SA ENERGY TRANSFORMATION RIT-T

Project Assessment Draft Report

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ElectraNet

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Revision Record

Date	Version	Description	Author	Checked By	Approved By
29/6/18	1.0	First Issue	Brad Harrison	Hugo Klingenberg	Rainer Korte
10/7/18	1.1	Updated Figure 6, submissions due date and minor corrections	Brad Harrison	Hugo Klingenberg	Rainer Korte

Executive Summary

ElectraNet has investigated interconnector and network support options aimed at reducing the cost of providing secure and reliable electricity to South Australia in the near term, while facilitating the longer-term transition of the energy sector across the National Energy Market (NEM) to low emission energy sources.

We are applying the Regulatory Investment Test for Transmission (RIT-T)[1] to this identified need. This Project Assessment Draft Report (PADR) has been prepared as the second formal step in the South Australia Energy Transformation (SAET) RIT-T process.[2]

Our investigation has been undertaken in consultation with, and with the support of, the Australian Energy Market Operator (AEMO) as the national planning body and Jurisdictional Planning Bodies AEMO (Victoria), Powerlink (Queensland) and TransGrid (New South Wales).

A new high capacity interconnector between South Australia and New South Wales would deliver substantial economic benefits as soon as it can be built

Our RIT-T assessment shows that of all options considered a new 330 kV interconnector between mid-north South Australia and Wagga Wagga in New South Wales, via Buronga, is expected to deliver the highest net market benefits. This finding is robust across a wide range of future scenarios and sensitivity tests.

The preferred option[3] is estimated to deliver net market benefits of around $1 billion over 21 years (in present value terms) [4], including wholesale market fuel cost savings of around $100 million per annum putting downward pressure on wholesale electricity prices with flow on benefits to customer pricing. Independent modelling by ACIL Allen estimates an overall reduction in the average annual residential customer bill of up to about $30 in South Australia and $20 in New South Wales.

The new interconnector is estimated to cost $1.5 billion across both South Australia and New South Wales and could be delivered by 2022 to 2024.

Our work has been closely coordinated with the development of AEMO's Integrated System Plan (ISP)

A key development since the publication of the Project Specification Consultation Report (PSCR) in November 2016 has been the development by AEMO of an Integrated System Plan (ISP) that provides a 'roadmap' for the transition of the energy sector, in response to a recommendation of the Finkel review.[5] Finkel highlighted that additional interconnection within the NEM was likely to form a key feature of the transition, and would help to unlock low emission generation Renewable Energy Zones (REZs).

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1 The Regulatory Investment Test for Transmission (RIT-T) is the economic cost benefit test that is overseen by the Australian Energy Regulator (AER) and applies to all major network investments in the NEM.

2 ElectraNet obtained approval from the AER to extend the timeframe for publishing the PADR to 30 June 2018.

3 The preferred option is defined as the option that maximises net market benefits under the RIT-T framework.

4 Broader benefits to the wider economic are additional to and beyond the scope of this RIT-T assessment, which is required to focus on the direct benefits to consumers and producers of electricity.

5 Finkel, A., *Independent Review into the Future Security of the National Electricity Market – Blueprint for the Future, June 2017*

ElectraNet considers it essential that the outcomes of the RIT-T are fully coordinated with the ISP to deliver outcomes that are best for the NEM as a whole, and in the interests of electricity customers. We have been working closely with AEMO to achieve the required coordination.

A new interconnector between South Australia and New South Wales has been confirmed by AEMO in the ISP[6] as an important element of the 'roadmap' for the NEM and as one of its immediate priorities that would deliver positive net market benefits as soon as it can be built.

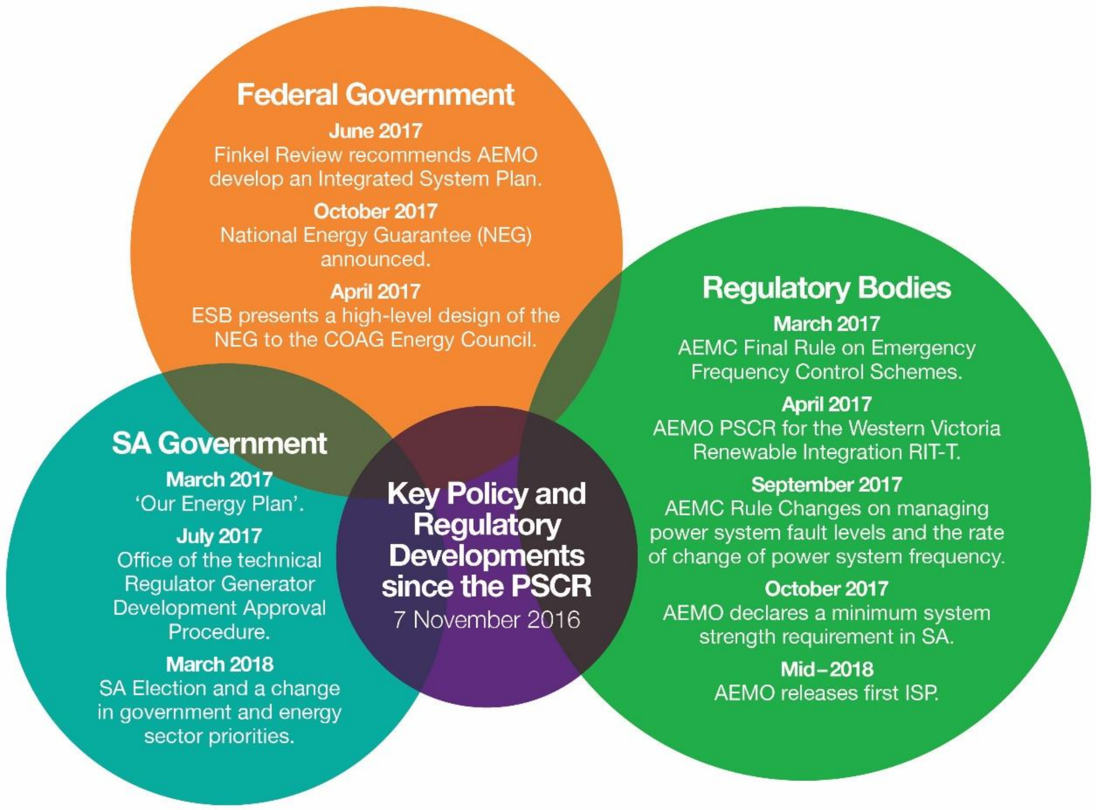
This RIT-T is the process through which a more detailed economic cost-benefit assessment is undertaken to identify the most appropriate option that delivers the greatest net market benefits.

In assessing options under this RIT-T, we have reflected the assumptions adopted by AEMO in the ISP in all material respects. We have also taken into account the complementary investments identified by AEMO as part of the ISP, in particular the investments being considered by AEMO's Western Victoria Renewable Integration RIT-T and the identification of priority REZ zones in the Riverland and Murray River areas of South Australia and New South Wales.

This RIT-T assessment has been undertaken in an environment of significant regulatory and policy changes, which have been taken into account

In addition to the development of the ISP, there have been many other important changes to regulations and policies since publication of the PSCR, affecting both the NEM as a whole, and South Australia specifically, as highlighted in Figure E.1.

Figure E.1 – Key policy and regulatory developments since release of the PSCR



6 AEMO, Integrated System Plan, June 2018. AEMO refers to this new interconnector as 'Riverlink' in the ISP.

These changes have had a material impact on both the identified need for the investment being considered in this RIT-T, as well as the assessment of the costs and benefits of different options to meet this need.

The identified need for this RIT-T, as stated in the PSCR, is to deliver net market benefits and support energy market transition through:

- lowering dispatch costs, initially in South Australia, through increasing access to supply options across regions.
- facilitating the transition to a lower carbon emissions future and the adoption of new technologies, through improving access to high quality renewable resources across regions.
- enhancing security of electricity supply, including management of inertia, frequency response and system strength in South Australia.

Given the substantive and at times uncertain nature of recent policy changes, we have delayed publication of this PADR to ensure that the changes are properly understood and reflected in our analysis and to ensure our work is fully coordinated with national planning processes.

We are now releasing the draft results of our assessment, which take into account the above changes, in conjunction with publication by AEMO of the inaugural ISP.

ElectraNet has investigated four broad credible options

We have investigated variants of four credible options to address the identified need, comprising both a local South Australian 'non-interconnector' option (comprising both network and non-network components) as well as options involving new interconnectors to each of the three neighbouring NEM states, as shown in Figure E.2.

We engaged engineering consultants Entura to provide technical insight into how network support technologies could assist, particularly in relation to providing system security, and to develop a least cost, standalone 'non-interconnector' option to be considered in the RIT-T assessment. Submissions to the PSCR from network support proponents helped shape the non-network components of this option.

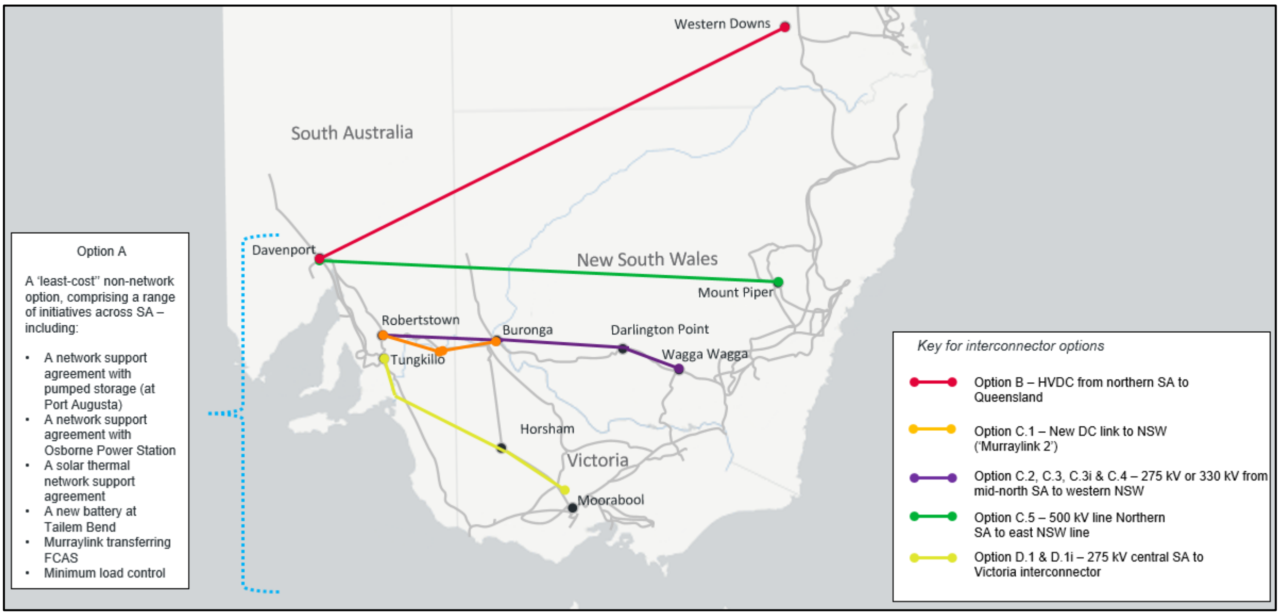
For the interconnector options, both HVAC[7] and HVDC[8] options have been considered, with line lengths varying from 350 km to 1,450 km. These options have additional capacity varying from 300 MW to 1,000 MW, with indicative costs of $0.8 billion to $2.9 billion. Potential energisation could occur from 2022 to 2024.

The broad routes of the interconnector options remain the same as set out in the PSCR, with additional analysis having enabled the options to be better defined.

[7] High voltage alternating current

[8] High voltage direct current

Figure E.2 – Overview of the options (and variants) assessed



The preferred option delivers positive net benefits across all reasonable future scenarios

Future uncertainty is captured under the RIT-T framework through the use of scenarios, which reflect different assumptions about future market development, as well other factors that are expected to affect the relative market benefits of the options being considered. The key variables affecting the current RIT-T assessment include long-term gas prices, electricity demand, emissions reduction policy targets (at both state and Federal levels), and any change in the rate of change of frequency (RoCoF) security settings for South Australia.

Three scenarios have been considered, which are intended to cover a wide range of possible futures. These are summarised at a high-level in Table E.1. These scenarios are generally aligned with the ISP's slow change, neutral and fast change scenarios, although a wider range of future gas prices has been assessed in the RIT-T analysis, as well as a potential future change in security of supply settings and increasing load in South Australia.

Table E.1 – Summary of future scenarios considered

High Scenario	Central Scenario	Low Scenario
Intended to represent the upper end of the potential range of realistic net benefits from the options	Reflects the best estimate of the evolution of the market going forward	Intended to represent the lower end of the potential range of realistic net benefits associated with the various options

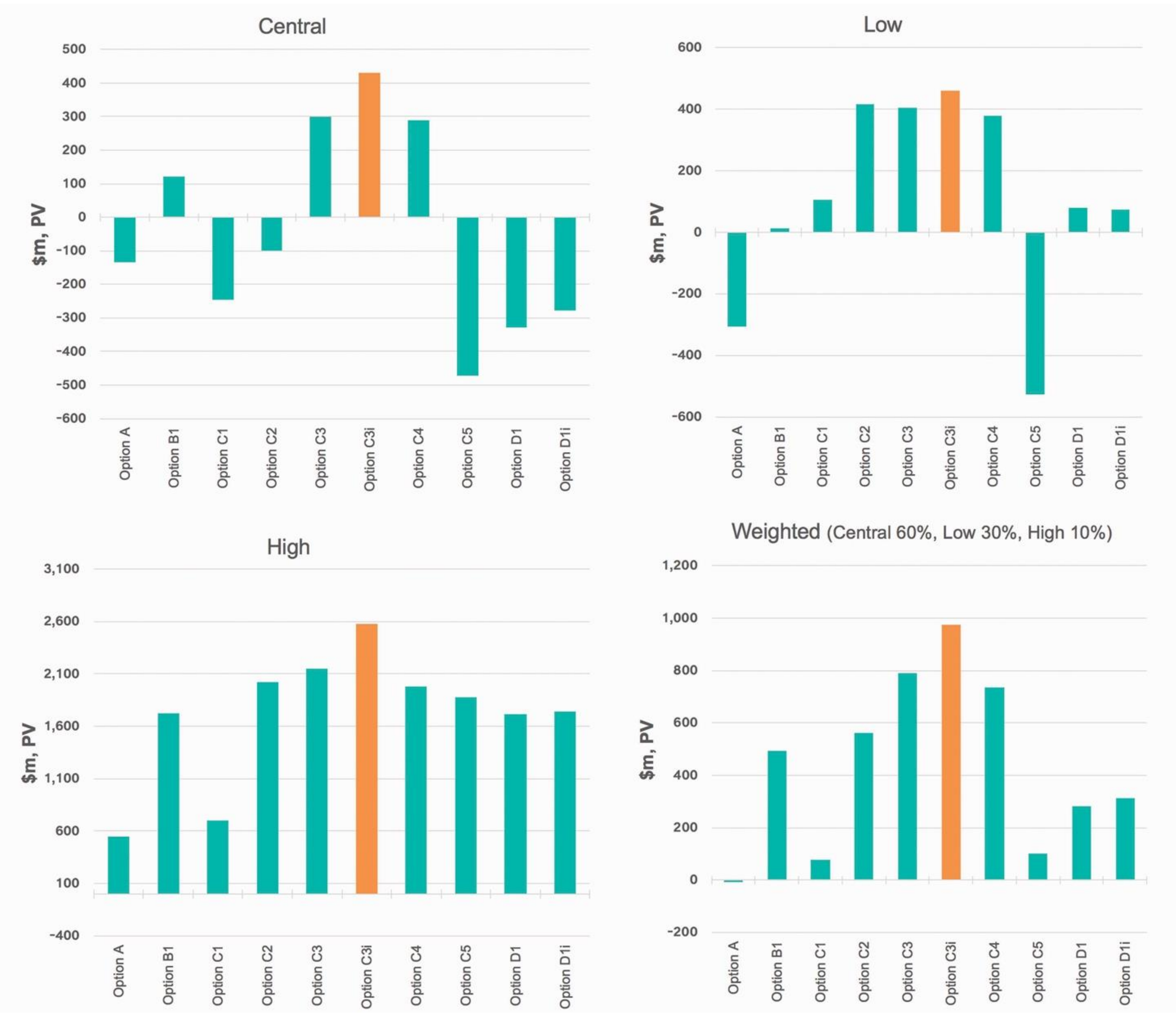
We have also tested the robustness of the assessment to a wide range of sensitivities, including the outcomes of the concurrent Western Victoria RIT-T, the assumed timing of gas generator retirements in South Australia, differences in assumed future mining load developments in South Australia and the estimated costs of the various options.

