid North region).[126]
    - In the first decade following commissioning, these savings arise primarily from avoided alternative renewable generation in the South East SA region.
- From 2040 onwards, benefits continue to arise from avoided emissions (the yellow sections of each bar in Figure 22), driven by the avoidance of gas generation capacity that would otherwise need to be built near Adelaide to meet growing South Australian demand in the absence of NTx.

[126] The category 'Avoided generation/storage' in the figure includes avoided generation capital costs, storage capital costs, fixed and variable operation and maintenance costs (FOM and VOM). FOM and VOM are included in this category for presentational purposes only. Where avoided generation or generation and storage costs are cited in the text, these figures refer to capital costs only and exclude FOM and VOM.

- Coinciding with the avoided emissions, and for the same reason, there is also a modest amount of avoided generation dispatch costs (the dark grey sections of each bar in Figure 22).
- Avoided emissions cost savings are less pronounced under the Step Change scenario than under Accelerated Transition and are comparable to the Slower Growth scenario. The dominant benefit throughout the analysis period stems from avoided alternative renewable generation capital costs.

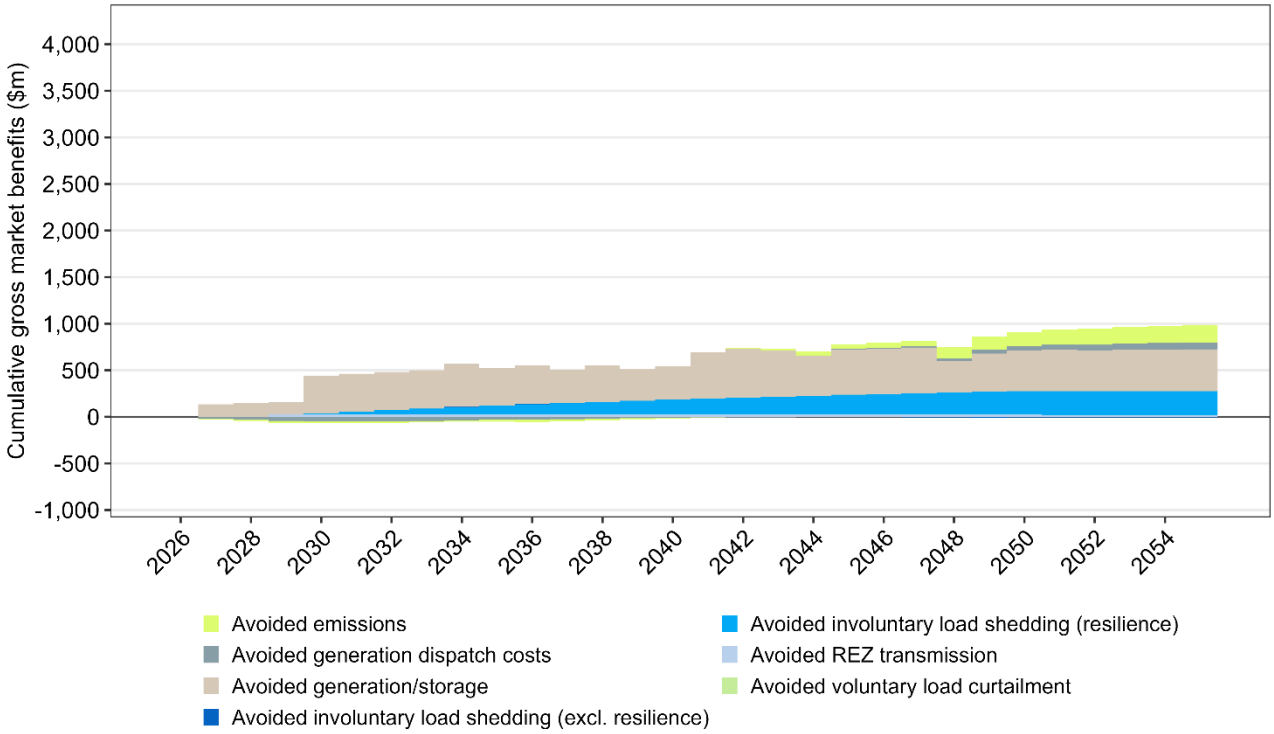
The network resilience benefits estimated by KPMG outside of the wholesale market modelling exercise are $250 million for Option S2, in present value terms.[127] These benefits arise from routing electricity through the proposed new Bolivar/Dry Creek substation rather than the existing Para substation, avoiding exposure to potential bushfire risks that could result in the loss of supply to a significant portion of Adelaide's load. These benefits are identical across all options and scenarios that assume the new site at Bolivar/Dry Creek as the resilience improvement is a direct consequence of the new connection itself (Options S1 and N1 therefore do not deliver these benefits as they do not include a Bolivar/Dry Creek connection).

Figure 23 below presents the estimated cumulative expected gross benefits for Option S2 combined with Option N1 for each year of the assessment period under the Step Change scenario.

While all combined options are found to have negative net market benefits at this point in time, we have presented the breakdown of the estimated market benefits of this combined option to show the incremental benefit arising from the northern option when the southern section is also upgraded.

[127] As outlined in section 6.4, a proportionate assumption has been made for the PADR analysis that all options going to the new site at Bolivar/Dry Creek involve these benefits (and that they are the same in all three ISP scenarios)..

Figure 23: Breakdown of cumulative gross benefits for Option S2 combined with Option N1 under the Step Change scenario



The modelling for the combined Option S2 + N1 shows that the addition of Option N1 contributes to an increase of around $17 million in gross market benefits, i.e., in addition to those arising from Option S2 alone. The majority of the incremental benefit arises from less storage capital costs as compared to Option S2. This additional benefit does not outweigh the costs of the N1 components, and the combined option is found to deliver negative net benefit overall.

In addition, the modelling of Option N1 alone shows that the incremental benefit from the combined option discussed above would not materialise without Option S2 also being developed. This is because the incremental renewable generation output in the Upper North (enabled by Option N1) would not be able to flow south to supply demand in Metropolitan Adelaide unless the southern network constraint is also alleviated by Option S2.

The gross market benefit for the combined Option S2 + N1 is larger than the combined gross market benefits of standalone Options S2 and N1. The additional market benefit comes from synergies created due to how the two upgrades interact.

7.2 Accelerated Transition scenario

The Accelerated Transition scenario is described by AEMO as achieving the objectives of Australia's government policies in transitioning the energy system, and providing an 'upside

alternative' that explores the possible drivers for rapid emissions reduction domestically and globally.[128]

Under these assumptions, Option S2 and Option S3 are found to deliver strongly positive net market benefits (in the order of $450-650 million). While Option N1 + S2 is also found to deliver positive net market benefits (of $90 million), it is 86 per cent lower than that estimated for Option S2, which shows that the incremental market benefits generated by the northern components do not justify the higher capital cost.

While Option S1 is also found to have positive net market benefits, this option is not considered likely (for the reasons outlined in section 4.1) and ranks behind Option S2 and Option S3.

Beyond Option N1 + S2, the other combined northern and southern options are not found to be net beneficial at this point in time, and neither is the standalone northern option (N1).[129]

Figure 24 presents the estimated net benefits for each option under the Accelerated Transition scenario.

Figure 24: Estimated net market benefits under the Accelerated Transition scenario

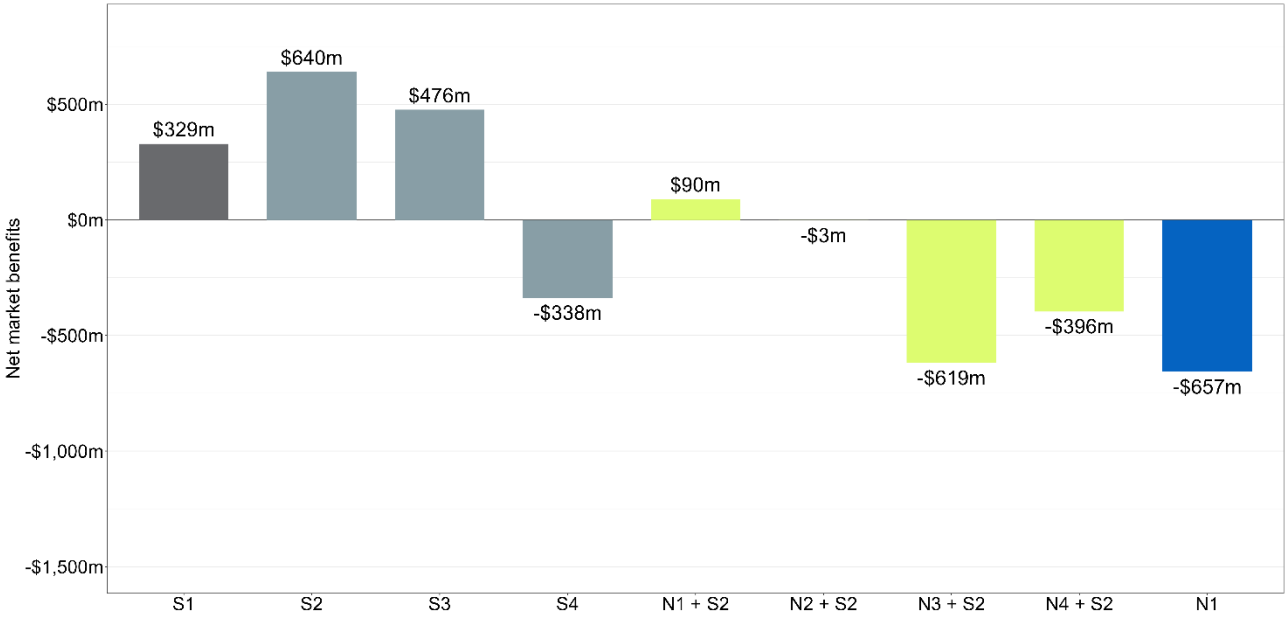
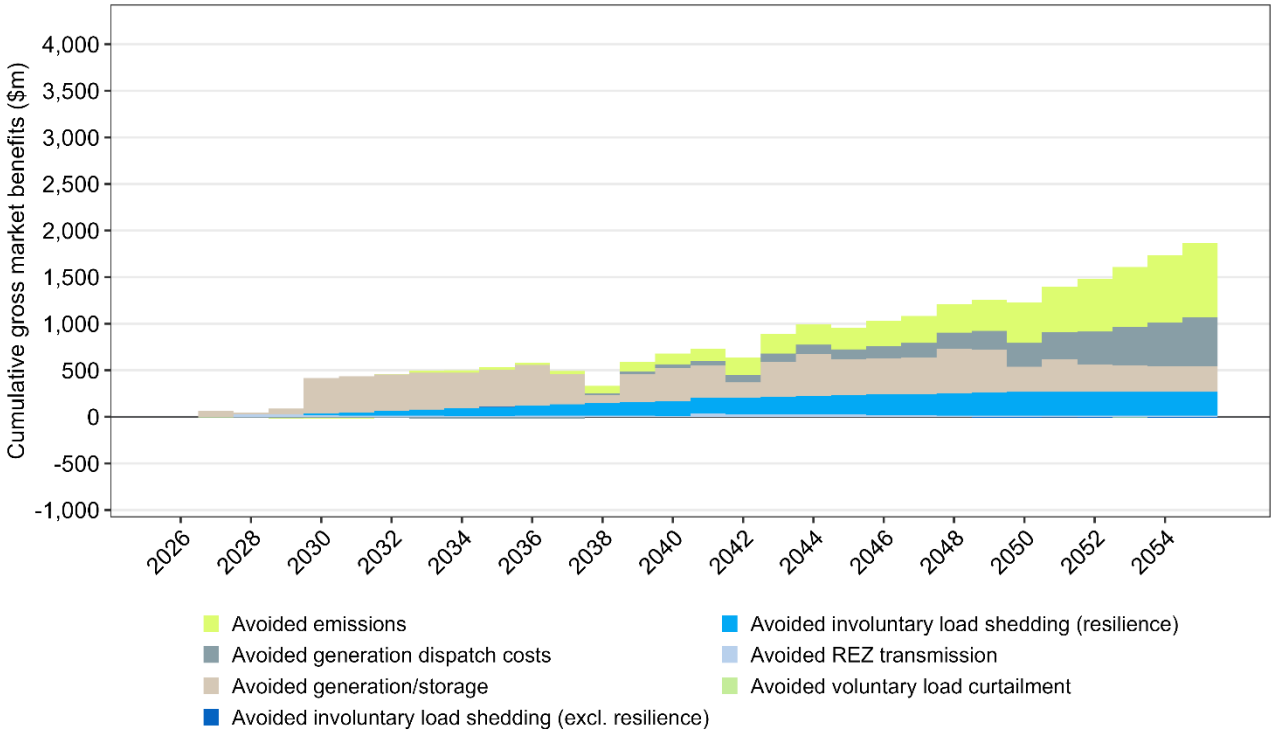


Figure 25 below presents the estimated cumulative expected gross benefits for Option S2 for each year of the assessment period under the Accelerated Transition scenario. The analysis finds that the benefits from avoided/deferred generation and storage capital costs accrue straightaway, whereas significant benefits from avoided emissions and dispatch costs begin accruing from the late 2030s and accrue steadily thereafter.

[128] AEMO, *2025 Inputs, Assumptions and Scenarios Report*, July 2025, p. 6.

[129] It is worth noting that the standalone northern Option N1 has zero estimated *gross* market benefits under the Accelerated Transition scenario, resulting in a lower *net* benefit outcome than under the Step Change scenario. This reflects the analysis period adopted aligning with the Draft 2026 ISP assumptions, which truncates the substantial gross market benefits for this option that arise beyond 2049/50. ElectraNet will work with AEMO to understand the post-2049/50 benefits of NTx further, and may include these in the PACR.

Figure 25: Breakdown of cumulative gross benefits for Option S2 under the Accelerated Transition scenario



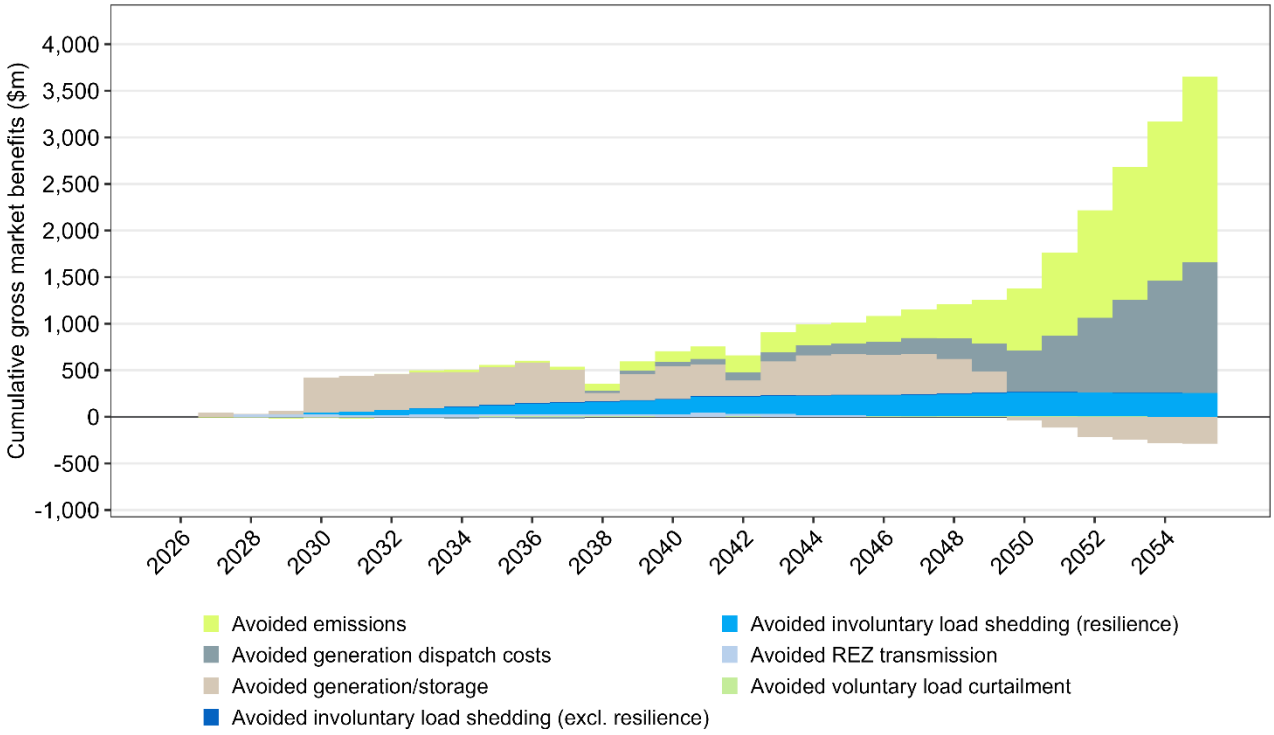
The key findings from the wholesale market modelling assessment of Option S2 under this scenario are:

- Avoided emissions, dispatch costs, as well as avoided/deferred generation and storage capital costs are the primary sources of benefit, providing approximately $433 million, $254 million and $214 million in gross market benefits, in present value terms, respectively.
- Avoided/deferred generation and storage capital costs arise from avoiding alternative renewable generation in South East SA, with the additional generation capacity in the Mid North region, as well as the Yorke and Eastern Eyre Peninsulas. .
- From the late 2030s onwards, avoided generation dispatch costs grow substantially, driven by the avoidance of gas generation capacity that would otherwise be required near Adelaide to meet South Australian demand in the absence of NTx.
    - This results in materially larger avoided emissions benefits compared to Step Change, as the emissions from that avoided gas generation are avoided.
- Avoided emissions costs begin earlier and are materially larger than that under the Step Change scenario, reflecting the higher gas generation that would otherwise be required under this scenario.

As outlined in section 7.1, the network resilience benefits estimated by KPMG outside of the wholesale market modelling exercise are approximately $254 million for Option S2, in present value terms.[130]

Figure 26 below presents the estimated cumulative expected gross benefits for the combined Option S2 + N1 for each year of the assessment period under the Accelerated Transition scenario. We have presented the breakdown of the estimated market benefits of this combined option to show the incremental benefit arising from the northern option when the southern section is also upgraded.

Figure 26: Breakdown of cumulative gross benefits for Option S2 combined with Option N1 under the Accelerated Transition scenario



The modelling for the combined Option S2 + N1 shows that the addition of Option N1 contributes to an increase of around $121 million in gross market benefits, i.e., in addition to those arising from Option S2 alone. While this option is found to have marginally positive net benefits under the Accelerated Transition Scenario, it is significantly lower than Option S2 alone and so the addition of Option N1 is considered to not be a net beneficial addition in the PADR modelling.

However, we consider that the benefits under the Accelerated Transition scenario are dependent on the assumed location of load and network representation. The box below outlines how ElectraNet's own internal modelling, which differs to the PADR's in this regard, finds that the northern solutions are net beneficial. The importance of the assumed location of load under the

[130] As outlined in section 6.4, a proportionate assumption has been made for the PADR analysis that all options going to the new site at Bolivar/Dry Creek involve these benefits (and that they are the same in all three ISP scenarios).

Accelerated Transition scenario is also discussed in a separate box as part of the high demand sensitivity in section 7.5.2 below.

Why ElectraNet's internal modelling finds that the northern solutions are net beneficial under the Accelerated Transition scenario

The Accelerated Transition scenario tests a future with high forecast demand. ElectraNet expects the demand will be centred on Adelaide and the Upper Spencer Gulf, with further meaningful growth happening in the Mid North and southeast of the state. The location of demand and scale are strongly influential in driving the need for transmission investment. These assumptions, when coupled with a highly detailed network representation reveal significant congestion in the transmission network that are not revealed in a national simplification of the South Australian transmission network. When congestion occurs, prices increase and additional high-cost generation like gas is constrained on to ensure power is delivered to where it needs to go. ElectraNet estimates NTx avoids approximately $448 million in fuel costs and accompanying emission costs of $539 million, both in present value terms.

The costs associated with system development including additional transmission, BESS and gas supply on the Eyre Peninsula are also underestimated in the base case and NTx avoids these additional investments. ElectraNet estimates that these costs are approximately $520 million in this scenario, in present value terms.

As a result, ElectraNet's detailed network modelling reveals higher investment and operational costs in this scenario in the base case and increased avoided costs with NTx of around $1,507 million in present value terms.

7.3 Slower Growth scenario

The Slower Growth scenario is described by AEMO as achieving the objectives of Australia's government policies in transitioning the energy system, and reflects domestic action to contribute to lesser global ambition to extend specific commitments to limit temperature rise. This scenario has lesser economic growth and greater challenges than other scenarios.[131]

The demand forecast used in this scenario includes no new LILs in it for South Australia over the assessment period.