The results of the RIT-T assessment show that AC interconnection options between mid-North South Australia and central and western New South Wales at either 275 kV or 330 kV are expected to have a material positive net market benefit across all future scenarios -– with particularly large net market benefits estimated under the high scenario (see Figure E.3).

Overall, new interconnection at 330 kV between mid-north South Australia and Wagga Wagga in New South Wales via Buronga (Option C.3i) is expected to deliver the highest net market benefit in all three scenarios, providing a 'no regrets' solution. This option has therefore been identified as the preferred option in the RIT-T assessment.

Option C.3i has net benefits that are materially higher than the next highest ranked option in each scenario, and so the results of the RIT-T are not dependent on particular scenario weightings.

Figure E.3 – Estimated net market benefits for each scenario



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The relatively higher costs of 500 kV interconnection, as well as a new DC link between South Australia and New South Wales ('Murraylink 2'), which was proposed in response to the PSCR, are not outweighed by materially higher market benefits, except in the high scenario. These options result in negative net market benefits in the other scenarios.

New interconnection between South Australia and Victoria was found to have only marginal net benefits or negative net benefits, except in the high scenario. Similarly, new interconnection with Queensland only provides materially positive net benefits in the high scenario.

The non-interconnector option is generally estimated to deliver negative net market benefits, except in the high scenario – this option only contributes to enhancing system security outcomes and does not materially lower dispatch costs, or facilitate the transition to lower carbon emissions compared to the interconnector options, with the consequence that the benefits do not in general outweigh the expected cost.

Market benefits of new interconnection are driven in the near term by lowering generation dispatch costs in South Australia

A key component of the overall benefits for all new interconnector options across all scenarios is the ability to utilise lower cost generation on the east coast of the NEM to supply South Australia in the near term, reducing reliance on expensive gas-fired generation in South Australia. This would result in the wholesale price of electricity reducing in South Australia as soon as interconnection is established. It will also result in a reduction in gas consumption for power generation in South Australia, freeing up gas for other uses, although the flow-on benefit of this is not formally captured in the RIT-T.

We have assessed the sensitivity of our findings to underlying gas price assumptions, given the importance of reduced gas generation in driving the market benefit assessment. We have tested a value of $7.40/GJ (Adelaide) in the low scenario, based on advice from independent analysts EnergyQuest[9] on a realistic future low gas price. This gas price is lower than the $8.00/GJ assumed by AEMO in its ISP 'slow change' scenario, although it is above the more extreme $5.89/GJ tested by AEMO as a sensitivity in the ISP.[10] We do not consider such a low price to be a plausible outcome.

We find that that there remain positive net market benefits for a new South Australia to New South Wales 330 kV interconnector, for all future gas prices even down to the extreme $5.89/GJ tested by AEMO.

In the medium to longer term, new interconnection provides diverse low cost renewable generation sources to New South Wales

As the electricity sector transitions, coal generators are expected to retire from the market over the medium to longer term. The retirement of coal generation is expected to be most rapid in New South Wales, with the ISP highlighting that Eraring and Bayswater are expected to retire by 2034 and 2035, leaving Mount Piper as the sole remaining coal fired generator in New South Wales.

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9 EnergyQuest is an Australian-based energy advisory firm, which specialises in independent energy market analysis, including on Australian oil and gas.

10 The $5.89/GJ assumption is reflected in the 'Increased role for gas' scenario in the ISP.

New interconnection between South Australia and New South Wales results in additional market benefits compared to options involving interconnection with other states, arising from the retirement of New South Wales black coal plant.

Our assessment shows that a new interconnector between South Australia and New South Wales allows greater exports from existing and new high quality renewable generation sources in South Australia and from existing South Australian gas generators, that enables supply requirements in New South Wales to be met at a lower cost than if New South Wales was required to draw on other generation sources, including new gas generation, to fill the gap. Any earlier retirement of coal generation in New South Wales would accelerate delivery of these benefits.

New interconnection also provides benefits through enabling greater integration of renewables in the NEM

The interconnection options between South Australia and New South Wales provide a benefit through being able to avoid the intra-regional transmission costs that AEMO estimates in the ISP would otherwise be required to unlock additional renewable generation resources in the Murray River and Riverland REZs. We have used the results of AEMO's ISP modelling of these potential REZs to identify the extent of transmission costs that could be avoided.

Similar 'REZ benefits' do not arise under the interconnection options between South Australia and either Queensland or Victoria, as there are no identified REZ transmission augmentations that are expected to be impacted by these options.

New interconnection further enhances the security of supply for South Australia

Both the interconnector and non-interconnector options contribute to improving system security. These improvements are captured in the RIT-T assessment through alleviating two existing network constraints: the RoCoF constraint on the operation of the existing Heywood interconnector and the cap on non-synchronous generation output in South Australia.

The benefit of relieving these constraints is captured in the cost benefit analysis as part of the fuel cost savings in South Australia, as alleviating these constraints reduces the need to dispatch higher cost gas generation in South Australia.

We are interested to hear feedback on this PADR

ElectraNet welcomes written submissions on the information presented in this PADR. Submissions are due by 24 August 2018.

Submissions should be marked "South Australian Energy Transformation PADR feedback" and emailed to consultation@electranet.com.au.

The next formal stage of this RIT-T involves publication of a Project Assessment Conclusions Report (PACR). We currently anticipate that a PACR will be released by November 2018.

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Glossary of Terms

Term	Description
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
EST	South Australian Energy Security Target
ETC	Electricity Transmission Code
FCAS	Frequency Control Ancillary Services
GSOO	Gas Statement of Opportunities
HVAC	High-Voltage Alternating Current
HVDC	High-Voltage Direct Current
ISP	Integrated System Plan
LRET	Large Scale Renewable Energy Target
NCAS	Network Control Ancillary Services
NEG	National Energy Guarantee
NEM	National Energy Market
NER	National Electricity Rules
NPS	Northern Power Station
NPV	Net Present Value
NSCAS	Network Support and Control Ancillary Services
NTNDP	National Transmission Network Development Plan
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
PTRM	Post Tax Revenue Model
PV	Photovoltaic
QRET	Queensland Renewable Energy Target
RET	Renewable Energy Target
REZs	Renewable Energy Zones
RIT-T	Regulatory Investment Test for Transmission
RoCoF	Rate of Change of Frequency
SACOME	South Australian Chamber of Mines and Energy
SAET	South Australia Energy Transformation
SIPS	System Integrity Protection Scheme
SRAS	System Restart Ancillary Services
TNSP	Transmission Network Service Provider
USE	Unserved Energy
VCR	Value of Customer Reliability
VRET	Victoria Renewable Energy Target
VSC	Voltage Source Converter

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1. Introduction

The South Australia Energy Transformation (SAET) RIT-T is investigating the economic benefits of new interconnector and network support options aimed at reducing the cost of providing secure and reliable electricity, while facilitating the transition of the energy sector to low emission energy sources.

This PADR has been prepared by ElectraNet as the second formal step in the RIT-T process. It follows the Project Specification Consultation Report (PSCR), released on 7 November 2016[11].

Our investigation has been undertaken in consultation with and with the support of the Australian Energy Market Operator (AEMO) as the national planning body and relevant Jurisdictional Planning Bodies AEMO (Victoria), Powerlink (Queensland) and TransGrid (New South Wales).

This report presents the draft findings of the RIT-T assessment, including identifying a new 330 kV interconnector between South Australia and NSW, via Buronga, as the preferred option which is expected to maximise overall net market benefits.

This finding is consistent with AEMO's finding in the ISP that a new interconnector between South Australia and New South Wales is an important element of the 'roadmap' for the NEM and one of its immediate priorities, that would deliver positive net market benefits as soon as it can be built.

This RIT-T is the process through which a more detailed economic cost-benefit assessment is undertaken to decide whether new interconnection with South Australia is developed, and to identify the most appropriate option.

This report summarises submissions to the PSCR, presents the economic modelling of the costs and benefits of the credible options considered, and describes how changes in policy, particularly in relation to managing system security and system strength issues, have been reflected in the analysis.

1.1 Three reports have been released for consultation to-date

The first stage of this RIT-T involved release of the PSCR in November 2016. ElectraNet subsequently issued two additional reports for consultation, in order to provide further information and transparency to stakeholders in relation to this assessment. These additional reports were the:

- Market Modelling Approach and Assumptions Report (published in December 2016); and
- the PSCR Supplementary Information Paper (published in February 2017), which provided further details to facilitate proposals from proponents of network support technologies.

[11] ElectraNet obtained approval from the AER to extend the timeframe for publishing the PADR under the Rules to 30 June 2018.

We received submissions from 35 parties in total in response to these various consultation reports. The submissions addressed topics falling into the following five broad categories:

- submissions commenting on the proposed network options, and/or proposing additional network options;
- proposals or submissions in relation to network support technologies;
- general information or feedback regarding the RIT-T process and approach;
- specific comments on the proposed analysis for this RIT-T; and
- feedback on ElectraNet's proposed market modelling approach.

We thank all those who have engaged with us on this important endeavour thus far. Feedback received has helped refine the identified need and develop a range of credible options for evaluation.

1.2 Recent policy and regulatory developments are reflected in this PADR

The reliability and security of the electricity system in South Australia and across the whole of the National Electricity Market (the NEM) has been a key policy focus of both the market bodies (AEMO and the AEMC) and the state and federal Governments over the past eighteen months. Ensuring the on-going reliability and affordability of electricity supply, as the sector transitions to a low-emissions future and adjusts to the adoption of new technologies, has emerged as a key policy challenge.

In response to these challenges there have been a number of policies introduced by the South Australian Government and, more recently, being progressed at the Federal Government level. AEMO and the AEMC have also progressed several Rule changes and other regulatory changes which have focused on addressing these challenges.

We have updated our consideration of the identified need in the light of the various developments since the publication of the PSCR, and describes in this PADR how the changes in policy, particularly in relation to managing system security and system strength issues, have been reflected in the RIT-T analysis.

As noted above, we have also worked closely with AEMO in order to ensure that this RIT-T assessment and the ISP are appropriately coordinated.

1.3 Role of this report

This report:

- summarises key policy and regulatory developments since the publication of the earlier PSCR;
- describes why ElectraNet is undertaking this analysis (the 'identified need' for the investment);

- summarises the submissions received on the PSCR and the earlier Market Modelling Approach and Assumptions Report, and how these have been addressed in the RIT-T analysis;
- describes the options being assessed under this RIT-T, including the non-interconnector option;
- presents the results of the NPV analysis for each of the credible option assessed;
- identifies that a new 330 kV interconnector between South Australia and NSW, via Buronga, is expected to maximise the net market benefit, and is therefore the preferred option for investment; and
- describes the key drivers of this results, and the assessment that has been undertaken to ensure the robustness of the conclusion.

The next formal stage of this RIT-T involves publication of a PACR. ElectraNet currently anticipates that a PACR will be released by November 2018.

ElectraNet is also releasing supplementary reports alongside this PADR. These supplementary reports are listed in Appendix D. Detailed cost benefit results are also included as a spreadsheet appendix to this report.

1.4 Submissions and next steps

We welcome written submissions on this PADR. Submissions are due by 24 August 2018.

Submissions should be marked "South Australian Energy Transformation PADR feedback" and emailed to consultation@electranet.com.au.

Submissions will be published on the ElectraNet website. If you do not want your submission to be made publicly available, please clearly specify this at the time of lodging your submission.

Further details in relation to this project can be obtained from:

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2. Key developments since the release of the PSCR

Since the publication of the PSCR, there have been many important changes to regulations and policies affecting both the NEM as a whole and South Australia specifically. These developments are summarised in Table 1 below.

These policy and regulatory changes have the largest impact on the treatment of system security, frequency control and system strength within the RIT-T assessment – all of which formed an important component of the identified need set out in the earlier PSCR. They also affect consideration of how the SAET RIT-T interacts with other potential transmission and generation developments across the NEM.

Table 1: Key policy and regulatory developments since release of the PSCR

Date	Description
March 2017	AEMC Final Rule on Emergency Frequency Control Schemes
March 2017	SA Government - Our Energy Plan
April 2017	AEMO PSCR for the Western Victoria Renewable Integration RIT-T
June 2017	Finkel Review recommends AEMO develop an Integrated System Plan (ISP)
July 2017	Office of the Technical Regulator Generator Development Approval Procedure
September 2017	AEMC Rule Changes on managing the rate of change of power system frequency and power system fault levels
October 2017	AEMO declares a minimum system strength requirement in SA
October 2017	National Energy Guarantee announced
March 2018	South Australian election and a change in government
April 2018	ESB presents a high-level design of the NEG to the COAG Energy Council
July 2018	AEMO to release inaugural ISP

A summary of each of these developments is provided in the sections below.

2.1 Development of AEMO Integrated System Plan

A key development since the publication of the PSCR was the outcome of the independent Finkel review, which included a recommendation for AEMO to develop an ISP to provide a 'roadmap' for the transition of the energy sector.

Finkel highlighted that additional interconnection within the NEM was likely to form a key feature of the transition,[12] and would help to unlock low emission generation in Renewable Energy Zones (REZs).

[12] Finkel, A., *Independent Review into the Future Security of the National Electricity Market – Blueprint for the Future, June 2017*, p 121

AEMO has found in its inaugural ISP that a new interconnector between South Australia and the rest of the NEM is expected to form part of the NEM transition path, and to deliver positive market benefits as soon as it can be built. AEMO refers to this potential new interconnector as ‘Riverlink’ in the ISP.

ElectraNet has been actively engaged in the AEMO ISP process. In assessing options under this RIT-T, ElectraNet has reflected all of the assumptions adopted by AEMO in the ISP, where they are material to the outcome of this RIT-T. ElectraNet has also taken into account the complementary investments identified by AEMO in the ISP, in particular the identification of priority REZs in the Riverland and Murray River areas of South Australia and NSW.

2.2 The Western Victoria Renewable Integration RIT-T

In April 2017, AEMO released a PSCR for the Western Victoria Renewable Integration RIT-T. This RIT-T is assessing if network or non-network solutions in the Western Victoria area, to facilitate the connection of additional renewable energy sources, will return positive net market benefits.

ElectraNet has engaged with AEMO to ensure that interactions between the investments being considered in the SAET RIT-T and the Western Victoria Renewable Integration RIT-T are adequately taken into account, and that the outcomes are not affected by differences in the timing of the two RIT-T processes.

ElectraNet has explicitly considered the impact on the SAET RIT-T assessment of different outcomes of the Western Victoria RIT-T, as part of the sensitivities tested in this PADR.

2.3 Managing power system frequency and fault level Rule changes

On 19 September 2017, the AEMC finalised changes to the National Electricity Rules on managing the rate of change of power system frequency and managing power system fault levels. These rule changes were proposed by the South Australian Minister for Mineral Resources and Energy.

The AEMC’s rate of change in system frequency final rule places an obligation on TNSPs to procure minimum levels of inertia or procure other services, such as fast frequency response, to reduce the minimum level of inertia required, to meet any shortfalls identified by AEMO.[13] AEMO is required to calculate the required minimum inertia levels for parts of the network that must be able to operate independently if required.

Similarly, the AEMC’s managing power system fault levels final rule also places an obligation on TNSPs, in this case to procure system strength services to meet any shortfalls identified by AEMO. [14]

In addition, the rule change requires that new generators that connect to the grid must satisfy a ‘do-no-harm’ requirement, meaning that the generator must not have an adverse impact on the ability of the power system to maintain system security.

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[13] AEMC, *Rule Determination – National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017*, 19 September 2017

[14] AEMC, *Rule Determination – National Electricity Amendment (Managing power system fault levels) Rule 2017*, 19 September 2017

In implementing this rule change, AEMO is required to develop a methodology for determining system strength requirements and develop impact assessment guidelines for assessing the potential impact of a generator connection. Interim guidelines were published in November 2017, with the final guidelines required to be published by 1 July 2018.

2.4 AEMO's assessment of system strength in South Australia

In parallel with the AEMC's consideration of the rule change for managing power system fault levels, in September 2017, AEMO published an assessment of system strength in South Australia.[15]

This assessment was undertaken after a Network Support and Control Ancillary Services (NSCAS) gap for system strength in South Australia was identified in the 2016 National Transmission Network Development Plan (NTNDP).

In line with the above AEMC system security rule changes, a fault level shortfall (i.e. a "system strength") gap was subsequently identified by AEMO and ElectraNet is currently responding to this gap with expedited implementation of a synchronous condenser solution that is expected to be in operation by 2020.

This solution is built into the base case for consideration of new interconnector and non-interconnector options in market modelling reported in this PADR. The presence of the synchronous condensers is expected to increase the amount of non-synchronous generation that may be online in South Australia compared with AEMO's earlier analysis, as well as providing around 2,400 MWs of inertia within South Australia that is permanently available.

While the solution will increase the amount of non-synchronous generation that may be online, some limits on non-synchronous generation are still expected. AEMO's most recent assessment is that a cap on non-synchronous generation of 1,870 MW[16] with increments and decrements to this cap depending on the level of export or import respectively over the Heywood interconnector. This constraint has been reflected in the market modelling undertaken by ElectraNet.

2.5 Announcement of 'Our Energy Plan' by the previous SA Government

In March 2017, the then South Australian Government announced its 'Our Energy Plan' set of policies.[17] The plan included a range of initiatives, including:

- the procurement of additional battery storage;
- new powers for the South Australian Government to direct the market in the case of a supply shortfall;
- the construction of a state-owned gas-fired generator in South Australia;

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[15] AEMO, *South Australia System Strength Assessment*, September 2017

[16] This assumes zero flows over the Heywood interconnector and that the quantity of synchronous generation in South Australia exceeds a minimum level known as the synchronous floor.

[17] See http://ourenergyplan.sa.gov.au

- the procurement of other generation using state Government electricity supply contracts;
- the establishment of a South Australian Energy Security Target which required a target level of generation to be met by local dispatchable generators. The then Government subsequently announced in September 2017 that it would delay the implementation of the EST from 2018 until 2020; and
- new incentives for local production of gas.

The then Government proceeded to contract with Neoen for the installation of battery storage at the Hornsdale Wind Farm and with the procurement of a solar thermal plant at Port Augusta via a Generation Project Agreement.[18] The Hornsdale battery has been reflected in the market modelling for this RIT-T, while contracting with the solar thermal plant has been considered as a potential component of the non-interconnector option.

With the change in the South Australian Government in March 2018, it has been announced that the state-owned gas-fired generator will not be pursued. The Government has also made no commitment to pursue the South Australian Energy Security Target, which has therefore been excluded from our analysis.

2.6 The proposed National Energy Guarantee

On 17 October 2017, the Commonwealth Government released its new energy policy, centred on the introduction of a National Energy Guarantee.[19] The policy aims to balance achieving system security and reliability outcomes with emissions reductions for the electricity market through two principal components; a reliability guarantee and an emissions guarantee. The policy would be implemented by creating new obligations on retailers, such that they must contract for electricity to meet their load with a portfolio of generators that satisfies system security, dispatchability and emissions intensity requirements.

The Energy Security Board is charged with developing the design of the NEG, for Ministers' final approval. A high-level design was presented to the COAG Energy Council in April 2018, and further design details were published on 15 June 2018. However, the final details of the National Energy Guarantee remain to be developed, while the design work is proceeding.

Indications from the Commonwealth Government and the Energy Security Board are that the 'emissions' component of the new policy will continue to meet Australia's COP21 Paris emissions reduction commitments. The 'reliability' component of the policy is targeted at providing a safety net mechanism for meeting the NEM reliability standard, which is established by the Reliability Panel, and currently requires that unserved energy (USE) in any region cannot exceed 0.002 per cent of demand per financial year.

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[18] The Generation Project Agreement is similar to a Power Purchase Agreement for renewable energy, except that emphasis is placed on the available capacity of the facility during peak demand periods rather than just the energy that can be delivered in kilowatt-hours.

[19] Energy Security Board, *Energy Security Board (ESB) Advice on a Retailer Reliability, Emissions Guarantee and Affordability*, 13 October 2017

As a consequence, it has not been necessary to undertake any specific additional modelling of the NEG as part of this RIT-T, given that:

- including the NEM reliability standard as a constraint within the market modelling is expected to capture the intended outcomes of the NEG on reliability.[20]
- modelling of different emissions reductions targets across scenarios is expected to capture the intended outcomes of the NEG on emission reduction.

2.7 AEMC Final Rule on Emergency Frequency Control Scheme

On 30 March 2017, the AEMC made a Rule change determination establishing an enhanced framework for emergency frequency control in the NEM, including a new classification of a contingency event ('the protected event'), that in circumstances defined by such an event, will allow power system security to be maintained for events that are not currently managed.

AEMO's inaugural Power System Security Frequency Risk Review Report was published recently[21]. An outage of the Heywood interconnector has been classified by AEMO as a protected event, only during extreme weather conditions. Therefore, the market modelling conducted for the RIT-T has not treated such an outage as a protected event, in the base case and for the non-interconnector option. For interconnector options, the system is designed to manage the loss of either the existing Heywood interconnector or the new interconnector with some response from batteries and load shedding.

ElectraNet has conducted a sensitivity analysis to assess the impact of an outage of the Heywood interconnector being classified by AEMO as a protected event in the future. Any such classification would result in a constraint on the flows over the Heywood interconnector in the base case, with a corresponding increase in the market benefits associated with new interconnector options, as they would relieve this constraint.

2.8 New Generator Development Approval Procedure for South Australia

A new Generator Development Approval Procedure developed by the Office of the Technical Regulator became effective 1 July 2017, and mandates a set of technical requirements generators must meet to ensure power system security.

These requirements have not been explicitly captured in the market modelling at this stage, as there is remaining uncertainty on the precise nature and cost of the investments required. It is expected that these requirements will result in an increase in the 'connection costs' of South Australia generators relative to generators in the rest of the NEM.

However, these costs are not expected to materially impact on the estimated benefits of this RIT-T. ElectraNet will consider the new requirements further in the analysis for the PACR, if it appears that they may become material to the RIT-T outcome.

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20 In the event that the NEG establishes the reliability component to be met within each region, then the specification of this constraint in the modelling would change. The potential impact of this is discussed further in the [separate market modelling report].

21 www.aemo.com.au

3. Benefits of the investment options being considered

The driver for the investments being considered under this RIT-T is to create a net benefit to consumers and producers of electricity and support energy market transition through:

- lowering dispatch costs, initially in South Australia, through increasing access to supply options across regions.
- facilitating the transition to a lower carbon emissions future and the adoption of new technologies through improving access to high quality renewable resources across regions.
- enhancing security of electricity supply, including management of inertia, frequency response and system strength in South Australia.

This 'identified need' for investment remains consistent with that identified in the PSCR, although the development of new policies and responses that directly manage system security means that the importance of this element has reduced.

In particular, the declaration by AEMO on 13 October 2017 of a system strength gap in South Australia is leading to an expedited implementation of a synchronous condenser solution by ElectraNet that is expected to be in operation by 2020. This solution is built into the base case for consideration of interconnector and non-interconnector options in this PADR.

Notwithstanding these developments, there is still scope for the investments being considered in this RIT-T to provide market benefits through further enhancing system security, over and above these requirements.

The drivers for market benefits in each of these three areas are discussed further below.

3.1 Benefits from lower dispatch costs, initially in South Australia

A number of South Australian generators have permanently, or partially, withdrawn from the market in the recent past, including Northern Power Station (NPS) which closed in May 2016. The impact of the substantial investment in new wind and rooftop solar photovoltaic (PV) generation in South Australia has been a contributing factor to this withdrawal.

Gas in the interconnected eastern seaboard markets has also experienced a rapid increase in demand and subsequently price. With the closure of NPS, South Australia has become more reliant on the gas markets for firm electricity supply.

A new interconnector would put downward pressure on dispatch costs in South Australia, as soon as it can be built. Specifically, new interconnector options would enable demand in South Australia to be met through using low cost generating capacity that currently exists on the east coast of the NEM. This would have a substantive impact in reducing the total dispatch costs in South Australia – providing an overall market benefit.

In the longer term, an enhanced ability to export low cost power from South Australia, including renewables, can also provide market benefits by enabling supply in other jurisdictions to be met at a lower overall cost, as existing coal-fired plant retires. This is particularly the case for options involving new interconnection to New South Wales, which is forecast by AEMO to experience the greatest retirement of coal plant in the period from 2030, and which otherwise would rely on higher cost sources of generation to fill the resulting gap in supply.

We note the points raised in several submissions that the current ‘surplus’ low cost generation may not be an enduring feature of the NEM, and that interconnectors ‘move the problem around’ and do not of themselves result in new, low cost generation sources.

However, the market modelling for this RIT-T is being undertaken over a 21 year time horizon and considers different future market development scenarios, which vary in terms of key assumptions such as emissions policies and future gas prices, as well as sensitivities to factors such as future generator retirement dates.

The market benefits identified in this RIT-T assessment are therefore robust to both a range of longer term views, and to different market development paths. Although interconnectors do not ‘create’ new low cost generation sources, by relieving constraints between regions they enable the efficient sharing of generation resources between regions, and can encourage more efficient investment in low cost generation sources, enabling overall demand and system reliability requirements to be met at lowest cost.

While not explicitly captured as a ‘market benefit’ under the RIT-T, it is important to recognise the extent of current price differences between South Australia and the rest of the NEM.

For example, since the announced closure of NPS, spot and futures prices in South Australia have experienced a sharp increase, more than the eastern states have experienced – South Australia electricity base futures prices are around $84/MWh for the next three years, while prices in New South Wales and Victoria range from $66 to $70/MWh over that same time horizon.[22] The effect of this difference in future prices could see South Australian customers pay around $200 million more, per annum, than equivalent customers inter-state.[23]

This increased cost and financial stress faced by electricity users in South Australia has created concerns regarding the impact on vulnerable customers in the state, the competitiveness of industrial businesses within the state and the potential negative flow on impacts of this reduced competitiveness on the South Australian economy and employment. In addition, there is well reported pressure on gas contracts on the east coast of Australia and so any reduced demand for gas for power generation would help relieve this pressure for commercial users of gas.

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22 ASX Energy website, available at: https://www.asxenergy.com.au/, accessed 8 June 2018. Calculated as average Calendar Base Future Prices from 2019 to 2021, inclusive.

23 Calculated as difference between average three year Calendar Base Future Prices of South Australia and NSW multiplied by SA annual energy consumption of 12,700 GWh.

3.2 Benefits attributable to the transition to lower carbon emissions

South Australia has among the most abundant and high quality renewable energy resources in Australia and has seen an unprecedented, and highly publicised, uptake of renewable generation over the last decade, in particular wind and rooftop solar PV installations on residential and commercial properties. Total renewable energy resources in South Australia exceed its combined minimum demand and export capability, putting it at the forefront of renewable power systems across the world.

Australia's COP21[24] commitment to reduce carbon emissions by 26 to 28 per cent below 2005 levels by 2030 has significant implications for the future operation of the NEM. Meeting this commitment, will lead to further replacement of some of Australia's emissions intensive generators with lower emission alternatives, such as renewable energy sources.[25]

The Commonwealth Government's proposed National Energy Guarantee, through the Emissions Guarantee component, is expected to deliver on Australia's COP21 emissions reduction commitments.[26] It proposes to achieve this by placing an obligation on retailers to contract to meet their demand with a portfolio of generation that satisfies emission reduction requirements, to trade their emissions reduction obligations with other parties or to purchase carbon offsets from international markets.

New interconnection with South Australia would allow renewable energy from South Australia to assist the nation in meeting carbon emission and renewable energy targets at lowest long run cost.

New interconnection also has the potential to substitute for the additional intra-regional transmission investment that AEMO is projecting in its ISP would otherwise be required to unlock Renewable Energy Zones.

Within the context of the RIT-T assessment, greater output from renewable generation can be expected to primarily deliver the following classes of market benefit while assisting in meeting national emission reduction commitments:

- further reductions in total dispatch costs, by enabling low cost renewable generation to displace higher cost conventional generation;
- reduced generation investment costs, resulting from more efficient investment and retirement decisions, due to high quality renewables in South Australia, and diversification in generation leading to reduced need for firming capacity.