Under these assumptions, Option S2 is the only credible option to have a positive net market benefit (albeit marginal), which is driven by the lack of LILs included in the demand forecasts. In light of this, and given the connection interest ElectraNet is currently seeing from these types of loads, we have investigated a sensitivity test that applies a lower weight to this scenario (see section 7.5.1).

Figure 27 presents the estimated net benefits for each option under the Slower Growth scenario.

[131] AEMO, *2025 Inputs, Assumptions and Scenarios Report*, July 2025, p. 5.

Figure 27: Net market benefits under the Slower Growth scenario

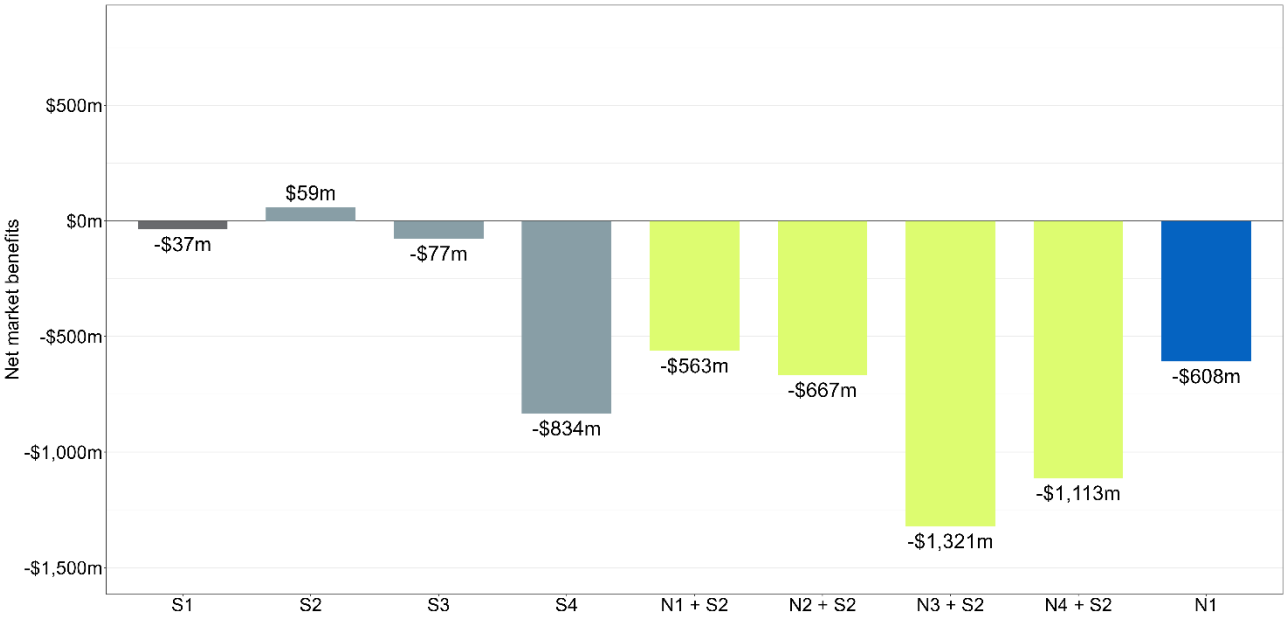
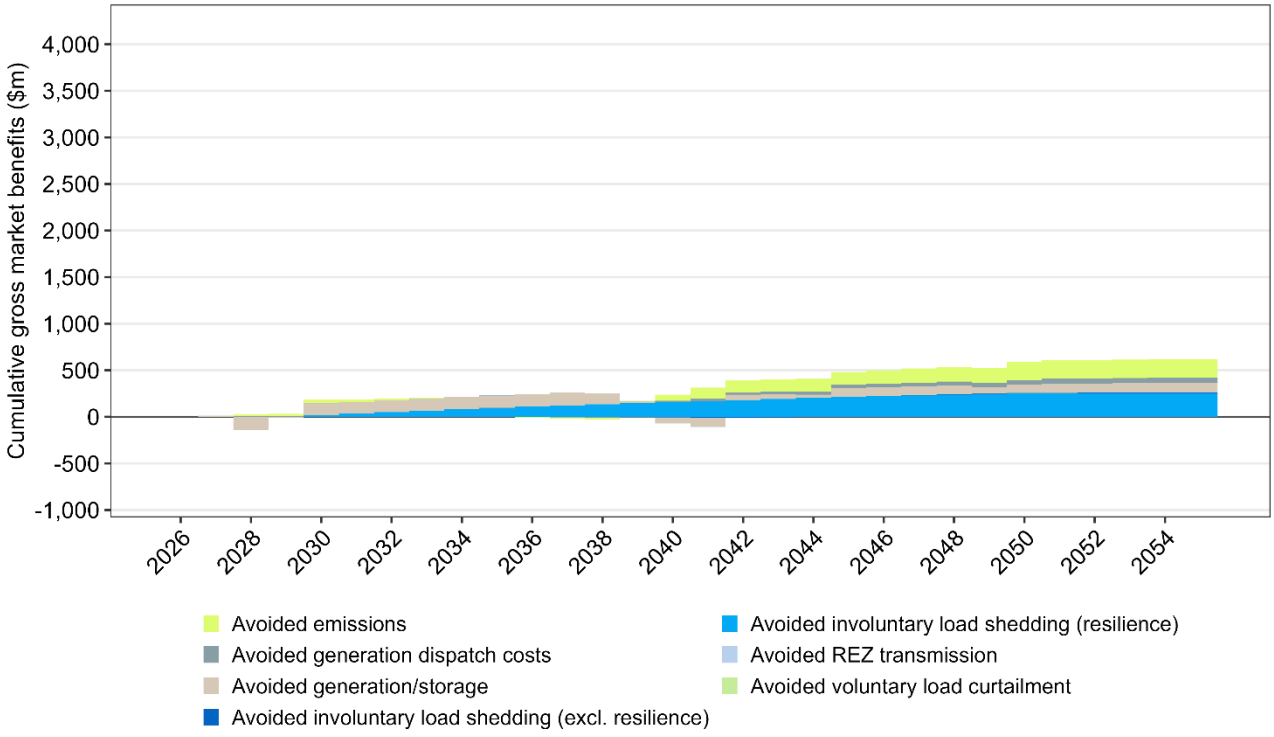


Figure 28 below presents the estimated cumulative expected gross benefits for Option S2 for each year of the assessment period under the Slower Growth scenario.

Figure 28: Breakdown of cumulative gross benefits for Option S2 under the Slower Growth scenario



The key findings from the wholesale market modelling assessment of Option S2 under this scenario are:

- Avoided emissions costs and avoided/deferred generation capital costs are the primary sources of benefit, providing approximately $194 million and $109 million in gross market benefits, in present value terms, respectively.

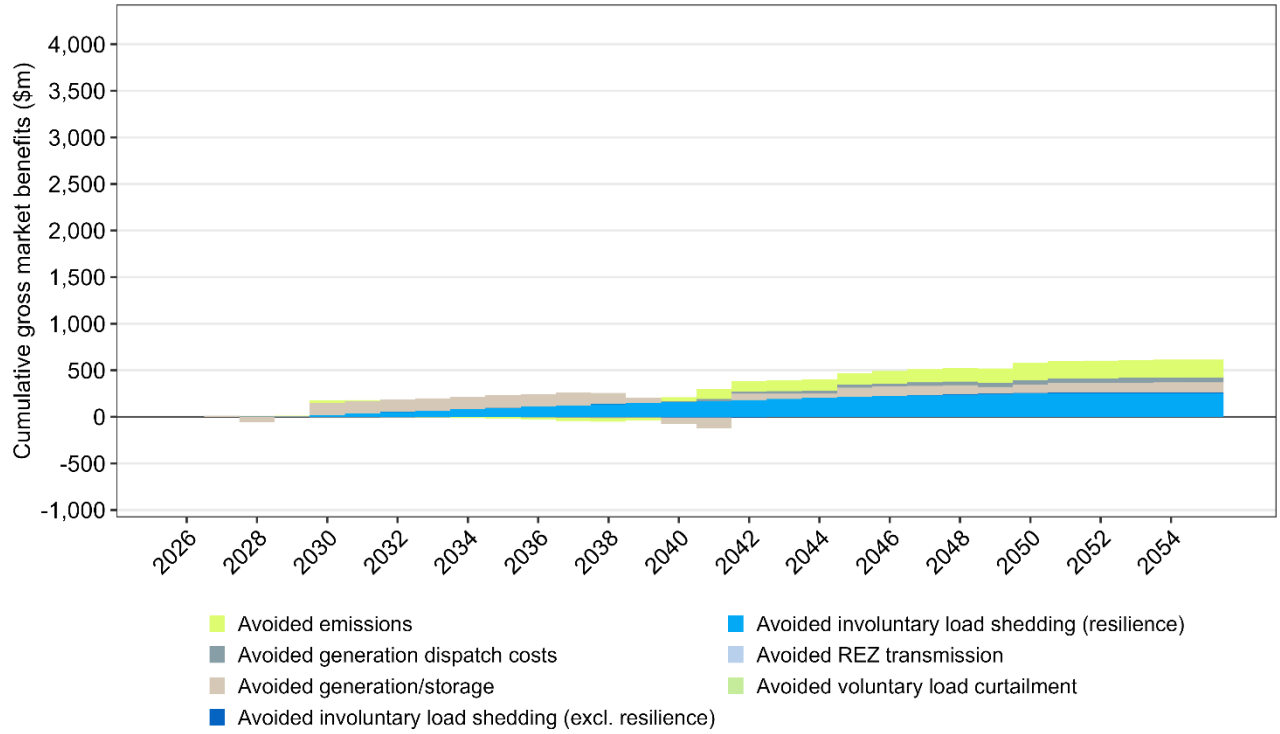
- Avoided/deferred generation and storage capital costs are considerably smaller in magnitude than under the other scenarios.
    - Savings arise from avoided alternative renewable generation in South East SA, consistent with the pattern observed under the other scenarios,
- From 2040 onwards, and similar to the Accelerated Transition scenario (albeit to a much lesser degree), benefits increasingly arise from avoided generation dispatch costs and avoided emissions.
    - These reflect the avoidance of gas generation capacity that would otherwise need to be constructed near Adelaide to meet South Australian demand in the absence of Option S2, with the emissions from that avoided gas generation consequently avoided.
    - Compared to the Accelerated Transition scenario, these emissions cost savings occur slightly later and are smaller in magnitude, consistent with the more gradual demand growth trajectory under this scenario.

As outlined in section 7.1, the network resilience benefits estimated by KPMG outside of the wholesale market modelling exercise are approximately $254 million for Option S2, in present value terms.[132]

Figure 29 below presents the estimated cumulative expected gross benefits for the combined Option S2 and Option N1 for each year of the assessment period under the Slower Growth scenario. While all combined options are found to have negative net market benefits at this point in time, we have presented the breakdown of the estimated market benefits of this combined option to show the incremental benefit arising from the northern option when the southern section is also upgraded.

[132] As outlined in section 6.4, a proportionate assumption has been made for the PADR analysis that all options going to the new site at Bolivar/Dry Creek involve these benefits (and that they are the same in all three ISP scenarios).

Figure 29: Breakdown of cumulative gross benefits for Option S2 combined with Option N1 under the Slower Growth scenario

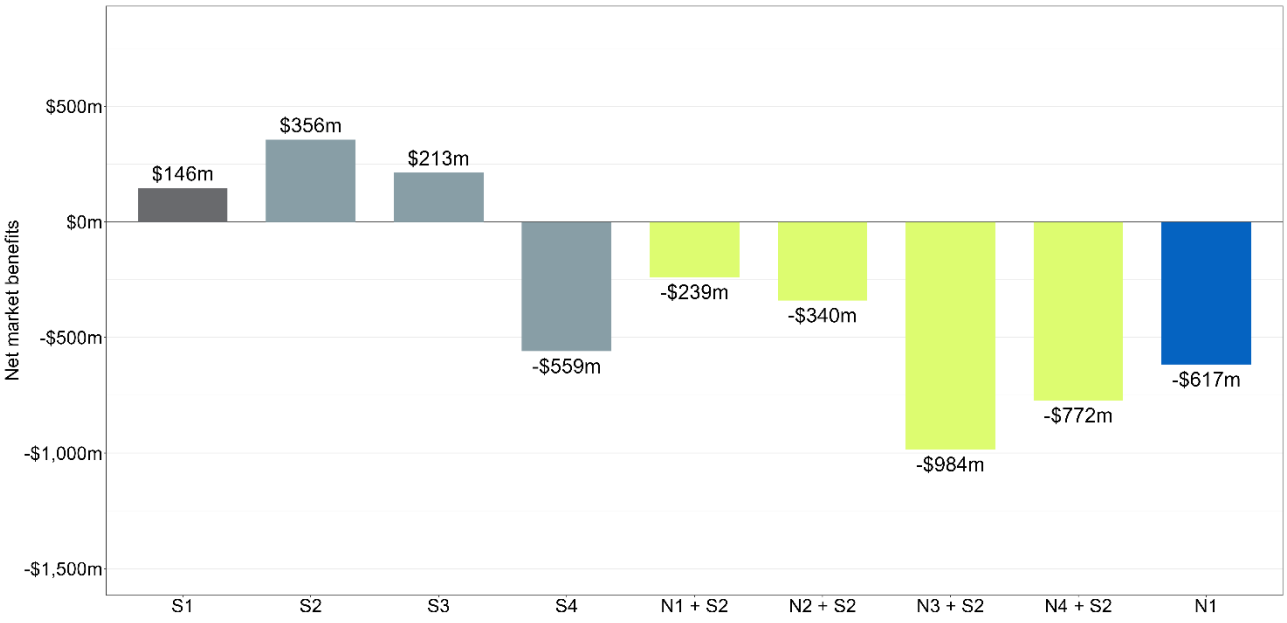


The modelling for the combined Option S2 + N1 shows that the addition of Option N1 contributes no additional gross market benefits, over and above those arising from Option S2 alone.

7.4 Weighted results

Adopting the weights AEMO specifies in the draft 2026 ISP, Option S2 is the top-ranked credible option and is found to have estimated net benefits of approximately $356 million.

Figure 30: Net market benefits on a scenario-weighted basis



While Option S1 is also found to have positive net market benefits, this option is no longer considered likely (for the reasons outlined in section 4.1) and ranks behind Option S2 (and Option S3).

As outlined above, we do not consider that the weight assigned to the Slower Growth scenario to be appropriate based on current connection interest from LILs in South Australia. We have therefore included a sensitivity that relaxes this assumption (the results of this are discussed in the next section).

7.5 Sensitivity analysis

In addition to the scenario analysis outlined above, we have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing.

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

- a zero per cent weighting applied to the Slower Growth scenario;
- higher assumed demand forecasts to align more closely with the connection interest ElectraNet is currently facing from LILs, as well as investigations into different assumed locations for LILs and the removal of the solar constraint;
- the higher estimated network resilience benefits estimated by KPMG;
- changes in option capex cost assumptions; and
- changes in the assumed discount rates.

These sensitivity tests are discussed in the sections below.

7.5.1 The weight applied to the Slower Growth scenario

While Option S2 is found to deliver marginal net market benefits under the Slower Growth scenario, we consider that the benefit is understated due to the demand forecasts used in that scenario not including any LILs. As outlined above, this runs counter to what we are currently seeing from these types of parties wishing to connect to our network. Our recent submission to the draft 2026 ISP stated that the Slower Growth scenario should not be a feature in the assessment of the current nor future ISPs given it is too conservative for planning purposes.[133]

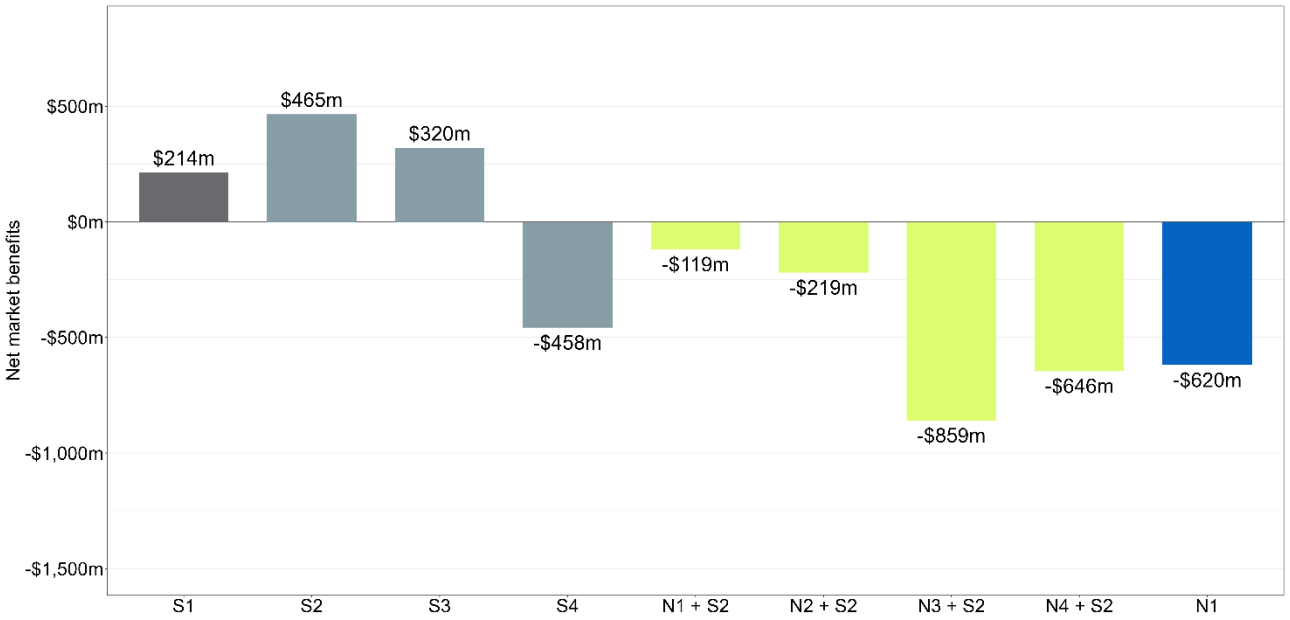
We have therefore investigated a sensitivity that gives the Slower Growth scenario a zero per cent weighting (with the other two scenario weights increased in proportion to their draft 2026 ISP weights).

Under these assumptions, the estimated weighted net benefits of Option S2 increase by 31 per cent (from $356 million to $465 million, in present value terms). In addition, Option S3 is still found to deliver positive net market benefits (of approximately $320 million).

Figure 31 presents the estimated net benefits for each option under this sensitivity test.

[133] ElectraNet, *Draft 2026 ISP Submission*, 13 February 2026, p.8

Figure 31: Sensitivity – Estimated net market benefits without the Slower Growth scenario



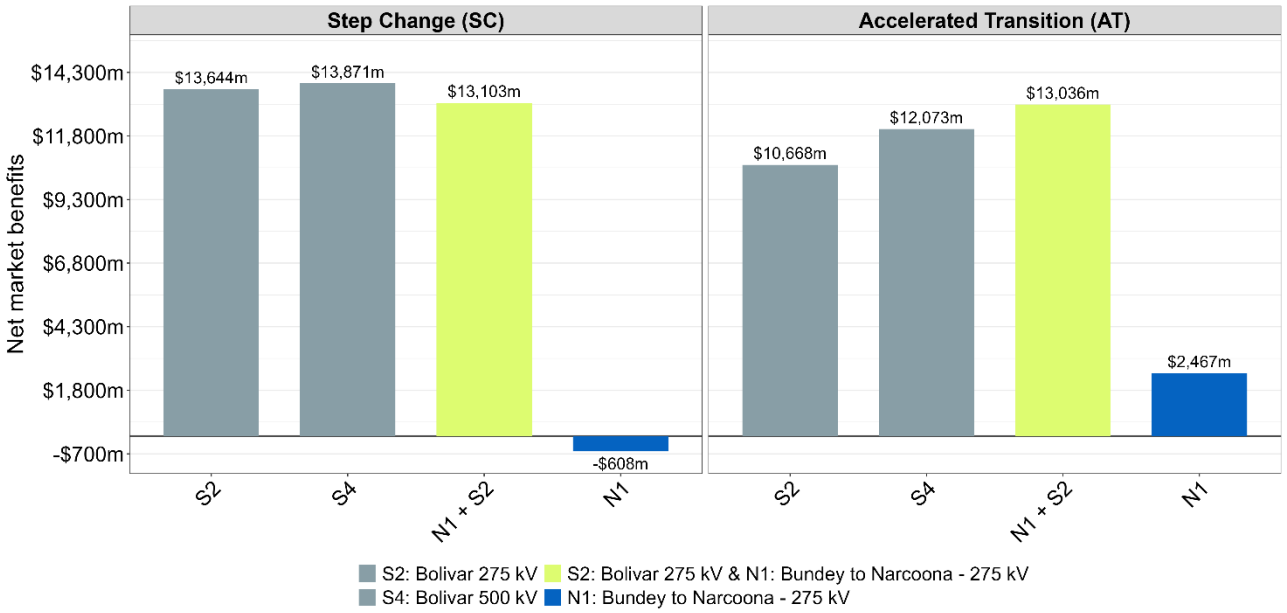
7.5.2 Higher assumed demand forecasts

While the 2025 ESOO demand forecast used in the Step Change and Accelerated Transition scenarios include some LILs, we consider that there is significantly more potential load from LILs in South Australia. For example, ElectraNet is currently engaging with 38 individual large industrial customers exploring direct connections, and these customers are planning more than 65 individual projects (i.e., many customers are seeking connections across multiple developments), with potential interest of around 2,500 MW of additional load by 2035, that could reach 5,500 MW if other less probable LILs were to connect.