Several submissions to the PSCR noted that there is a potential trade-off between lowering dispatch costs and lowering the level of emissions. Importantly, the modelling for this RIT-T incorporates an overall constraint on emission levels in all but the low scenario (in which emissions fall below the target levels without the need for a constraint).

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[24] The 2015 United Nations Climate Change Conference (also known as 'COP 21' or 'CMP 11') was held in Paris, France, from 30 November to 12 December 2015

[25] COAG Energy Council, *Review of the Regulatory Investment Test for Transmission*, Consultation Paper, Energy Project Team, 30 September 2016, p. 13

[26] Energy Security Board, *Energy Security Board (ESB) Advice on a Retailer Reliability, Emissions Guarantee and Affordability*, 13 October 2017

In addition, we are reporting as part of the results of our analysis the implied change in carbon emission quantities associated with each option. Whilst not a requirement under the RIT-T, we consider that this information is helpful in addressing the concerns raised.

3.3 Benefits from enhancing security of supply in South Australia

Additional obligations and investments made in South Australia since the 2016 state-wide power outage means that the options considered in this RIT-T are no longer a primary source of system security benefit for South Australia. These developments include the commissioning of a System Integrity Protection Scheme (as recommended by AEMO following the September 2016 system black event in South Australia), and the commitment to deliver synchronous condensers to meet the system strength gap declared by AEMO, as discussed earlier.

However, both interconnector and non-interconnector options are able to contribute to meeting system security standards in South Australia at lower cost than would otherwise be the case, through their impact in alleviating two constraints:

- the RoCoF constraint on the operation of the existing Heywood interconnector, which limits the capacity of Heywood in certain circumstances; and
- the cap on the level of non-synchronous generation that may be on-line in South Australia to ensure adequate system strength.

This impact is reflected in the cost benefit analysis as a component of the fuel cost savings in South Australia, as alleviating the constraints reduces the dispatch of higher gas generators in South Australia.

4. Submissions to the PSCR and additional consultation documents

ElectraNet published the PSCR in November 2016 and subsequently published two additional reports for consultation in relation to this assessment.

These additional reports were the Market Modelling Approach and Assumptions Report published in December 2016 and the PSCR Supplementary Information Paper published in February 2017, which provided further details to facilitate proposals from proponents of network support technologies.

We received submissions from 35 parties in response to its PSCR, which addressed topics falling into the following five broad categories:

- submissions on network options;
- proposals or submissions in relation to non-network options;
- general information or feedback regarding the RIT-T process;
- specific comments on RIT-T analysis; and
- feedback on the market modelling approach.

Table 2 summarises the broad categorisation of stakeholders that submitted to the PSCR.

Table 2 – Summary of submissions to earlier consultation papers

Submissions from	No.	Submission topics	No.
Jurisdictional planning bodies	3	Network options	5
Market participants	14	Proposals for non-network options	18
Advisory bodies/ universities	5	General feedback on the RIT-T process	7
Manufacturers and other proponents	13	Feedback on market modelling approach	10
Total submissions	35	**Total submissions**	40

Totals are not the same as some submissions address multiple topics

Submissions have been taken into account in undertaking the assessment presented in this report. In particular, the development of a least cost network support option has drawn on the responses received, and some modelling input assumptions have been refined, including consideration of a broader range of future gas price scenarios.

The time that has elapsed since the publication of the PSCR, as well as the various policy and regulatory changes that have since been put in place means that in some cases points raised in submissions are now less relevant. We have described in this PADR how the changes in policy, particularly in relation to managing system security and system strength issues, are being reflected in the analysis. We welcome submissions to this PADR on the approach adopted.

The key issues raised in submissions relevant to the RIT-T assessment are summarised in the following subsections, by general topic.

4.1 Submissions on network options

We received several submissions that either commented on the network options presented in the PSCR, or proposed new network options, or variants of these options. The options and our consideration of each are summarised in Table 3.

Table 3 – Summary of network options proposed in submissions to the PSCR

Network option proposed	ElectraNet's response
An interconnector that would connect South Australia to both Queensland and New South Wales[27] Forming a secure interconnected loop between mainland NEM regions, by interconnecting South Australia to Queensland via either north-west New South Wales or a region in central Australia with undeveloped renewable resources.[28]	We have further refined the Queensland interconnector option proposed in the PSCR, to develop a credible option that connects northern South Australia to Queensland via New South Wales (ie, Option B).
A interconnector from Tungkillo to Moorabool via Horsham, using either 500 kV HVDC overhead line, or a combination of 500 kV HVDC overhead line and underground cables[29]	HVDC technology would be significantly more expensive than AC, for a similar capacity, and would not provide any additional system security benefits (as illustrated in section 9). ElectraNet does not therefore consider that these are economically feasible. In addition, new AC lines of greater than 275 kV capacity (ie, 330 kV or 500 kV) to Victoria are considered to not deliver additional market benefits commensurate with their additional costs – in particular, the increase of voltage levels to 500 kV would come at a much higher cost, and not be able to utilise the higher capacity (the inclusion of Option C.5 demonstrates this).

27 Geiser, T, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR* [via email], 1 December 2016.

28 University of Queensland, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, pp 3 - 5.

29 ABB, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 10 March 2017, pp 1-3.

Network option proposed	ElectraNet's response
An interconnector between the Snowy Mountains System in New South Wales with either South Australia, Queensland or Victoria.[30]	ElectraNet has tested a number of interconnectors connecting South Australia to an eastern state and has closely collaborated with AEMO in the preparation of the ISP. The ISP prepared by AEMO has considered a wide range of alternative interconnector capacities and routes.
An interconnector between Buronga and Robertstown and Wagga using either: • a single circuit 275kV line from Buronga to Robertstown, [31] • a double circuit 275 kV line from Buronga to Robertstown, a 275 kV line from Buronga to Darlington Point, and a 330 kV single circuit line from Wagga to Darlington Point, [32] or • a double circuit 330 kV line from Darlington Point to Robertstown, and a single 330 kV circuit line from Wagga to Darlington Point; [33]	ElectraNet has included three credible options from Robertstown to Wagga– ie, Option C.2 (a 275 kV line), Option C.3 (a 330 kV line via Buronga) and Option C.4 (a 330 kV line via Darlington Point). These options involve double-circuit lines since single-circuit lines do not provide sufficient capacity during a non-credible loss of Heywood. These options also extend lines to Darlington Point and Wagga, as outlined in section 6.
An augmentation of Murraylink to increase its capacity.	ElectraNet has included two credible options that look to expand the capabilities and/or capacity of the existing Murraylink interconnector (as proposed in the submission from Energy Infrastructure Investments). Option A includes a relatively low-cost upgrade to the capability of Murraylink that allows the connection to transport Frequency Control Ancillary Services (FCAS) (such an upgrade will not affect, either positively or negatively, Murraylink's capability to transport energy), while Option C.1 involves building a new DC link from Riverland SA to NSW ('Murraylink 2'), which is assumed to provide around 300 MW of new interconnection capacity.

We received submissions from Powerlink and TransGrid confirming their readiness to be proponents for transmission works for options in their jurisdictions, in the event that these are found to be the preferred option under this RIT-T.

30 ABB, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 10 March 2017, pp 4-5.

31 TransGrid, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 3.

32 TransGrid, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 3.

33 TransGrid, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 4.

Powerlink indicated its willingness to work with ElectraNet to assess the viability of an interconnector linking South Australia with Queensland and stated its commitment to: [34]

- refining the scope and likely cost of the credible HVDC voltage source converter (VSC) option between South Australia and Queensland;
- modelling the HVDC VSC link and converter station control systems to quantify the impact that prudent post-contingent control action on the link may have on transient, voltage, oscillatory and thermal limits of existing AC interconnectors; and
- identifying upstream limitations within the Queensland network and scoping and costing solutions to these limitations.

Furthermore, Powerlink stated:

> [i]n the event that a SA-Queensland interconnector is demonstrated to be the preferred option, Powerlink will participate in a manner consistent with its established role in developing, owning and operating the high voltage electricity network in Queensland.[35]

TransGrid communicated its support for an interconnector between New South Wales and South Australia, stating its willingness to be a proponent for the works in its jurisdiction:[36]

> Modelling has demonstrated that benefits across the NEM will more than outweigh the cost, leaving electricity consumers better off overall. TransGrid is ready to fund investment in an interconnector, should the RIT-T support this investment.
>
> TransGrid could construct an interconnector within 20-24 months from project approvals, depending on capacity. It is expected that project approvals would be able to be expedited given the importance of this project to South Australia's energy security.

Kimberly-Clark agreed with ElectraNet that an alternative route for any new interconnection was essential, because '…while upgrading the existing interconnector through Heywood might be the lowest cost option, it also recognises that as both circuits follow the same easement, and it is credible that both circuits of the Heywood interconnector might have to be shut down at the same time…' [37]

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[34] Powerlink, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 28 February 2017, p 1.

[35] Powerlink, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 28 February 2017, p 2.

[36] TransGrid, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 2.

[37] Kimberly-Clark, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*,1 February 2017, p 2.

A number of parties commented on the potential for an interconnector that would form a loop through NEM regions. The University of Queensland for example noted its support for such an interconnector.[38] Energy Infrastructure Investments (EII) raised concerns about the 'risk of loop flows on the HVAC network as a result of providing a HVAC interconnector between SA and NSW', stating that 'ElectraNet will need to address this in any further consideration of the interconnector between SA and NSW.'[39]

TransGrid stated that market modelling must be capable of accurately representing a loop structure between NEM regions.[40] One party requested that ElectraNet provides clarity on the implications for market modelling and market benefits of introducing loop flows across the NEM.

We have further refined the Queensland interconnector option proposed in the PSCR, to develop a credible option that connects northern South Australia to Queensland via New South Wales (ie, Option B outlined below). AEMO has explicitly considered the issue of loop flows as part of its 2016 NTNDP,[41] and ElectraNet and AEMO have also discussed this issue as part of the current RIT-T assessment.

4.2 Submissions in relation to network support technologies

The PSCR set out the required technical characteristics of network support technologies that could address the identified need, and sought submissions from proponents of network support solutions that could meet these criteria. ElectraNet also issued a further report, the PSCR Supplementary Information Paper in February 2017. This report provided further information on:

- the identified need and the likely nature of the services that could meet it;
- aggregate power system targets for service levels from network support solutions;
- the information that ElectraNet would require from proponents in order to assess their proposed solution options; and
- the process that ElectraNet proposed to adopt to review and assess network support solutions within the RIT-T.

In response, ElectraNet received 18 submissions from proponents of potential network support technologies. While the details of these proposals are commercial in confidence, the high-level options proposed were varied in terms of technology and included:

- standalone battery solutions, mostly using lithium ion technology, with total MW capacity ranging from 20 MW to 375 MW;
- storage and generation combinations, using a range of technologies, with total storage ranging from 10 MWh to 250 MWh;

38 University of Queensland, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 3.

39 EII, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 27 February 2017, p 6.

40 TransGrid, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 6.

41 AEMO, National Transmission Network Development Plan 2016, p. 88.

- standalone generation projects, using either gas and solar technology, with total MW capacity ranging from 620 MW to 950 MW;
- the use of network support agreements with existing generation within South Australia;
- the use of synchronous condensers;
- demand management (up to 200 MW); and
- AC line flow control hardware.

The expected costs were provided in some, but not all, submissions. Where costs were not included, we contacted the proponents of these network support technologies in March 2017 for additional information.

Several submissions, including some from network support proponents, EII, and Powerlink,[42] emphasised the expectation that ElectraNet should ensure that network support options are given adequate consideration and that these options are assessed in a robust and transparent manner in the RIT-T.

SEA Gas stated that it believed ‘a range of network support solutions to current and future challenges will be available’ and that these solutions would offer benefits such as flexibility of scale and geographic diversity, resulting in significant option value.[43] However, it raised concerns that the Market Modelling Approach and Assumptions Report did not adequately address how network support options would be assessed.[44]

A network support proponent suggested in its confidential submission that ElectraNet works closely with proponents of network support solutions to ensure solutions are not removed from consideration due to modelling techniques that penalise new technologies.

Epic Energy requested that ElectraNet took the deployment times of network support alternatives, which are relatively shorter than network options, into consideration in the RIT-T. [45]

Rule changes since the publication of the PSCR regarding managing system frequency and system strength have changed the nature of the network support option requirements. The construction of the Hornsdale and Dalrymple ESCRI batteries also impact on the future requirements for system security and therefore the requirements from non-network options.

AEMO’s identification of a system strength gap in South Australia is also leading to the expedited implementation of a synchronous condenser solution by ElectraNet that is expected to be in operation by 2020, and which is reflected in the base case for this RIT-T assessment.

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42 EII, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 27 February 2017, p 4; Powerlink, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 28 February 2017, p 2.

43 SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 27 February 2017, p 2.

44 SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* Attachment, 27 February 2017, p 8.

45 Epic Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 7.

Notwithstanding these changes to the nature of the non-network support required, we have drawn on the submissions to the PSCR and responses to requests for additional information, and engaged expert engineering advice from Entura to develop a least cost non-interconnector option to include in the RIT-T assessment.

Where the non-interconnector option has the ability to provide additional benefits from exceeding the relevant reliability standard, this has been incorporated in the RIT-T analysis. The primary drivers of additional benefits are the extent to which the non-interconnector option helps manage RoCoF at a time of non-credible loss of the Heywood interconnector and frequency response.

4.3 General information or feedback regarding the RIT-T process

Submissions to the PSCR raised a range of points about the RIT-T process. We summarise these, and our responses to each, according to five broad areas below.

4.3.1 The identified need

Inclusion of wholesale price impact in the identified need

Several parties raised concerns about the inclusion of reduced wholesale pricing in South Australia as part of the identified need for this RIT-T, and the risk this would lead to unequal weighting of other cost elements.

For example, AEMO stated that ‘by making regional wholesale pricing a specific element of the identified need, there is a risk that other cost elements (including network costs) might not be equally weighted’, which could result in the exclusion of cheaper network support options and conflict with the RIT-T objective of looking at benefits across the entire NEM. [46] AEMO suggested that the specific wholesale pricing driver be removed from the identified need. [47]

Similarly, Delta Energy stated that the RIT-T should assess ‘…all possible options that could deliver net economic market benefits, not simply potentially lower spot market prices in SA.’ [48] EII stated in its submission that making South Australian wholesale prices the primary focus of the benefit assessment ‘… will undervalue the need to provide technical solutions that provide stability to the network in terms of frequency and voltage and the importance of connecting lower CO2 emitting generation going forward.’[49]

To clarify, the intention of our analysis is not to attempt to capture lower wholesale prices as a RIT-T market benefit, but rather to help provide context for the extent of wholesale market changes brought about by a new interconnector. We have clarified the identified need in this PADR accordingly.

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46 AEMO, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 2.

47 AEMO, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 2.

48 Delta Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 3 February 2017, p 2.

49 EII, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 27 February 2017, p 2.

Specifically, the first driver of the identified need stipulated in the PSCR (ie, 'facilitating greater competition between generators in different regions, leading to lower dispatch costs and consequently lower wholesale prices, particularly in South Australia') has been changed to 'lowering dispatch costs in the NEM, particularly in South Australia, through increasing supply options across regions'.

We also received a submission from Engie that questioned the 'knock-on effects' of the identified need. Engie submitted that if wholesale electricity prices in South Australia decrease, South Australian generators will not remain viable and competition in the sector will be reduced.[50] We note that the RIT-T requires consideration of efficiency across the NEM as a whole, and that the impact of potential plant closures has been taken into account in the assessment.

Interaction between lowering emissions and other element of the identified need

Epic Energy submitted that an interconnector would be unlikely to achieve the identified need of transitioning to lower carbon emissions. It expressed the view that an interconnector would cause South Australia to rely on synchronous generation from high emissions coal fired power stations, conflicting with the identified need of transitioning to lowering carbon emissions.[51]

Epic Energy also disagreed that an interconnector would enable renewable energy resources in Queensland, New South Wales and Victoria to be unlocked, stating that 'while this observation applies to general interconnection within the NEM, constraints in South Australia's interconnection capacity have never been identified as an obstacle to renewable energy development in other states.'[52]

Epic Energy stated that 'the focus of the SAET needs to include increased security of electricity supply and transition to lower carbon emissions but note that these objectives should be met in the most economically efficient way.'[53]

Engie and another party who wished to remain confidential made submissions that questioned the ability of an interconnector to address the issues that arise from renewable energy generation, such as intermittency. Engie stated it did not believe that an interconnector would address issues with renewable energy integration, rather:[54]

> …it merely shifts it in the hope that the interconnected region will be able to deliver sufficient flexible generation capacity to meet its own needs as well as those of the South Australian region. It should also be remembered that the intention of interconnectors is to move surplus energy between regions and will never deliver firm generation capacity.

[50] Engie Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 3 March 2017, p 4

[51] Epic Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 6.

[52] Epic Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 7.

[53] Epic Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 2.

[54] Engie Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 3 March 2017, p 5.

Another confidential submission similarly argued that interconnectors merely move the problems associated with renewable penetration and retirement of baseload coal around, rather than solving them, and that the notion interconnectors tap into surplus baseload capacity is not compelling, moving into the future.

While it is true an interconnector may lead to a circumstance where coal output from other regions increases in response, by definition, the total costs of meeting emissions reduction targets decreases with the construction of an interconnector.

By spreading the impacts of the intermittency around the market, the available options for managing intermittency increase, thus improving the ability of the market to find the lowest cost solution to managing high renewables penetration and dispatchability requirements. As AEMO and others have observed, a more decentralised NEM needs to be a more interconnected NEM, in order to harness the value of this increasing supply diversity.

Snowy Hydro raised concerns about supply shortfalls, forecast in South Australia and Victoria in 2024 and in New South Wales in 2025. [55] It light of this, Snowy Hydro stated the importance of assessing costs and benefits across a wide range of supply and demand scenarios, across all NEM regions, to ensure spare capacity can be utilised across regions. [56]

The market modelling in this RIT-T takes into account emissions constraints consistent with meeting Australia's COP21 emissions targets (amongst other emission reductions futures/targets). As a consequence, the investments evaluated in this RIT-T explicitly capture the costs across the NEM as a whole of meeting this constraint with the investment in place, compared to with no investment proceeding.

Consistent with Epic Energy's submission, the focus is on identifying the most economically efficient solution across the NEM as a whole, as required by the RIT-T. Similarly, the market modelling identifies the least cost generation path going forward consistent with meeting system security and reliability requirements.

The investments considered under this RIT-T are required to meet these same conditions, and to provide an overall market benefit, compared with no investment proceeding.

4.3.2 Need to consider system security and stability

We received submissions from the University of Queensland, AEMO and the Australian Energy Council that supported incorporating system security into the modelling for this assessment.

55 Snowy Hydro, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 20 February 2017, p 2.

56 Snowy Hydro, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 20 February 2017, p 2.

AEMO stated that it supported the inclusion of requirements relating to 'system resilience, including system strength, as South Australia transitions to a low carbon future' as part of the identified need and suggested that the PADR '… should provide a technical assessment to demonstrate the effectiveness of the preferred solution in withstanding various contingencies.'[57]

The University of Queensland also suggested that ElectraNet investigate voltage stability issues and subsequent power system frequency issues when designing short term, mid-term and long term measures, as renewable penetration increases.[58] Similarly, the Australian Energy Council noted that modelling of interconnector options '…should take into account the secure operation of the network, including constraints and the impact of constraints on wholesale price outcomes.' [59]

Submissions also provided suggestions for how system security should be incorporated into the modelling. The University of Queensland suggested in its submission that options should be tested to ensure '…they could secure the South Australian power system following a separation event of the Heywood interconnection similar to the 28 September 2016 occurrence'.[60] The University of Queensland also suggested that benefits of strengthening the northern and western parts of the South Australian network to improve power system security to industry, for example Olympic Dam and Port Pirie, should be assessed and valued. [61]

AEMO suggested that the SAET should address '[w]hether any proposed interconnector option can deliver system resilience without operating below capacity or relying on control schemes and distributed services, and the resultant impact on potential market benefits'.[62]

AEMO further suggested that system resilience benefits should be described and matched with the components that deliver those benefits.[63] AEMO also suggested the modelling should ensure system resilience benefits are not double counted with other market benefits. [64]

AEMO suggested 'that the loss of multiple generators within the South Australian region should also be considered when assessing a system resilience benefit', and suggested that interconnector options should be supplemented with distributed services to address system strength. [65]

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57 AEMO, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, pp 1- 2.

58 University of Queensland, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 1.

59 Australian Energy Council, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 5.

60 University of Queensland, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 1.

61 University of Queensland, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 1.

62 AEMO, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 2.

63 AEMO, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 2.

64 AEMO, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 2.

65 AEMO, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, pp 1-2.

Submissions from Delta Energy and SEA Gas also raised concerns about the effect of an interconnector on system security. Delta Energy raised concerns that any new interconnection would reduce the viability of existing gas plants in South Australia through competition and result in additional renewable capacity, encourage by the Renewable Energy Target. [66] Delta Energy anticipates that the net effect of this would be a reduction in system security and reliability, which would negate some of the benefits initially delivered by the new interconnector.' [67] SEA Gas submitted that a new interconnector would not address system security challenges.[68]

The Australian Energy Council considers that the likely outcome of greater competition from low-cost interstate generators is a reduction in local firm generation in South Australia. In the long run, the council is concerned that, as conventional generation retires, the state would be completely reliant on the interconnectors themselves for security and reliability of supply.[69]

Our modelling recognises the system security issues in South Australia. Specifically, in the capacity expansion modelling system security issues are captured through the imposition of a cap on non-synchronous generation.

The presence of synchronous condensers is expected to increase the amount of non-synchronous generation that may be on-line in South Australia compared with AEMO's earlier analysis. AEMO's assessment is that the cap on non-synchronous generation may increase to around 1,870 MW (assuming zero flows over the Heywood interconnector), with increments and decrements to this cap depending on the level of export or import flows respectively over the Heywood interconnector. This assumption has been reflected in the market modelling for this PADR.

In addition, more detailed consideration of local system security issues has been assessed within the dispatch modelling. In particular, the modelling ensures that under each of the interconnector scenarios, system strength is maintained at the Robertstown node through either synchronous generation or network solutions, such as synchronous condensers. To be clear, the modelling assumes that even in a non-credible outage of the existing Heywood interconnector, South Australia can still operate in a secure state.

We are releasing a market modelling and technical assumptions report alongside the PADR, which provides details on the assumed constraints on synchronous and non-synchronous generation, as well as how system strength and security have been modelled more generally.

4.3.3 AEMO and AEMC review outcomes to be taken into account

ElectraNet received several submissions calling for the outcomes of reviews being undertaken by AEMO, the AEMC, and other regulatory bodies be taken into consideration in this RIT-T.

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[66] Delta Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 3 February 2017, p 1.

[67] Delta Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 3 February 2017, p 1.

[68] SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 27 February 2017, p 2.

[69] Australian Energy Council, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 5.

EnergyAustralia requested that we provide clarity around how benefits are affected by changes coming from AEMO's Future Power System Security program, and AEMC reviews and rule changes that are being undertaken.

Submissions from AEMO, Epic Energy and SEA Gas suggested that the results of AEMO's Future Power System Security program are incorporated into this RIT-T modelling, including an appropriate Rate of Change of Frequency standard. AEMO also noted that it actively supported the AEMC's System Security Market Frameworks Review and the Essential Services Commission of South Australia's review of technical standards for inverter-connected generators, and noted they were relevant for this RIT-T.

SEA Gas noted that the introduction of an inertia market and the system strength standards raised in the AEMC's System Security Frameworks Review could reduce the probability of non-credible separation of South Australia from the NEM, or decisions regarding generator entry and exit.

As discussed in section 2 above, the modelling we are undertaking and the results reported in this PADR incorporate the impacts of all relevant recent rule changes, including those related to the Rate of Change of Frequency Standard and system strength requirements.

4.3.4 Scope of benefits considered

Several submissions, including Snowy Hydro and the University of Queensland, called for the economic impact on all parties throughout the entire NEM to be included in our modelling, as opposed to those in a single region or sector. 70 In particular, Business SA submitted that it is important that assessments include benefits to multiple consumer classes, including large market customers that are also small to medium enterprises. [71]

We are assessing the NEM-wide benefits for each option in our assessment, consistent with the requirements of the RIT-T. That is, the assessment has not been limited to a single NEM region (eg, South Australia), and nor to only a sub-set of those in the market. Rather it captures the costs and benefits to all parties who produce, transport and consume electricity in the NEM.

Several submissions called for the wider economic and social implications of each option to be included in the assessment of benefits. For example, the South Australian Chamber of Mines and Energy (SACOME) stated, 'the inability to consider wider economic implications is a limitation of the RIT-T framework', and suggested 'that ElectraNet consider and provide supplementary analysis on these issues.' [72]

As noted by SACOME, the existing RIT-T framework does not allow consideration of benefits beyond of the NEM and therefore we are unable to incorporate wider economic benefits into the quantitative RIT-T assessment.

[70] University of Queensland, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 1; Snowy Hydro, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 20 February 2017, p 2.

[71] Business SA, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 1 March 2017, p 1.

[72] SACOME, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 1 March 2017, p 2.

However, we consider these benefits are important and recognise that they may be substantial. To address this, the potential for broader economic benefits to be unlocked is discussed in the qualitative description of the identified need in section 3.

We note that the benefits to the wider community and economy are not expected to influence the choice of any particular interconnector or non-interconnector option over another and that our RIT-T assessment has quantified sufficient benefits to find an investment is warranted.

The University of Queensland submitted that the economic benefit associated with 'unlocking' renewable energy potential in South Australia and along interconnector routes should be included as a benefit in the RIT-T. [73] We have picked up this benefit directly through the market modelling, as it includes the additional renewable generation capacity when it is the least cost way of meeting demand.

The Australian Energy Council wished to understand the trade-offs between different benefit categories, and specifically raised concerns that the relationship between price reductions through imports from jurisdictions with higher carbon intensity and the level of total emissions should be accounted for. [74] Section 9 presents a breakdown of estimated RIT-T cost and market benefit categories for each option, under a range of different scenarios. In addition, ElectraNet has also reported the expected change in the level of carbon emissions associated with each of the options considered.

SEA Gas interpreted section 4.3 of the Market Modelling and Assumptions Report as an indication that ElectraNet no longer considered competition benefits to be a compelling factor. [75] SEA Gas stated that it agreed 'that perceived competition benefits are highly tenuous' and 'queries whether the identified need upon which the RIT-T was originally based remained valid.' [76]

We did not intend to indicate that competition benefits are not relevant in the Market Modelling and Assumptions Report. Section 4.3 of this supplementary report, highlighted by SEA Gas, was intended to convey that the competition benefits arising from the options considered were similar in magnitude, and so are unlikely to affect the ranking of the options under this RIT-T, and not that the competition benefits were unimportant. ElectraNet reaffirms the identified need in this RIT-T.

4.3.5 Comparison of options

One party, who wished to remain confidential, raised concerns that different options would produce the highest benefit across different scenarios, and stated that the optimum option must be compelling across all scenarios. It also wished to be provided with information of how ElectraNet is weighting different scenarios and forecasts in its modelling. It was also concerned that the option ranking fails to assess the benefits, such as ancillary services or liquidity improvements in the contract market, due to its focus on market scenarios.

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[73] University of Queensland, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 1.

[74] Australian Energy Council, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 1.

[75] SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* Attachment, 27 February 2017, p 7.

[76] SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* Attachment, 27 February 2017, pp 6-7.

The modelling reported in this PADR shows that the identification of Option C.3i as the preferred option is robust across all of the different scenarios.

We have applied weightings to each scenario that reflect that the ‘base scenario’ is considered more likely, and has consequently been given a weight of 50%. The high scenario and low scenarios have each been weighted 25%, on the basis that there is no evidence to weight one more likely than the other. We have also tested the robustness of the overall outcomes to the scenario weightings assumed and found that the choice of weighting has no impact on the RIT-T outcomes.

We note that ancillary services (such as FCAS) have been considered, but are not expected to be material in terms of identifying the preferred option. They have therefore not been explicitly modelled in this RIT-T (as outlined in section 8.2). Liquidity improvements in the contract market have not been estimated as they are not captured under the RIT-T.

4.3.6 Assumptions underpinning each scenario

One party, that wished to remain confidential, raised concerns around the market benefit scenarios. In particular, it considered that the High, Central and Low scenarios may not in fact be indicative of likely High, Central and Low market benefit scenarios and stated that, taking carbon policies as an example, a strong carbon regime will drive the NEM to become more broadly like South Australia (less baseload coal, more intermittent renewables) so the expected benefit could be lower. It also stated that a high coal price would drive a low market benefit for interconnectors (and that the opposite would be true in terms of driving a higher market benefit).

The party suggested an alternative methodology to running the three scenarios would be to pick two key variables (preferably from the following: demand, gas price, coal price and capacity including retirements) and while keeping the other variables (eg Rate of Change of Frequency, Value of Customer Reliability, carbon pricing, new entry costs) constant prepare a two-by-two matrix to ascertain how the various options perform in a constrained range of circumstances.

The same party suggested that other key variables to include in modelling are black coal price, capacity requirements, deployment of storage, and gas price, while variables (including cost of new entry) could be de-emphasised.

We acknowledge that there are numerous sources of uncertainty regarding the future. We have tested different combinations of parameters to create the three scenarios investigated in this RIT-T assessment such that they cover a wide range of future states of the world and net benefits, and are generally aligned with those adopted by AEMO in the ISP.

We also conducted sensitivity analysis on gas price assumptions and other key variables. While we acknowledge that there are other assumptions that may have an impact on the estimates of net benefits, we believe that the scenarios investigated cover a sufficiently broad range of outcomes and cover a reasonable range of net benefits to give confidence in the overall outcome.

4.3.7 Augmentation technical report should be sought from AEMO

Epic Energy submitted that AEMO's augmentation technical report should be published well before the PACR.