We have therefore investigated a sensitivity that increases the LIL uptake in the Step Change and Accelerated Transition scenarios to align more with our expectations regarding these loads. Specifically, we have assumed there is an additional 1,814 MW of flat load added to Central SA and 1,695 MW to Northern SA, with commissioning dates ranging from FY2030, to FY2035.

Figure 32 presents the estimated net benefits under this sensitivity test.

Figure 32: Sensitivity – Net market benefits with a higher LIL uptake



Under these assumptions:

- the estimated net benefits of all options (except for Option N1 under Step Change)[134] increase significantly compared to the core results presented above – e.g., Option S2 increases from $363 million to $13.6 billion under the Step Change scenario;
- a larger capacity southern option is preferred over Option S2 – as shown by Option S4 having greater estimated net benefits than Option S2;[135] and
- the addition of a northern option is expected to be net beneficial under the Accelerated Transition scenario.

The substantial increase in net benefits is driven primarily by additional avoided fuel costs and avoided emissions costs, which reflects the substantially greater volume of gas generation that would otherwise need to be constructed and dispatched near Adelaide to meet the higher load (and the associated emissions from that generation). These benefits are partially offset by higher generation and storage investment costs, reflecting the additional renewable and storage capacity required to serve the larger load base even with NTx in place.

The finding that the net market benefits increase more, relative to the core results, for the southern options under the Step Change scenario than the Accelerated Transition scenario is

[134] The estimated net benefits of Option N1 under the Step Change high demand sensitivity are subject to the ongoing modelling considerations of the northern options discussed in section 7.1.

[135] At this stage, we have taken a proportionate approach to including options in this sensitivity and we have not included Option S3 in the analysis. It is possible that Option S3 may also be preferred over Option S2, and this may be investigated further in the PACR.

driven by the interaction between demand in each scenario and the economics of running of gas generation more versus building new renewable energy.[136]

The incremental gross benefits of combining a northern solution with Option S2 are materially larger than under the core results as a result of the higher LIL demand assumed in the Mid North region creating congestion on the northern constraint. Option S2 alone does not resolve this northern congestion, whereas the addition of a northern connection directly relieves it, enabling the higher demand to be served at lower cost. Under the Accelerated Transition, the combined Option N1 + S2 is found to be the top-ranked option due to these benefits.

However, the incremental northern benefit is conditional on the assumed build limit for solar generation in the S5 REZ. Where no binding limit is placed on this solar, the model resolves the northern congestion by building additional generation within northern South Australia, meaning the constraint is relieved internally without requiring a northern transmission connection. In that case, the incremental benefit of the northern options does not materialise, as the north-south flow path becomes less relevant to the dispatch outcome. When Accelerated Transition high demand sensitivity is run without the solar cap assumed, the combined Option N1 + S2 is no longer found to be the top-ranked option.

As part of the 2026 ISP process, we will therefore be exploring with AEMO both the appropriate amount and location for new assumed LILs, as well as the appropriate 'penalty cost' assumptions for developing new solar generation.

The box below provides additional detail on why the location of new LILs is considered important for the estimated benefits of NTx.

Market modelling investigations highlight the importance of where new load is assumed to locate

Investigations undertaken as part of the wholesale market modelling undertaken for this PADR finds that the location of LILs matters significantly when it comes to the estimated market benefits.

Specifically, if we allocate 20 per cent of forecast loads for the northern SA region to the central SA region (i.e., keeping the total forecast loads across both regions unchanged), we find that the net benefits for Option S2 under the core Accelerated Transition scenario increase significantly from $640 million to $1.61 billion, in present value terms.

This illustrates the importance of where new LIL demand is assumed to locate, and explains the significant increase between the high demand sensitivities above the core results (particularly the core Accelerated Transition results).

In addition, we note that, in the 2024 ISP, AEMO recommended that ElectraNet explore the case for augmentation to support industrial loads given government policy. AEMO undertook a sensitivity analysis as part of that ISP that assumed additional load in the Mid North region and

[136] Specifically, with the same additional demand, the Step Change scenario results in a higher benefit for the southern options than the Accelerated Transition scenario. This is primarily driven by the more gas dispatch in Adelaide that would be avoided with an NTx southern option in the Step Change scenario, as compared to the Accelerated Transition scenario.
Namely, with substantially higher demand under the Accelerated Transition scenario, more renewable and storage generation capacity investments would be made across regions outside of the Mid North region absent NTx, and the value in avoiding these investments with lower-cost renewables in the Mid North region, following NTx, is less than the value of avoiding fuel and emission costs from dispatching gas in the Step Change scenario.

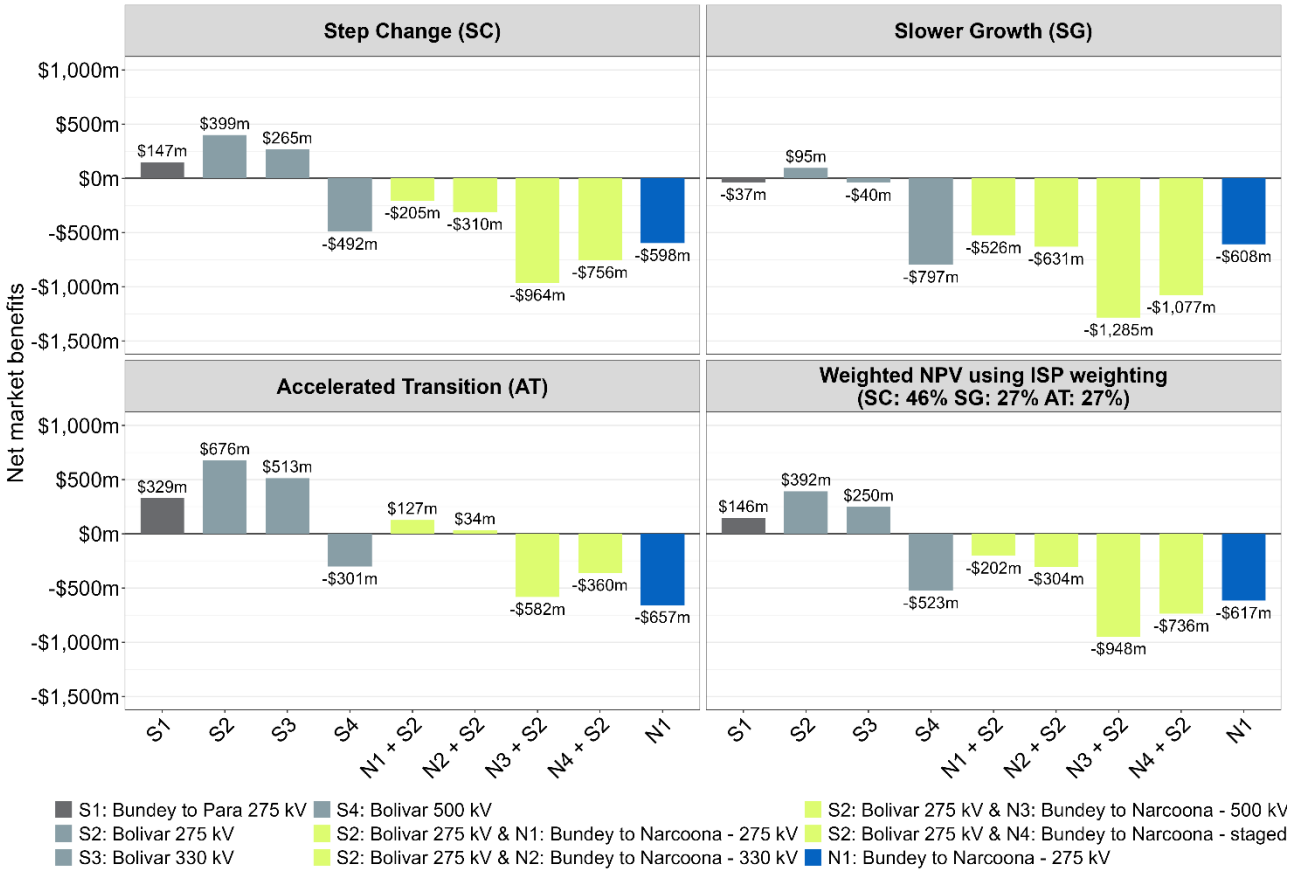
found that potential network capacity may be required if load is connected.[137] While it is not clear that a sensitivity of this type will be included in the 2026 ISP, we consider this type of analysis important to understand how the potential for additional load growth may impact the current investment decision.

7.5.3 Higher estimated network resilience benefits

As outlined in section 6.4, while KPMG have estimated the network resilience benefits for two separate cases, we have applied their 'moderate climate change scenario' estimate in the core PADR assessment.

This sensitivity applies their 'high climate change scenario', which results in greater estimated network resilience benefits. It finds that none of the conclusions of the core analysis are affected.