Under the NER, AEMO is required to publish an augmentation technical report in relation to a proposed investment that will have a material inter-regional impact. The options considered in this report are expected to have a material inter-regional impact and we intend to request the augmentation technical report from AEMO ahead of publication of the PACR.

We also note that the findings of AEMO's ISP support the outcomes of this PADR.

4.4 Specific comments on RIT-T analysis

4.4.1 Inclusion of intra-regional transmission costs

Three submissions called for the inclusion of all intra-regional augmentation costs in the RIT-T analysis, ie, the cost of associated network augmentation within each jurisdiction that is not directly associated with interconnector construction. Specifically, Energy Infrastructure Australia, Delta Energy and Snowy Hydro all noted that the RIT-T interconnector options should include the cost of any network augmentations that would be required to deliver interconnector capacity. [77] Snowy Hydro called for these costs to be transparently presented in the PADR. [78]

We have included all associated intra-regional network augmentation costs in the RIT-T analysis. The costs of each option (both interconnector and intra-regional costs) are set out in section 9.1.

4.4.2 Valuing the impact of outages on customers

Business SA submitted that when ElectraNet assesses the costs of potential future outages, it should take into consideration that costs depend on the time of day: [79]

> *'…when ElectraNet is assessing costs related to potential future outages, it should also consider that the range of costs will depend on the time of day, which is particularly relevant for South Australia given the state-wide blackout occurred towards the end of the working day.'*

[77] EII, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 27 February 2017, p 6; Delta Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 3 February 2017, p 3; Snowy Hydro, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 20 February 2017, p 4.

[78] Snowy Hydro, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 20 February 2017, p 1.

[79] Business SA, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 1 March 2017, p 3.

The Australian Energy Council suggested that the value of customer reliability estimates resulting from the AEMC and Reliability Panel review into the System Restart Standard, undertaken in 2016 should be used in modelling, as they had 'undergone a transparent and rigorous review process through the AEMC's Reliability Panel.' [80]

We have assumed a VCR value in estimating the value of USE of $35/kWh, in line with AEMO's standard VCR estimates. As discussed in section 2.1, the introduction of various state and NEM-wide reliability requirements since the publication of the PSCR means that the focus of the system reliability and system security benefits of this RIT-T no longer depend on a reduction in the likelihood of an outage. As a consequence, the value of VCR adopted for the RIT-T assessment is not a key factor in the assessment.

4.4.3 Importance of considering investment to meet future challenges

AEMO supported ElectraNet's RIT-T process, and considered it to be an appropriate response to emerging system resilience challenges relating to South Australia energy mix.[81]

SACOME 'agrees that it is imperative to assess long term options to manage a changing and dynamic electricity system' and suggested that 'ElectraNet considers the potential consequences of a new interconnector on existing SA generators, and carefully review the location of the interconnector in light of stated renewable energy targets and planned coal generation closures in Victoria.'[82]

Snowy Hydro questioned the need for a large scale augmentation, such as an interconnector, in light of declining demand: [83]

> In recent years we have witnessed further absolute declines in demand across all NEM regions with the exception of Queensland. There is no concrete evidence that the recent history of declining demand will plateau and recover. Should these changes in demand persist, it calls into question the need for further substantial capital expenditure on large scale transmission augmentations.

Snowy Hydro advocated for the use of most recent demand forecasts in the RIT-T, and posited that declining demand may continue. [84]

The RIT-T assessment for the PADR has taken into account different assumptions relating to a continuation of low demand outcomes, and has adopted demand assumptions that are consistent with AEMO's forecasts. The assumptions made in relation to future alternative demand outlooks have been found to be not material in the context of the overall assessment outcomes.

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80 Australian Energy Council, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 6.

81 AEMO, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 1.

82 SACOME, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 1 March 2017, p 1.

83 Snowy Hydro, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 20 February 2017, p 3.

84 Snowy Hydro, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 20 February 2017, p 3.

The RIT-T assessment has also taken into account differences in emissions policies and potential renewable energy targets going forward. It has also reflected different assumptions in relation to future generation retirement, particularly the timing of the retirement of gas generation in South Australia.

4.4.4 Need to address uncertainty of long-lived interconnector assets

We received several submissions that noted the risks associated with a long-term investment such as an interconnector in the face of future uncertainties.

For example, SEA Gas noted that the NEM is experiencing unprecedented changes, which ‘creates enormous uncertainty as to likely future outcomes and thus an environment in which long term investment decisions carry a very high degree of risk.’[85] SEA Gas further noted that interconnectors ‘involve high capital costs…, take significant time to implement and require long payback periods.’[86]

Business SA noted that the economic life of a future interconnector could be compromised by emerging technologies and called for ElectraNet to ensure that these financial risks would not be passed on to South Australian electricity users.[87]

Engie highlighted in its submission that constructing an interconnector, a 30-plus year investment requiring large amounts of money, would lock South Australian consumers into a long-term cost that, given future uncertainties, may not achieve its stated needs. [88]

The Australian Energy Council suggested that, due to high levels of uncertainty, multiple future scenarios should be considered ideally through a probabilistic and risk adjusted method, such as a Monte Carlo simulation. [89]

Business SA queried whether ElectraNet was considering that future interconnectors may have shorter economic lives than those previously constructed, due to a higher asset redundancy risk. [90]

We agree that there are significant risks associated with a long term investment, such as an interconnector. However, it is also clear that currently the sector is in transition, and there are even more significant risks in taking no action to support this transition. There is widespread recognition that increased grid connection has a key role to play in that transition.

The ISP that has been prepared by AEMO, confirms that a new interconnector between South Australia and New South Wales is an important element of the ‘roadmap’ for the NEM and as one of its immediate priorities that would deliver positive net market benefits as soon as it can be built.

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[85] SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 27 February 2017, pp 1-2.

[86] SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 27 February 2017, p 2.

[87] Business SA, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 1 March 2017, p 3.

[88] Engie Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 3 March 2017, p 2.

[89] Australian Energy Council, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 1.

[90] Business SA, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 1 March 2017, p 3.

Future uncertainties have been incorporated into the RIT-T modelling via the adoption of scenario analysis, reflecting a wide range of potential outcomes across the key drivers of market benefit for the investments being considered – and in particular gas prices. The modelling presented in this PADR indicates that the preferred option is robust to the scenarios considered.

We have undertaken sensitivity analysis to better understand the drivers of net benefits to identify the option that is robust to different future changes in the market, and ideally offers positive net benefits under all reasonable scenarios as a 'no regrets' solution.

4.4.5 Assessment against 'do nothing'

Powerlink suggested that network options and network support alternatives should be assessed against a 'do nothing' option. [91]

In this RIT-T, ElectraNet has compared options with how the market would develop in the absence of a new interconnector or network support. In particular, it has considered several alternative 'do nothing' scenarios, which vary in terms of key parameters such as gas price, demand levels and emissions targets.

4.5 Feedback on the market modelling approach

This section summarises a range of points raised in submissions regarding the market modelling approach adopted.

4.5.1 Uncertainties when modelling benefits and costs

We received submissions from SEA Gas and Kimberly-Clark that suggested changes to assumptions included in modelling.

SEA Gas and Kimberly-Clark suggested changes to gas price assumptions. SEA Gas submitted that gas price assumptions taken from AEMO do not represent the full range of potential outcomes, that there was scope for gas prices to fall below the 'low scenario' described in the Market Modelling and Assumptions Report.[92] Kimberly-Clark called for sensitivity analysis for higher and lower gas prices. [93] Furthermore, Snowy Hydro requested that ElectraNet models a range of sensitivities for the differential between gas prices in South Australia and other NEM regions, to ensure that benefits of the interconnector remain if the gas price differential narrows. [94]

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[91] Powerlink, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 28 February 2017, p 1.

[92] SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* Attachment, 27 February 2017, p 3.

[93] Kimberly-Clark, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*,1 February 2017, p 2.

[94] Snowy Hydro, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 20 February 2017, p 4.

SEA Gas suggested that a wider range of forecast energy demand should be adopted, due to difficulty of accurately forecasting demand.[95] SEA Gas also suggested that potential changes to the supply demand balance resulting from, for example, the retirement of Hazelwood and notional capacity reserves in jurisdictions outside South Australia, should be considered.[96]

SEA Gas took issue with the WACC we proposed to use as the discount rate in the NPV assessment and suggested that the upper estimate should be substantially increased, unless another form of protection, such as a cap on allowable regulatory return, would apply.[97]

In response to these submissions, we have widened the assumed high and low forecasts for gas prices in the assessment, compared with those adopted by AEMO.

In particular, the 'high' scenario includes a gas price assumption of $3.50/GJ higher than the AEMO Neutral forecast and the low scenario reflects a gas price of $7.40/GJ (based on expert advice from EnergyQuest), which is below that assumed in AEMO's latest Gas Statement of Opportunities (GSOO).

In addition, uncertainty with regards to demand has been captured through the high, neutral and low scenarios which adopt high, neutral and low AEMO demand forecasts respectively.

We have not revised the WACC used as the discount rate in the NPV assessment.

The preferred option is robust and remains the preferred option across a wide range of future scenarios and sensitivity tests.

4.5.2 Assessment of option value

We received submissions from EII, Epic Energy and SEA Gas that queried how the RIT-T will account for the option value of proposed solutions.[98] EII requested that ElectraNet outline its approach to calculating the economic value of flexibility/ optionality with respect to delivery of projects.[99]

We do not consider that there is materially more (or less) option value between the credible options investigated, given the primary benefit of new interconnection is derived immediately from avoided fuel costs.

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95 SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* Attachment, 27 February 2017, p 4.

96 SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* Attachment, 27 February 2017, p 4.

97 SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* Attachment, 27 February 2017, p 5.

98 EII, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 27 February 2017, p 2; Epic Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 6; SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* Attachment, 27 February 2017, p 8.

99 EII, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 27 February 2017, p 2.

Therefore, we have not applied real option valuation techniques to explicitly model any ‘option value’ because doing so is a computationally intensive task that is unlikely to have a material impact on the relative ranking of options, or whether they deliver positive net benefits.

4.5.3 Treatment of state-based renewable energy targets

Several submissions raised the inclusion of renewable energy targets in the modelling.

Many submissions were supportive of the inclusion of renewable energy targets in the modelling. The Clean Energy Finance Corporation noted that recent recommendations by COAG require a RIT-T to include the potential benefits under carbon abatement and renewable energy policy. [100] Powerlink suggested that the range of scenarios for testing the options should include potential state based renewable energy targets. [101] Delta Energy submitted that the base case should include the impacts of the RET, an Emissions Intensity Scheme, and carbon policy targets at federal and state levels. [102]

Several submissions noted the uncertainties associated with future renewable energy target schemes. The Australian Energy Council and TransGrid noted the high degree of uncertainty around state based renewable targets, as they are subject to change. [103] SEA Gas raised concerns about how ElectraNet was incorporating emissions policies into the modelling, noting that renewable energy targets can impact the jurisdiction’s investment and generation mix, and that ElectraNet had only explicitly included Victoria’s renewable energy target in the modelling. [104]

Submissions also provided suggestions about how ElectraNet should approach modelling these schemes in the RIT-T. For example, Delta Energy suggested that the most likely carbon abatement mechanisms would be the Emissions Intensity Scheme, due to its low cost and minimal impact on system security. [105] The South Australian Chamber of Mines and Energy suggested that the RIT-T should conduct its assessment of options ‘in light of stated renewable energy targets.’ [106]

SEA Gas, submitted that proposed state based renewables targets should be considered in analysis. [107] TransGrid ‘…considers that transmission investment foreshadowed in response to VRET is uncertain and should not be assumed for the purpose of option evaluation.’ [108]

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[100] Clean Energy Finance Corporation, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 1.

[101] Powerlink, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 28 February 2017, p 2.

[102] Delta Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 3 February 2017, p 2.

[103] Australian Energy Council, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 8; TransGrid, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 6.

[104] SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* Attachment, 27 February 2017, pp 4 and 7.

[105] Delta Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 3 February 2017, p 2.

[106] SACOME, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 1 March 2017, p 1.

[107] SEA Gas, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* Attachment, 27 February 2017, p 4.

[108] TransGrid, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 27 February 2017, p 6.

Our modelling in this RIT-T is aligned with the assumptions adopted by AEMO in the ISP, and assumes that the VRET and QRET policies are delivered in full.

We also consider that implementation of the National Energy Guarantee (NEG) will not materially affect the results of the market modelling. This is based on the details released supporting the assumption that the NEG will deliver emissions reductions in line with the COP21 Paris commitments and that the reliability guarantee component of the NEG will deliver outcomes consistent with system security and reliability requirements.

4.5.4 Carbon pricing

We received several submissions with various suggestions for future carbon price assumptions.

Delta Energy submitted that the RIT-T base case should '…acknowledge the likelihood of a carbon pricing scheme implemented within the medium term...' [109]. While Snowy Hydro suggested that it would be reasonable to model scenarios with zero carbon price after the Emission Reduction Fund is schedules to close in July 2020. [110]

Business SA requested that ElectraNet explain its methodology for adopting a carbon emissions penalty factor of $100/t CO_2.[111] To clarify, we have not adopted an emissions penalty factor in the modelling, but rather have applied a mandatory constraint on emissions in line with the target level adopted in each scenario. No such constraint is applied for the Low case, which assumes no emissions reduction target is in place. This approach is in line with the approach adopted by AEMO.

ElectraNet's modelling has assumed compliance with the COP 21 Paris Agreement in the central case. Enforcing compliance with COP21 Paris Agreement within the modelling gives rise to least cost abatement outcomes that are approximately equivalent to the adoption of a national emissions trading scheme with the Paris Agreement as its target emissions level.

4.5.5 Cost of alternative technologies

Kimberley Clark raised concerns that assumptions regarding the future cost and uptake of alternative technologies might be too conservative. Specifically, it suggested that predicted battery storage costs should be lowered, and noted that forecasts of solar PV price and volume have consistently underestimated outcomes.[112]

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[109] Delta Energy, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 3 February 2017, p 2.

[110] Snowy Hydro, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 20 February 2017, p 4.

[111] Business SA, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 1 March 2017, p 3.

[112] Kimberly-Clark, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*,1 February 2017, p 2.

We note that AEMO has substantially reduced its assumptions in relation to future technology costs in its ISP assessment. We have assumed alternate technology costs in this PADR that are consistent with AEMO's lower ISP assumptions, and have tested a further reduction in costs as part of the 'low' scenario in this RIT-T. The assumptions made in relation to future alternative technology costs were not found to be material in the overall assessment outcomes.

4.5.6 Transparency of modelling

We received submissions from EII and Snowy Hydro that called for transparency in the modelling process, to ensure that stakeholders can verify the robustness of results.[113] EII requested that power flow modelling assumptions and information about the adequacy of the network are made explicit, while Snowy Hydro requested the details of modelling assumptions and sensitivities be published.[114]

A network support proponent requested more clarity around the basis on which the first-pass options will be screened and determined, including what criteria are used and how ranking will be undertaken, and the time horizon being modelled in the scenarios.