Figure 33: Sensitivity – Net market benefits with higher estimated network resilience benefits



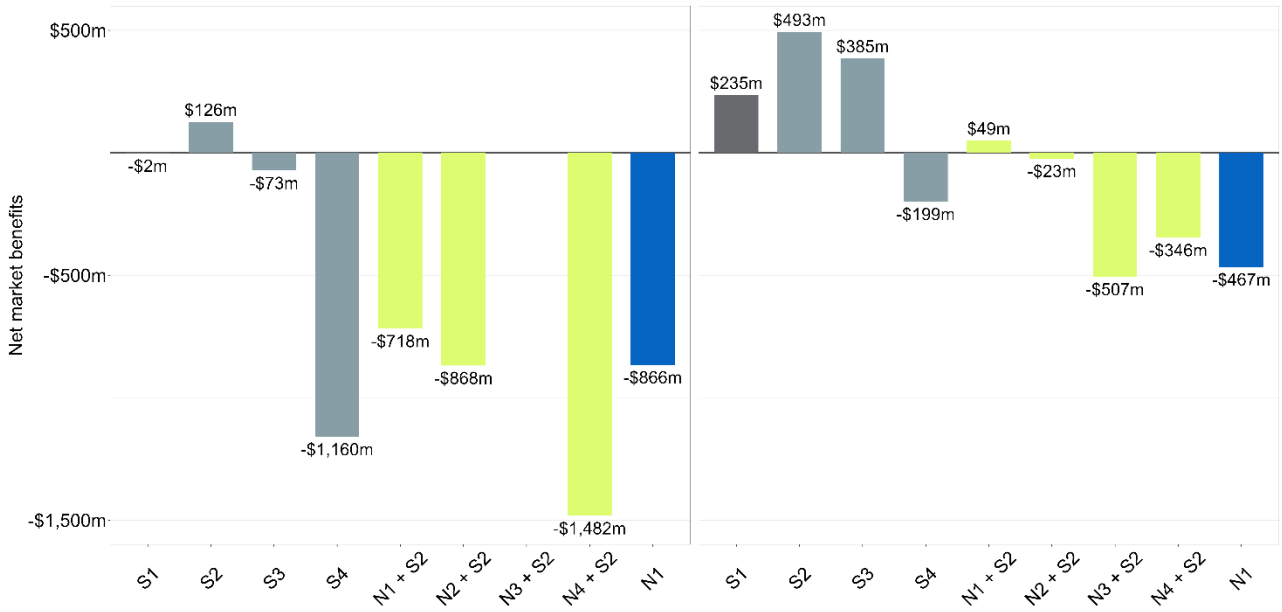
[137] AEMO, *Appendix 5. Network Investments*, June 2024, p. 41.

7.5.4 Estimated capital costs

As outlined in section 6.1, ElectraNet has prepared capital cost estimates reflecting the AACE cost estimate classification system 'Class 4' for the options in this PADR.[138] The Class 4 estimates are of an expected accuracy of +50%/-30%.

Figure 34 presents the estimated net benefits for each option under 30% lower and 50% higher assumed capital costs.

Figure 34: Sensitivity – Estimated net market benefits with 50% higher (LHS) and 30% lower (RHS) capital costs



Extending this sensitivity finds that the central estimates of network capital costs would need to increase by around 77 per cent for Option S2 to have negative expected net benefits on a weighted basis. However, this rises to 100 per cent if the Slower Growth scenario is given a zero per cent weighting (with the other two scenario weights increased in proportion to their draft 2026 ISP weights), i.e. using the results in section 7.5.1 above.

Each of the above capital cost sensitivities also implicitly varies the assumed level of annual operating costs (since it is assumed to be 1 per cent of the underlying capital costs).

7.5.5 Commercial discount rate

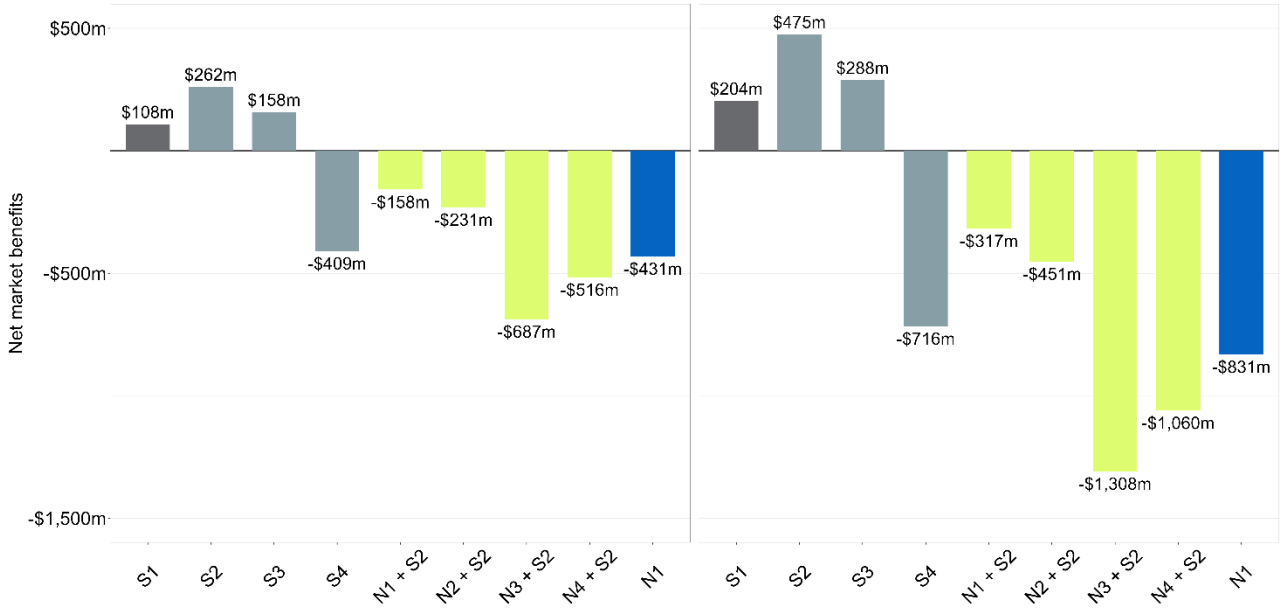
The robustness of the estimated net market benefits to variations in the assumed commercial discount rate has been tested using:

[138] The one exception to this is for Option S4, which has been estimated at a Class 5 level of estimate (as outlined in section 6.1). While the capital costs for Option 4 are Class 5 estimates, we have only varied them by the accuracy range of the Class 4 estimates (i.e., +50%/-30%) in order to present this sensitivity in a simple manner. We do not consider this material as Option S4 is not realistically expected to have net market benefits greater than the preferred option (Option S2).

- a lower bound discount rate of 4.68 per cent;[139] and
- an upper bound discount rate of 10 per cent.[140]

Figure 35 below shows the results under both these assumed discount rates.

Figure 35: Sensitivity – Estimated net market benefits with higher (LHS) and lower (RHS) discount rates



We find that the results are completely robust to the assumed commercial discount rate. That is, there is no realistic discount rate that would make Option S2 have negative expected net benefits on a weighted basis under these revised weightings. We therefore do not consider there to be a realistic re-opening trigger for the commercial discount rate.

[139] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM (Basslink) as of the date of this analysis, see: AER, Feb 2026, Basslink - Determination 2026–30 – Final decision – PTRM.

[140] 10 per cent is the upper bound in the latest 2025 IASR.

8 Conclusion

The PADR assessment finds that Option S2 – a new high capacity 275 kV transmission line between Bundey and a new site (around Bolivar/Dry Creek[141]) – has the greatest expected net market benefits of the credible options assessed. Option S2 also delivers positive net market benefits in each of the three 2026 ISP scenarios.

Using the draft 2026 ISP scenario weights, Option S2 is expected to deliver approximately $356 million of net benefits over the assessment period. If the Slower Growth scenario is given a zero per cent weighting, reflecting the strong interest we are seeing from LILs (and the fact that the Slower Growth scenario includes no LIL over the assessment period), the expected net market benefits increase substantially to $465 million.

While Option S1, the draft 2026 ISP candidate option going to Para instead of Bolivar/Dry Creek, is also found to deliver positive net benefits, we no longer consider it a likely option given the elevated bushfire risk that comes with connecting new lines at that location and, the need to quarantine the existing spare bays at Para for future expansion. While Option S1 has been included in the quantitative assessment in this PADR, it is also found to have significantly lower expected net benefits than Option S2 overall and we therefore do not propose considering this option further.

Option S2 is included in the 2025 AEMO Electricity Network Options Report and is a southern solution developed following further planning by ElectraNet after the 2024 ISP.[142]

Option S2 is considered the preferred option at this draft stage of the RIT-T, and involves the following scope of works:

- a 275 kV double-circuit line from Bundey to a location close to Bolivar/Dry Creek (twin conductor Olive or similar);
- 2x new 275 kV line-connected reactors at Bundey;
- new 275 kV substation at a location close to Bolivar/Dry Creek;
- 2x new 275 kV line-connected reactors at Bolivar/Dry Creek;
- connecting the new substation to existing metropolitan 275 kV network;
- full disconnection of the existing 132 kV lines Waterloo-Templers and Roseworthy-Para;
- two new 132 kV single-circuit line from Templers West to Templers and from Roseworthy to Templers West;
- additional 160 MVA, 275/132 kV transformer at Templers West; and
- replacement of 275/132 kV transformer at Robertstown with a 250 MVA unit

The nominal rating of the new transmission line would be around 2,000 MW and it would allow for an additional 1600 MW of transfer capacity from the Mid North REZ to Adelaide.

[141] The final name for the site would be finalized once its final location is determined.
[142] Following recent consultation with the community, ElectraNet is currently considering corridor options south of Bundey and expects to report on its findings as part of the PACR (as well as our ongoing stakeholder consultation).

The wholesale market modelling undertaken shows that the draft preferred option is expected to provide net market benefits through avoiding/deferring substantial generation capital and dispatch costs as well as avoiding emission costs. These sources of benefits are driven by the upgrade facilitating more efficient investment and operation in the NEM than would occur otherwise, which can be expected to put downwards pressure on electricity prices.

The current estimated capital cost of Option S2 is $1,406.4 million, and all works are expected to take two years to complete (commencing commissioning in 2029/30).

While Option S2 is found to deliver marginally positive net market benefits under the Slower Growth scenario, we consider that this is due to the demand forecasts adopted by AEMO in that scenario not including any LILs. This runs counter to what we are currently seeing from these types of parties wishing to connect to our network.[143]

We have therefore investigated a sensitivity that gives the Slower Growth scenario a zero per cent weighting.[144] Under this assumption, the estimated net benefits of Option S2 increase substantially, by 31 per cent (from $356 million to $465 million, in present value terms).

Further, the PADR sensitivity analysis finds, while the preferred option not to be sensitive to the assumed capital costs and commercial discount rate, the amount/location of new LIL demand matters for the southern options, and may justify a higher-capacity upgrade.

ElectraNet notes that the addition of a northern component of NTx is not found to provide additional net benefits at this stage. The exception to this is under the high demand sensitivity for the Accelerated Transition scenario (assuming a constraint on new solar generation). We have therefore included a re-opening trigger to cater for these circumstances.

Further, based on preliminary network modelling, ElectraNet considers that a northern upgrade may allow for additional market benefits from:

- allowing intra-regional transmission investment elsewhere in our network to meet demand from LILs to be avoided; and
- lower connection costs for mines in the Mid North region of South Australia.

Together, these would provide additional benefits for these upgrades. We intend to assess these potential benefits further ahead of the PACR.

Overall, this RIT-T has been drafted in parallel with AEMO's development of the 2026 ISP. The market modelling in this PADR will be updated ahead of the PACR in order to align with the 2026 ISP. ElectraNet notes that this may have an impact on the outcome of the RIT-T assessment.

[143] For example, ElectraNet is currently engaging with 38 individual large industrial customers exploring direct connections to our network, and these customers are planning more than 65 individual projects, with potential interest of more than 2,500 MW of additional load by 2035.

[144] Our recent submission to the draft 2026 ISP also stated that the Slower Growth scenario should not be a feature in the assessment of the current nor future ISPs given it is too conservative for planning purposes. See: ElectraNet, *Draft 2026 ISP Submission*, 13 February 2026, p.8.

8.1 Proposed re-opening triggers

Under the Rules relating to a Material Change in Circumstance (MCC), we are required to set out in the PADR (for consultation and confirmation in the PACR), re-opening triggers for this RIT-T.

Consistent with these requirements and drawing on the results of the sensitivity testing in this PADR, we have considered the impact of changes in key underlying assumptions to identify reopening triggers. Specifically, we consider that the following are expected to form re-opening triggers for this RIT-T:

- real total capital cost increases of more than 77 per cent, which is the amount beyond which the threshold test currently demonstrates that the preferred option will have negative net market benefits; and
- additional new LILs assumed in Northern South Australia (as well as a higher assumed penalty for developing new solar generation in this region), which we currently expect could justify the inclusion of a northern NTx augmentation in addition to a southern one.

To be clear, should either of these events occur, we would update our analysis to identify whether the preferred option in this RIT-T has changed or is no longer expected to provide positive net market benefits, and would propose a course of action to the AER.

We intend to continue to liaise with AEMO on the size and location of LILs in South Australia as part of the 2026 ISP process, as well as the appropriate solar penalty to assume. This may enable the second re-opening trigger above to be further refined in the PACR.

In addition, ElectraNet has assumed that there will be a new substation established close to Davenport and that the existing Davenport to Cultana 275 kV circuits will be duplicated in the base case for this RIT-T assessment (i.e., consistent with the conclusion of the Eyre Peninsula Upgrade RIT-T). If this is not the case, then there will need to be a rescoping of the northern solutions assessed under this RIT-T, and the expected market benefits of all NTx upgrade options (i.e., southern and northern) will need to be reassessed. ElectraNet intends to investigate this further in the PACR and expects that it may form an additional re-opening trigger for this RIT-T.

We note that any change in the ODP between the draft and the final 2026 ISP will be reflected in the PACR, and so will not constitute an MCC.

We intend to investigate further in the PACR the impact of there being insufficient load on the Eyre Peninsula to justify establishing a new site close to Davenport and duplicating the Davenport to Cultana 275 kV circuits. The outcome of this process may be an additional re-opening trigger for if this situation arises.

Appendix A Compliance Tables

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

Table 14: Compliance checklist of PADR with NER

Rules clause	Summary of requirements	Relevant section(s)
5.16A.4(d)	**A RIT-T proponent must prepare a PADR, which must include:**	–
	(1) include the matters required by the CBA Guidelines;	Table 15
	(2) adopt the identified need set out in the ISP (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary)	Section 2
	(3) describe each credible option assessed	Section 4
	(4) include a quantification of the costs, including a breakdown of operating and capital expenditure for each credible option;	Section 4
	(5) assess market benefits with and without each credible option and provide accompanying explanatory statements regarding the results;	Section 6
	(6) if the RIT-T proponent has varied the ISP parameters, provide demonstrable reasons in accordance with 5.15A.3(b)(7)(iv);[145]	Section 2 & Section 5.1
	(7) identify the proposed preferred option that the RIT-T proponent proposes to adopt	Section 8
	(8) for the proposed preferred option identified under subparagraph (7), the RIT-T proponent must provide: (a) details of the technical characteristics; and (b) the estimated construction timetable and commissioning date.	Section 8
	(9) if each of the following apply to the RIT-T project: (a) the estimated capital cost of the proposed preferred option is greater than $100 million (as varied in accordance with a cost threshold determination);[146] and (b) AEMO is not the sole RIT-T proponent, include the RIT reopening triggers applying to the RIT-T project;	Section 8
	(10) if applicable, set out the costs of early works incurred but not included under clause 5.16A.7(c).	Section 6.1

[145] 5.15A.3(b)(7)(iv) details that the RIT-T proponent must adopt the most recent ISP parameters. Where the RIT-T proponent varies, omits or adds an ISP parameter, it must specify which parameter has been changed and provide clear reasons why the change is necessary

[146] The current threshold determination is $103 million. See: https://www.aer.gov.au/industry/registers/resources/reviews/2024-cost-thresholds-review-regulatory-investment-test, accessed on 18 July 2025.

The table below outlines a separate compliance checklist demonstrating compliance with the binding guidance in the latest AER CBA guidelines (i.e., those included in Table 15 of that document).

Table 15: Compliance checklist of PADR with AER CBA Guidelines

Binding element	Provision	Classification	Relevant section(s)	Section of guidelines
Complying with the CBA guidelines				2.1
Compliance reporting				2.1.2
1	RIT-T proponents are required to provide the AER with a compliance report when applying the RIT-T to an actionable ISP project, which must be submitted no later than 20 business days after the publication of the PACR.	Requirement	Appendix A	
2	In its compliance reports, RIT-T proponents are required to identify where they: • have complied with applicable requirements • have had regard to applicable considerations (including the reasons for the weight they have attached to each consideration) • have resolved key issues raised by the AER through the issues register	Requirement	Appendix A	
3	RIT-T proponents are required to identify breaches of the CBA guidelines, if any, in their compliance reports and provide an explanation for the breach.	Requirement	Appendix A. ElectraNet considers there are no breaches of the CBA Guidelines.	
4	If a compliance report contains confidential information, RIT-T proponents are required to provide another non- confidential version of the report in a form suitable for publication.	Requirement	This compliance report does not contain confidential information	
Interaction and alignment with the RIT-T				3.5
Feedback loop				3.5.3
5	RIT-T proponents are required to inform the AER within one business day of the outcome of a feedback loop assessment in the event the proponent has elected to use the concurrent pathway and AEMO has made a decision not to provide written confirmation	Requirement	NA	
6	If AEMO has extended the time for making a decision on a feedback loop request, RIT-T proponents are required to notify the AER of that extension within one business day of receiving notice of extension from AEMO.	Requirement	NA	

Binding element	Provision	Classification	Relevant section(s)	Section of guidelines
Operation and application of the RIT-T				4.3
Credible options				4.3.1
7	When a RIT-T proponent is considering whether to include new credible options that AEMO did not consider in the ISP, it must have regard to the guidance in section 4.3.1 of the CBA guidelines on what constitutes a credible option when justifying its decision. When identifying new credible options, the RIT-T proponent must consider all options it could reasonably classify as credible options, taking into account factors that the RIT-T proponent reasonably considers it should take into account. In considering what it should take into account, the RIT-T proponent must have regard to the following: • if the identified need in the ISP entails meeting a service standard, the degree of flexibility offered by that service standard • the advantages of constructing credible options with option value • the benefits of constructing new credible options to meet the identified need in the ISP over broadly similar timeframes to the ISP candidate option	Consideration	Section 4	
8	RIT-T proponents must consider social licence issues in the identification of credible options	Consideration	Section 4.5	
Selecting the base case				4.3.2
9	The base case is required to be where the RIT-T proponent does not implement a credible option to meet the identified need, but rather continues its business as usual activities, including for where reliability corrective action is driving the identified need.	Requirement	Section 6	

Binding element	Provision	Classification	Relevant section(s)	Section of guidelines
	Selecting inputs			4.3.3
10	*'Demonstrable reasons' for departing from ISP parameters are required to be limited to where there has been a material change that AEMO would, but is yet to reflect in, a subsequent IASR, ISP or an ISP update. For example, this might include a material change in circumstances, such as where the AER has published updated VCR values that AEMO is yet to incorporate in the IASR. Where a material change is not a change in circumstances or facts (for example, a change in the RIT-T proponent's understanding or assessment of the facts, rather than a change in the facts themselves), the RIT-T proponent might choose to attain written confirmation of the change from AEMO.*	Requirement	Section 2 & Section 5.1	
	Valuing costs			4.3.4
11	If the modelling period is shorter than the life of the credible option, the RIT-T proponent is required to incorporate the operating and maintenance costs (if any) for the remaining years of the credible option into the terminal value.	Requirement	NA – an annualised cost approach has been taken (as opposed to using terminal values)	
12	When valuing the costs of compliance, there may be cases where a RIT-T proponent can lawfully pay a financial amount rather than undertake some other action for compliance. In such cases, the RIT-T proponent must consider whether the financial amount is smaller than the costs of undertaking some other action before determining whether it should treat the financial amount as part of that credible option's costs.	Consideration	NA	
	Market benefit classes			4.3.5
13	RIT-T proponents are required to apply classes of market benefits consistently across all credible options.	Requirement	Section 6.2	
	Methodology for valuing market benefits			4.3.6
14	For any RIT-T application where AEMO has not specified which scenario/s or weightings to apply, the RIT-T proponent must consider the AER's guidance on estimating probability-based weightings as set out in the previous RIT-T application guidelines that applied to all RIT-T projects.	Consideration	NA – weightings have been set out in the ISP	

Binding element	Provision	Classification	Relevant section(s)	Section of guidelines

15	Where calculating the benefit from changes in Australia's greenhouse gas emissions, a RIT-T proponent is required to:
	• include the following emissions scopes, unless the change relative to the base case can be demonstrated to be immaterial to the RIT outcome
	  ○ direct emissions from generation
	  ○ direct emissions other than from generation, e.g. sulphur hexafluoride.
	• estimate the change in annual emissions (once identified in accordance with this Guideline) between the base case and the credible option, and multiplying this change by the annual VER to arrive at the annual benefit from changes in Australia's greenhouse gas emissions.
		Requirement	See external market modelling report.	