A confidential submission requested that ElectraNet provides clarity on the consistency of this RIT-T and AEMO's annual National Transmission Network Development Plan, with regard to process and assumptions. It also requested that ElectraNet provides clarity on how it is dealing with the introduction of new fast-start plants, which could provide ancillary services and energy services after a contingency.

We understand the importance of transparency in the RIT-T process and have endeavoured to release all the information necessary for stakeholders to assess the robustness of the modelling results.

We note that a market modelling report is being released alongside this PADR, which provides further details on the modelling undertaken for this PADR. We have also addressed consistency of the RIT-T assessment with AEMO's ISP.

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[113] EII, Submission in relation to South Australian Electricity Transformation RIT-T PSCR, 27 February 2017, p 5; Snowy Hydro, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 20 February 2017, p 2.

[114] EII, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR*, 27 February 2017, p 5; Snowy Hydro, *Submission in relation to South Australian Electricity Transformation RIT-T PSCR,* 20 February 2017, p 2.

5. Four credible options have been assessed for this RIT-T

We have investigated variants of four credible options as part of this RIT-T assessment, comprising options involving new interconnectors to the three neighbouring NEM states, as well as a local South Australian 'non-interconnector' option. These options are summarised in Table 4.

Table 4 – Summary of the four credible options assessed in this RIT-T

Overview	Distance (km)[115]	Capital cost ($bn)[116]	Annual contract cost ($m)	Notional Maximum Capability (MW)	
				Heywood	New interconnector
'Non-interconnector' option					
Option A – Least cost non-interconnector option in SA	NA	–	130	650	–
An interconnector to Queensland					
Option B – HVDC from north SA to Qld	1,450	1.8	–	750[117]	700
New South Wales interconnector options					
Option C.1 – New DC link from Riverland SA to NSW ('Murraylink 2')	370	0.8	–	750	300
Option C.2 – 275 kV line from mid-north SA to Wagga Wagga NSW, via Buronga	920	1.0	–	750	600
Option C.3 – 330 kV line from mid-north SA to Wagga Wagga NSW, via Buronga	920	1.4	–	750	800
Option C.3i – 330 kV line from mid-north SA to Wagga Wagga NSW, via Buronga, plus series compensation (or similar)	920	1.5	–	750	800
Option C.4 – 330 kV line from mid-north SA to Wagga Wagga NSW, via Darlington Point	910	1.3	–	750	800

115 All distances are approximate.

116 All options are based on a preliminary design have been designed and costed, to be consistent with the relevant Australian Standards.

117 The increase in capacity from the base case for all interconnector options is due to the additional transient stability provided due to the series compensation of the South East to Tailem Bend lines and the connection of the new interconnector

Overview	Distance (km)[115]	Capital cost ($bn)[116]	Annual contract cost ($m)	Notional Maximum Capability (MW)	
				Heywood	New interconnector
Option C.5 – 500 kV line from Northern SA to east NSW	1,200	2.9	–	750	1,000
A new interconnector to Victoria					
Option D – 275 kV line from central SA to Victoria	420	1.2	–	750	650
Option Di – 275 kV line from central SA to Victoria plus series compensation (or similar)	420	1.2	–	750	650

All network options also include a Wide Area Protection Scheme (WAPS) to prevent cascaded tripping of the new interconnector and the Heywood interconnector following non-credible loss of either one.

In the market modelling, combined interconnector limits have been applied to ensure that the loss of either interconnector will keep the remaining interconnector intact. The scope of the WAPS will be different to the recently deployed SIPS in that the current scheme is focussed on managing the loss of multiple generators in South Australia, to prevent separation from the NEM.

Since the PSCR was released, ElectraNet has undertaken a detailed pre-screening assessment of potential credible options, including a variety of possible interconnector routes and capacities[118]. The outworking of this process has been to refine the list of credible interconnector options from that presented in the PSCR.

In short, the key findings from the pre-screening assessment are as follows:[119]

- overall, any new interconnector needs to be similar in size to the Heywood interconnector (ie, 650 MW), to be able to cater for the loss/ tripping of the new interconnector[120] – this led to the majority of the interconnector options being assumed to be between 600-800 MW,[121] with the exception of the 'Murraylink 2' option (Option C.1);

118 ElectraNet's approach to undertaking this pre-screening was set out in the supplementary Market Modelling Approach and Assumptions Report released 21 December 2016, see: ElectraNet, *South Australian Energy Transformation RIT-T: Market Modelling Approach and Assumptions Report*, 21 December 2016, pp. 9-13.

119 Specifically, the PSCR included four high-level interconnector options determined primarily by route – ie, in the PSCR: Option 1 related to a new line from central SA to Victoria; Option 2 related to a new line from mid-north SA to NSW; Option 3 related to a new line from Northern SA to NSW; and Option 4 related to a new line from Northern SA to Queensland.

120 In effect, this assumes that both interconnectors would be 'protected events'. ElectraNet notes that AEMO may potentially operate these as if they are not protected – doing so, would increase the market benefits but also introduce an unserved energy risk.

121 The exception is Option C.5, which has been included to further investigate a 500 kV line (from northern South Australia to eastern NSW).

- for interconnection to Queensland, the long distance dictated the use of HVDC as the preferred transmission technology (as opposed to HVAC), even with the added expense of DC terminal stations, due to its expected lower cost overall;

- for new interconnection to New South Wales:
  - capacity limits of 275 kV and 330 kV lines mean that a line of one of these voltages from northern South Australia to Mount Piper in New South Wales was considered to not be technically feasible at any cost; and
  - a DC line from northern South Australia to east NSW was considered to be highly inflexible and expensive to connect/ cut into;

- for new interconnection to Victoria:
  - expanding the existing Heywood interconnector was ruled out since it would not provide any additional benefits in terms of system security due to lack of diversification;
  - HVDC technology would be significantly more expensive than HVAC for similar capacity over the relatively short distance, and would not provide commensurately greater market benefits; and
  - new HVAC lines of capacity greater than 275 kV (ie, 330 kV or 500 kV) would not deliver additional market benefits commensurate with their additional costs – in particular, the increase of voltage levels to 500 kV would come at a much higher cost, and the assessment shows that the higher capacity would not be able to be utilised (the inclusion of a 500 kV option to New South Wales in this RIT-T assessment also demonstrates this).

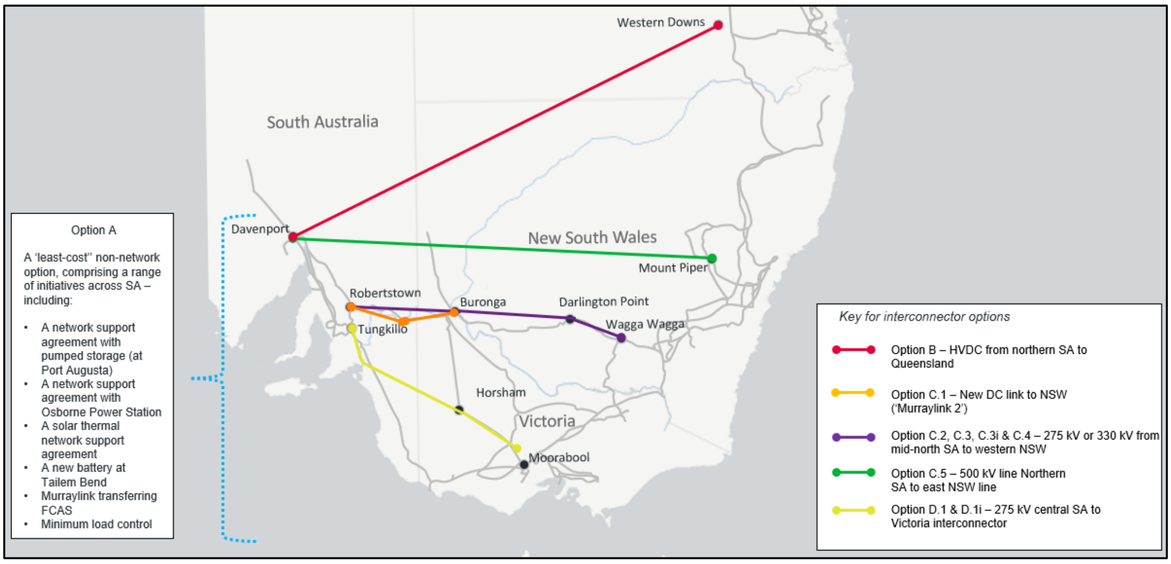
We also considered the staging of investment for all interconnector options as part of the pre-screening exercise. Key conclusions from this assessment were that:

- it is uneconomic to partially build HVAC lines, eg, string one side of double circuit line initially – in particular, the additional cost to string both sides initially is only marginally more expensive than the initial cost of stringing one-side (the logistics of live-line stringing a second line would also be more complex, and have a significant cost); and

- while there may be initial savings in converter costs from building to HVDC transmission systems as monopole initially (and augmenting to bi-pole in the future), the significant distance involved for the Queensland option (Option B) means that overall a staged option would come at a higher cost.

The credible options assessed are illustrated in Figure 1 below.

Figure 1 – Overview of the options (and variants) assessed[122]



We chose start and end locations for each interconnector option on the basis of minimising the total line lengths required to be built, and to ensure that the assumed connection points have sufficient deeper intra-regional network capability to carry the full capability of the interconnector, under typical conditions.

Under all new interconnector options, existing inertia constraints on the Heywood interconnector are assumed to be removed. The interconnection between South Australia and the rest of the NEM under the new interconnector options is designed and operated to withstand the non-credible loss of the Heywood interconnector (and vice versa). A shortage of inertia will therefore only occur if a NEM-wide shortage were to occur, which is not a factor influencing the outcomes of this RIT-T.

We received 18 submissions on the PSCR from network support proponents. These submissions helped us shape a standalone non-interconnector option (Option A) in the RIT-T assessment. ElectraNet engaged engineering consultants Entura to provide technical advice on how network support technologies could assist, particularly in relation to providing system security, and in identifying an optimal standalone non-interconnector option.

Each of the four credible options, and their variants, are outlined in-detail in the sections below.

[122] Interconnector routes shown on this figure are only indicative (straight-line) and have been included for illustrative purposes. The figure shows major transmission lines in the NEM, but does not delineate between the capacity of these lines for ease of exposition.

5.1 Option A: Non-interconnector option

The PSCR included a generic non-interconnector option, which outlined how network support options could be utilised to help address the identified need. We invited submissions from potential network support proponents to help further refine this option for the purposes of the RIT-T assessment. We received 18 submissions on the PSCR from network support proponents.[123]

Since the PSCR submissions were received, the following exogenous events have had a direct impact on the composition of non-network components making up any non-interconnector solution:

- the development of the Hornsdale 100 MW battery
- the conclusion of the AEMC Emergency frequency control schemes Rule change in March 2017 – the key implication being that a SIPS is currently being implemented in South Australia to comply with the new requirements; and
- the conclusion of system security rule changes by the AEMC (ie, system strength and inertia), which resulted in a system strength gap being declared – and the subsequent expedited implementation by ElectraNet of a synchronous condenser solution to meet this gap, that is expected to be in operation by 2020. We have assumed a six high inertia synchronous condenser solution in the base case to meet this gap.

ElectraNet engaged engineering consultants Entura to provide technical insight into how network support technologies could assist, given the submissions received and taking into account these external changes, and to develop a least cost non-interconnector solution for inclusion in the RIT-T assessment.

The non-interconnector option has been scoped to prevent a system black event that would likely occur from a loss of the existing Heywood interconnector as the initiating event.

The key components of the least cost non-interconnector solution considered in this PADR, and the aggregate average annual cost of this solution (under the central scenario) are set out in Table 5.

[123] A summary of submissions can be found in Section 4.

Table 5 – Non-interconnector option components

Component (Network support agreement)	Average annual contract cost ($m)	Capital cost ($m)	Operating cost ($m)	Available from
Pumped Storage (Port Augusta)				
Osborne cogeneration				
Solar thermal at Davenport				
BESS – Tailem Bend				
Murraylink (Transfer of FCAS)				
BESS (location to be determined)				
Minimum load control				
Total combined cost	**$130**	**3.0**	**1.0**	**2020-23**

The majority of the non-interconnector option components would be procured by ElectraNet under a network support contract (to be recovered as a regulated cost pass through), and would not involve any direct operating and capital expenditure associated with that component. The exception is the installation of minimum load control to enable the control of solar PV installations, which would be directly invested in by ElectraNet.

Further detail on each of these elements is presented in the Entura report, which is being released alongside this PADR. Key outcomes of the Entura report are as follows:

- The non-interconnector option does not meet the defined minimum system performance levels under all conditions. While full compliance with the minimum performance requirements is technically feasible Entura does not consider the additional cost of supports provides sufficient value. That is, the standards achievable through a second interconnector are not always exactly replicable by a single interconnector coupled with supports.

- Although gas fired power stations may not remain economically viable, it is assumed that the current fleet (or equivalent) will remain available for the planning horizon of this study. This is necessary to make the South Australian island operable under all circumstances.

- The continued growth in rooftop PV installations is leading to the minimum grid demand approaching zero in the mid-2020s. Without an additional interconnector, future rooftop PV installations will have to be controllable in order to disconnect them when operating as an island. To enable this, policy changes may be required.

The above outcomes indicate that the non-interconnector solution includes a number of risks and uncertainties that have not been fully accounted for in this PADR assessment. To fully account for these factors the cost of this option would increase further.

5.2 Option B – HVDC from northern SA to Queensland

Option B involves a high capacity HVDC interconnector between South Australia and Queensland and is assumed to provide 700 MW of capacity. The indicative path is assumed to be between Davenport in South Australia, crossing into New South Wales and connecting with the Queensland network at Western Downs. This path would be around 1450 km in length.

The key components of this option are as follows:

- a new VSC bi-pole from Davenport 275 kV to Western Downs 275 kV;
- HVDC converters;
- HVDC lines; and
- Converter transformers.

Strong connection nodes at both ends means that there would be reduced risk of constraints over the interconnector under Option B compared to the New South Wales interconnector options (with the exception of C.4 and C.5).

Capital costs for this option are estimated to be in the order of $1,790 million. Construction is expected to require 2-3 years, with commissioning possible by the end of 2023, subject to obtaining necessary environmental and development approvals.

We note that HVDC options are a lot more expensive than HVAC equivalents for short to medium distance interconnections due to high converter station costs, but are more economical for higher capacities and longer distances. As outlined at the start of this section, the pre-screening assessment undertaken after the PSCR found that the distance considered for Queensland interconnection is so great that HVDC is the preferred transmission technology (as opposed to HVAC), even with the added expense of HVDC terminal stations.

5.3 Option C – New interconnection between South Australia and NSW

5.3.1 Option C.1 – New DC link from Riverland SA to NSW (‘Murraylink 2’)

Option C.1 involves constructing a new DC link from the Riverland region in South Australia to New South Wales, which would be similar in route and capacity to the existing Murraylink, and so has been titled ‘Murraylink 2’.