	Sensitivity testing			4.3.8
16	RIT-T proponents must perform sensitivity testing on all credible options by varying one or multiple inputs/assumptions. In considering whether or how to perform sensitivity testing, the RIT-T proponent must have regard to any relevant risks identified in stakeholder submissions, and whether sensitivity testing would build on the analysis already undertaken in the ISP and be proportionate and relevant to the RIT-T assessment.	Requirement	Section 7.5	

Binding element	Provision	Classification	Relevant section(s)	Section of guidelines
	Suitable modelling periods			**4.3.9**
17	The RIT-T proponent must consider using the ISP modelling period (also known as the planning horizon) of 20+ years as the default when assessing credible options to meet identified needs arising out of the ISP. If the expected profile of the market benefits and costs of the ISP candidate option are longer than the modelling period used in the ISP, the RIT-T proponent must consider whether it might be valuable to adopt a longer modelling period, whilst also considering the need for alignment with the ISP. For relatively incremental ISP candidate options, the RIT-T proponent must consider whether a shorter period would reduce the computational burden without compromising the quality of the CBA or undermining alignment with the ISP.	Requirement	Section 6.7	
18	Where the modelling period is shorter than the expected life of a credible option, the RIT-T proponent is required to include any relevant and material terminal values in its discounted cash flow analysis. The RIT-T proponent is required to explain and justify the assumptions underpinning its approach to calculating the terminal value, which represents the credible option's expected cost and benefits over the remaining years of its economic life.	Requirement	NA – an annualised cost approach has been taken (as opposed to using terminal values)	

Binding element	Provision	Classification	Relevant section(s)	Section of guidelines
Concessional finance agreements				4.3.11
19	The RIT-T proponent is required to only include the part of the benefit of a concessional finance agreement that is passed on to consumers in the RIT-T assessment. For a proposed concessional finance agreement to be included in the RIT stage of a project, a proponent is required to have, and provide, reasons and evidence to explain why they are confident the agreement is likely to be executed. The proponent is required to also provide details about the benefit to be shared with consumers, including about how the sharing of that benefit will occur, along with supporting evidence and information to substantiate these matters. If a proponent seeks to include an unexecuted concessional finance agreement in the RIT T, proponent is required to undertake sensitivity testing for the scenario the agreement doesn't eventuate.	Requirement	NA	
Staged projects under the ISP framework				4.4
20	For the purposes of clause 5.16A.5(b) of the NER, the relevant cost is the cost for the particular stage.[147] However, AEMO also must have regard to the full cost of the project in providing its written confirmation, under clause 5.16A.5(b) of the NER, that the status of the actionable ISP project remains unchanged.	Consideration	NA	
Consumer and non-network engagement				4.5.1
21	The RIT-T proponent is required to use reasonable endeavours to ensure they meet 'community engagement expectations' as defined in the NER.	Requirement	Section 4.5	
22	The RIT-T proponent is required to publish a stakeholder engagement plan as soon as practicable before publication of the PADR. The RIT-T proponent is required to report against this engagement plan in each RIT-T report.	Requirement		
23	The RIT-T proponent must consider publishing an update to their engagement plan if the approach to engagement has changed.	Consideration	NA	

[147] This cost is also the relevant cost for NER, clause 5.16A.5(d).

Binding element	Provision	Classification	Relevant section(s)	Section of guidelines
24	The RIT-T proponent is required to engage with stakeholders who are reasonably expected to affected by the project's development.	Requirement	Section 4.5	
25	The RIT-T proponent must consider describing in each RIT-T report how it has engaged with consumers, as well as other stakeholders; and sought to address any relevant concerns identified as a result of that engagement. The RIT-T proponent must consider undertaking early engagement with consumers, non-network businesses and other key stakeholders to the extent that doing so complements rather than duplicates or hinders AEMO's engagement work in developing the ISP. The RIT-T proponent also must have regard to how it can adopt best practice consumer engagement in line with our 'consumer engagement guideline for network service providers'.	Consideration		
26	The RIT-T proponent is required to provide transparent, user-friendly data to stakeholders, to the extent this protects commercially sensitive information and is not already provided by the ISP.	Requirement	Section 4.5 and the additional material released alongside this PADR.	
27	In providing transparent, user-friendly data to stakeholders, the RIT-T proponent must have regard to how it can present information in line with stakeholder preferences.	Consideration		
Project assessment draft report				**4.5.2**
28	The Draft Report is required to include, if applicable: • Demonstrable reasons for adopting different modelling techniques to what AEMO used in the ISP. • An explanation as to why any non-network options proposed in response to new actionable ISP projects in the final ISP are not credible options.	Requirement	• Section 5.1 • Section 3	
Project assessment conclusions report				**4.5.3**
29	When publishing the Conclusions Report, RIT-T proponents are required to: • Publish, in addition to a summary of submissions, any submissions received in response to the Draft Report, unless marked confidential. • Date the Conclusions Report to inform potential disputing parties of the timeframes for lodging a dispute notice with the AER.	Requirement	NA	

Binding element	Provision	Classification	Relevant section(s)	Section of guidelines
30	If a RIT-T proponent receives any confidential submissions on its Draft Report, it must consider working with submitting parties to make a redacted or non- confidential version public.	Consideration	NA	

The table below outlines a compliance checklist demonstrating compliance with the additional RIT-T requirements not included in the list of binding elements in the CBA guidelines (i.e., those outside of Table 15 in the guidelines).

Table 16: Additional RIT-T requirements not included in the list of binding elements in the CBA guidelines

Section in the CBA guidelines	Summary of the requirements	Relevant section(s)
	Treatment of early works costs	
4.3.4	In conducting a RIT-T for an actionable ISP project, the proponent must include only: • the outstanding costs not yet incurred (at the time of the PADR or PACR, as the case may be) for each credible option, and • costs already incurred, if the assets acquired through incurring those costs can be sold or utilised to support other projects. Where the activities funded via an early works contingent project application have not yet been fully completed, the RIT-T proponent should specify the amount that has been incurred so far and the remaining amount expect, or forecast, to be incurred. For amounts of early works costs that have already been incurred, the RIT-T proponent should specify the amounts that the proponent considers relate to assets that can be sold or utilised to support other projects, and the facts and reasons on which its view is based.	Section 6.1

Section in the CBA guidelines	Summary of the requirements	Relevant section(s)
Cost estimation accuracy		

4.3.4A	Where the estimated capital costs of the preferred option exceed $100 million (as varied in accordance with a cost threshold determination as contemplated by clause 5.16.4(k)(10)(i) of the NER), a RIT-T proponent must, in a RIT-T application:
	• outline the process it has applied, or intends to apply, to ensure that the estimated costs are accurate to the extent practicable having regard to the purpose of that stage of the RIT-T
	• for all credible options (including the preferred option), either
	  ○ apply the cost estimate classification system published by the Association for the Advancement of Cost Engineering (AACE), or
	  ○ if it does not apply the AACE cost estimate classification system, identify the alternative cost estimation system or cost estimation arrangements it intends to apply, and provide reasons to explain why applying that alternative system or arrangements is more appropriate or suitable than applying the AACE cost estimate classification system in producing an accurate cost estimate.
		Section 6.1

Additional cost estimation information and contingency allowances		
4.3.4A	For each credible option, a RIT-T proponent must specify, to the extent practicable and in a manner which is fit for purpose for that stage of the RIT-T: • all key inputs and assumptions adopted in deriving the cost estimate • a breakdown of the main components of the cost estimate • the methodologies and processes applied in deriving the cost estimate (e.g. market testing, unit costs from recent projects, and engineering-based cost estimates) • the reasons in support of the key inputs and assumptions adopted and methodologies and processes applied • the level of any contingency allowance that have been included in the cost estimate, and the reasons for that level of contingency allowance.	Section 4.3 and Section 6.1

Section in the CBA guidelines	Summary of the requirements	Relevant section(s)
Additional cost estimation information and contingency allowances		
4.3.4A	Contingency allowances are often included in cost estimates to allow a RIT-T proponent to take into account uncertainty in the costs of a credible option. If a contingency allowance is included in a cost estimate for a credible option, the RIT-T proponent must explain: • the reasons and basis for the contingency allowance, including the particular costs that the contingency allowance may relate to, and • how the level or quantum of the contingency allowance was determined	Section 6.1

Appendix B Definitions

All laws, regulations, orders, licences, codes, determinations and other regulatory instruments (other than the Rules) which apply to Registered Participants from time to time, including those applicable in each participating jurisdiction as listed below, to the extent that they regulate or contain terms and conditions relating to access to a network, connection to a network, the provision of network services, network service price or augmentation of a network.

Definitions	
Applicable regulatory instruments	A comprehensive list of applicable regulatory instruments is provided in the Rules.
AEMO	Australian Energy Market Operator
Base case	A situation in which no option is implemented by, or on behalf of the transmission network service provider.
Commercially feasible	An option is commercially feasible if a reasonable and objective operator, acting rationally in accordance with the requirements of the RIT-T, would be prepared to develop or provide the option in isolation of any substitute options. This is taken to be synonymous with 'economically feasible'.
Costs	Costs are the present value of the direct costs of a credible option
Credible option	A credible option is an option (or group of options) that: address the identified need; is (or are) commercially and technically feasible; and can be implemented in sufficient time to meet the identified need.
Economically feasible	An option is likely to be economically feasible where its estimated costs are comparable to other credible options which address the identified need. One important exception to this Rules guidance applies where it is expected that a credible option or options are likely to deliver materially higher market benefits. In these circumstances the option may be "economically feasible" despite the higher expected cost. This is taken to be synonymous with 'commercially feasible'
Identified need	The reason why the Transmission Network Service Provider proposes that a particular investment be undertaken in respect of its transmission network.

electranet