In particular, Option C.1 would involve a new link with cable and overhead sections that would connect between Berri in South Australia and Buronga in New South Wales.[124] This link would be around 370 km and is assumed to provide 300 MW of capacity.

The key components of this option are as follows:

- A new double circuit 275 kV transmission line between Robertstown and Berri;

[124] We note that the existing Murraylink interconnector run from Berri to Red Cliffs in Victoria, which is around 20 km south of Buronga.

- 275/132 kV transformer substation located near Berri, with a 132 kV connection to Murraylink's western terminal at Monash; and
- A new DC link (Murraylink 2) with cable and overhead sections would connect between Berri in South Australia and Buronga in NSW.

Option C.1 is the lowest capacity option of all interconnector options assessed and is expected to provide 300 MW of new interconnection capacity.

Option C.1 has been informed primarily by Energy Infrastructure Investments' submission to the PSCR. In particular, this submission raised that it included a contingent project for duplication of Murraylink as part of the most recent revenue proposal submitted to the Australian Energy Regulator (AER) (which includes 275 kV circuits from Robertstown to Berri, and HVDC link to Buronga, then through to Darlington Point).[125]

Capital costs for this option are estimated to be in the order of $810 million. Construction is expected to require 2 years, once all project approvals have been obtained, with commissioning possible between 2022 and 2024, subject to obtaining necessary environmental and development approvals.

5.3.2 Option C.2 – 275 kV line from mid-north SA to Wagga Wagga in NSW, via Buronga

Option C.2 involves constructing a new 275 kV line from the mid-north region of South Australia to Wagga Wagga in New South Wales. The indicative route investigated runs approximately 920 km from Robertstown in South Australia via Buronga in New South Wales and through to Wagga Wagga. This option is assumed to provide 600 MW of capacity.

The key components of this option are as follows:

- a 275 kV double circuit line from Robertstown to Buronga;
- 275/220 kV transformation at Buronga;
- a new single circuit line 275 kV line from Buronga to Darlington Point;
- a 275/330 kV transformer at Darlington Point;
- a new 330 kV single circuit line from Darlington Point to Wagga Wagga; and
- 275 kV Phase Shifting Transformers126 (PSTs) at Buronga.

Option C.2 is the smallest capacity of all the HVAC interconnector options assessed and is expected to provide 600 MW of new interconnection capacity.

[125] In its Final Decision, the AER accepted this project as a contingent. See: AER, *Murraylink transmission final determination 2018–23*, Overview, p. 22. Stage 3 has not been assumed. Including stage 3 would see this option be higher cost and lower capacity that option C.2.

[126] Phase Shifting Transformers (PSTs) are devices to control the flow on the new interconnectors, as the new interconnectors have a higher impedance compared to then Heywood Interconnector flow path, and therefore inherently will not be able to share much power across the interconnectors

Capital costs for this option are estimated to be in the order of $1,040 million. Construction is expected to take 2 years, once all project approvals have been obtained, with commissioning possible by the end of 2023, subject to obtaining necessary environmental and development approvals.

5.3.3 Options C.3 and C.3i – 330 kV line from mid-north SA to Wagga Wagga in NSW

Option C.3 involves constructing a new 330 kV line from the mid-north region of South Australia to Wagga Wagga in New South Wales, via Buronga. As with Option C.2, the indicative route investigated runs approximately 920 km from Robertstown in South Australia via Buronga in New South Wales and through to Wagga Wagga. This option is assumed to provide 800 MW of capacity.

The key components of this option are as follows:

- a new 330 kV double circuit line from Robertstown 330 kV to Buronga 330 kV;
- a new 330 kV double circuit line from Buronga to Darlington Point;
- a new single circuit 330 kV line from Darlington Point to Wagga Wagga;
- new 275/330 kV transformers at Robertstown;
- new 330 kV Phase Shift Transformers at Buronga; and
- a new 330/220 kV transformer at Buronga.

The key difference between this option and Option C.2 is the higher capacity of the new lines (ie, 330 kV rather than 275 kV).

Capital costs for this option are estimated to be in the order of $1,440 million. Construction is expected to require 2 years, once all project approvals have been obtained, with commissioning possible between 2022 and 2024, subject to obtaining necessary environmental and development approvals.

Option C.3i is a variant on the above option that also includes 50% series compensation between Robertstown and Buronga, to reduce constraints that would otherwise occur on the combined capacity of the existing Heywood interconnector and a new interconnector.[127] This increases the effective capacity across both interconnectors from around 1,150 MW to 1,300 MW. This option would cost an additional $40 million over Option C.3, but would not alter the above investment timing.

5.3.4 Option C.4 – 330 kV line mid-north SA to Wagga Wagga NSW, via Darlington Point

Option C.4 involves building a new interconnector of the same capacity as Option C.3 (ie, 330 kV) from the mid-north region of South Australia to Wagga Wagga in New South Wales. This option is assumed to provide 800 MW of capacity.

[127] The exact nature of the configuration of this option will be refined. Series compensation has the potential to restrict the connection of renewable generators to this path which will directly impact on the benefits of this corridor.

The key difference between Option C.4 and Option C.3 is that it bypasses Buronga in western New South Wales and connects into Darlington Point in central New South Wales which is expected to reduce the total line length to 910 km. This avoids linking into the Victorian network directly.

Option C.4 has been introduced since the PSCR. It has been developed following additional analysis by TransGrid, following release of the PSCR, regarding how to optimally streamline the capacity in central NSW.

The key components of this option are as follows:

- new Robertstown-Darlington Point 330 kV double circuit lines;
- An intermediate switching station mid-way with necessary reactive plant, to manage voltages;
- an additional Darlington Point-Wagga Wagga 330 kV line;
- new 275/330 kV transformers at Robertstown; and
- new Phase Shift Transformers at Darlington Point.

Capital costs for this option are estimated to be in the order of $1,280 million. Construction is expected to require 2 years, once all project approvals have been obtained, with commissioning possible between 2022 and 2024, subject to obtaining necessary environmental and development approvals.

5.3.5 Option C.5 – 500 kV line Northern SA to east NSW line

Option C.5 is a high capacity New South Wales interconnector option and involves constructing a 500 kV line from the northern region of South Australia to eastern New South Wales. It is modelled to provide 1,000 MW of notional maximum capability, which is the highest of all interconnector options considered.

The indicative route investigated runs approximately 1,200 km from Davenport in South Australia to Mount Piper in New South Wales.

The key components of this option are as follows:

- a 500 kV double circuit line from Davenport to Mount Piper;
- two 275/500 kV transformers at Davenport;
- two 500/500 kV PST transformers at Mt Piper; and
- Intermediate switching stations to manage reactive power with associated reactive plant.

A key difference between this option and the 330 kV New South Wales options (ie, Options C.3, C.3i and C.4), is that it runs another approximate 320 km into New South Wales. This is to ensure that the new 500 kV line can connect into the 500 kV network in New South Wales at Mount Piper – Options C.3 and C.4 connect in at Darlington Point, which only has 330 kV capacity.

Capital costs for this option are estimated to be in the order of $2,860 million. Construction is expected to require 2 years, once all project approvals have been obtained, with commissioning possible by the end of 2023, subject to obtaining necessary environmental and development approvals.

Strong connection nodes at both ends means that there will be reduced risk of constraints under Option C.5 compared to other New South Wales interconnector options.

5.3.6 Optimisation of the options to New South Wales

There are a number of aspects of the options to NSW that require further investigation, to optimise the final scope. These include (but are not limited to):

- The deployment of fixed series compensation on lines poses the risk of sub-synchronous resonance and sub-synchronous control interactions, if new generators are connected in the proximity to the series capacitors – considering that the Robertstown to Buronga line traverses Renewable Energy Zones, this aspect needs to be investigated further;

- Optimising the angle of phase shifting transformers will also be considered, as series compensation will reduce the requirement for larger angles;

- We are examining the potential benefits of strengthening the link between Buronga in New South Wales and Red Cliffs in Victoria – this would involve an additional 24 km of transmission upgrades likely operating at 220 kV with an estimated cost in the order of $40 million to facilitate the connection of additional solar capacity in western Victoria providing increased access to the Sydney and Adelaide load centres; and

- The deployment of additional plant to ensure that constraints are removed from existing renewable generators and future generators that will be connected in South Australia (with or without a new interconnector in place)

The outcomes of this analysis would influence options C1, C2, C3 and C3i, all of which pass through Buronga.

Option C4 bypasses Buronga and is therefore unlikely to be impacted by these further considerations.

5.4 Option D and Di – 275 kV central SA to Victoria interconnector

Option D has been designed to utilise the capacity around Horsham in Victoria to strengthen South Australia's connection to the east coast by providing an increase in export and import capability.

The indicative route investigated runs approximately 420 km from Tailem Bend in South Australia to Horsham in Victoria.

The key components of this option are as follows:

- a new double circuit 275 kV line from Tungkillo to Horsham;
- replacing the existing Horsham to Ballarat (including all sections in-between) single circuit 220 kV line with a double circuit line; and
- new 275/220 Phase Shifting Transformers at Horsham.

A maximum transfer capacity of 650 MW has been assessed for Option D. As outlined at the start of this section, this is due to the existing capacity of Heywood (ie, 650 MW) and needing to be able to cater for the loss/tripping of any new interconnector option.

As part of the pre-screening of options undertaken after release of the PSCR, we considered a new 700 MVA HVDC line from Robertstown in South Australia and Victoria. However, it was ultimately considered that HVDC technology would be significantly more expensive than the AC option, for a similar capacity, and not provide anything additional benefits from a system security perspective. Further consideration of this option was therefore discontinued.

Capital costs for this option are estimated to be in the order of $1,200 million. We have also incorporated the costs of 'network hardening' to reflect the operational risks associated with this bushfire prone region. A severe bushfire could lead to coincident and wide spread damage to both the existing Heywood interconnector and a new interconnector, raising the prospect that an outage of both interconnectors could be reclassified by AEMO as a credible contingency.[128] Specifically, we have included the costs of providing firm supply in South Australia based on the costs of 300 MW of OCGT generation ($298 million).

Construction is expected to require 2 years, once all project approvals have been obtained, with commissioning possible by the end of 2023, subject to obtaining necessary environmental and development approvals.

Option Di includes 50% series compensation between Horsham and Tungkillo, to reduce constraints that would otherwise occur on the combined capacity of the existing Heywood interconnector and a new interconnector. This increases the effective capacity across both interconnectors from around 950 MW to 1,100 MW. This option would cost an additional $30 million over Option D, but would not alter the above investment timing.

This option is influenced by the outcomes of the Western Victoria Renewable Integration RIT-T currently being undertaken by AEMO. The AEMO RIT-T is considering, amongst other things, increasing interconnection between the Melbourne load centre and Ararat in Western Victoria. ElectraNet has considered this outcome as a sensitivity that reduces the cost of Option D by $239 million, reflecting that this work may happen as part of this separate investment process.

[128] Presently, when the Heywood interconnector is operated at risk of separation, the interconnector is restricted to 50 MW into South Australia. This operation is assumed to continue if both paths were at risk of credible separation. The combined import capability of the two interconnectors is 950 MW, 300 MW greater than the current combined import capability, and hence creating a further 300 MW deficit under this operating condition.

6. Estimating net market benefits

The RIT-T requires many of its designated categories of market benefit 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 credible 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 investment as well as unrelated future transmission investment.

We have adopted a wholesale market dispatch modelling approach to calculate market benefits associated with the credible options included in this RIT-T assessment.[129]

Our earlier Market Modelling Assumptions and Analysis Report provided details on the overall approach that we proposed for the wholesale market modelling, as well as the key assumptions we intended to use.

We have considered submissions made in response to this report, and have taken these into account in the modelling presented in this PADR, where relevant. We have also reflected the impact of policy and regulatory developments that have occurred since the publication of the earlier reports in the wholesale market modelling. This includes updating the assumptions used to reflect those adopted by AEMO for the ISP in all areas where they could have a material impact on the outcome of the RIT-T assessment.

This section provides an overview of the market modelling undertaken for this RIT-T. We are publishing a separate modelling report alongside this PADR which provides greater detail on the modelling approach and assumptions, including detail on the technical constraints adopted, to provide transparency to market participants.

6.1 Overview of the market modelling

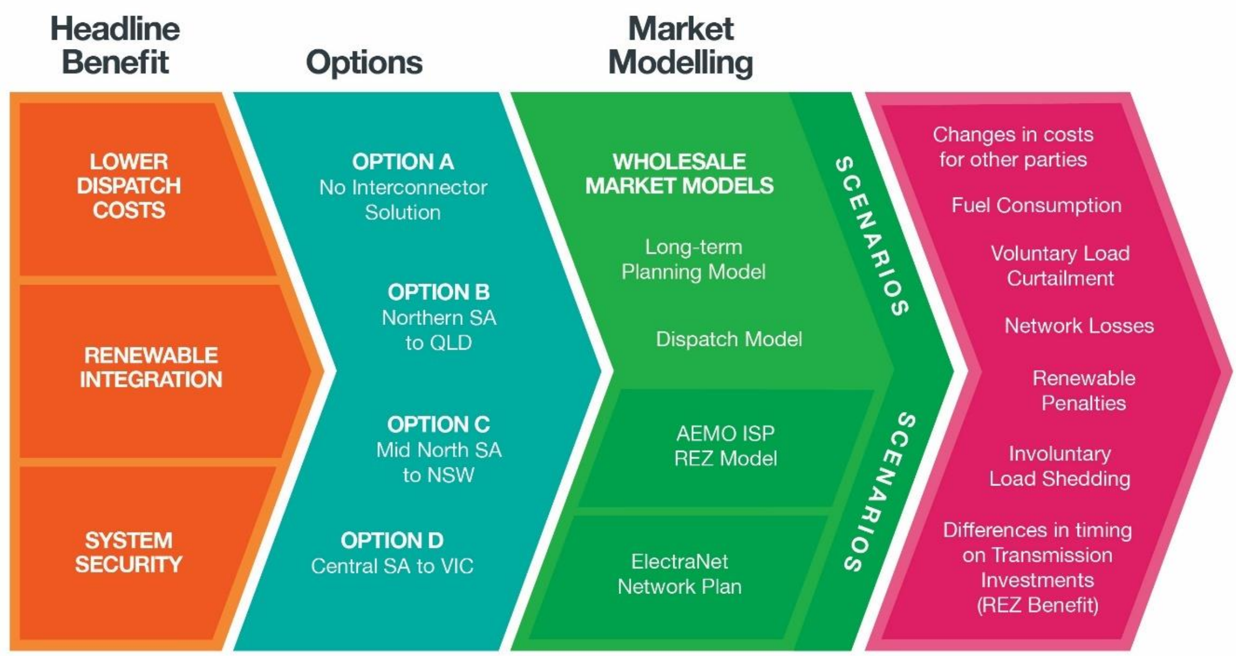
We performed detailed market modelling in PLEXOS to assess the market benefits of the various credible options over three future scenarios as well as a number of sensitivities.

A high-level summary of the market modelling undertaken is illustrated in Figure 2.

There are three key components of the market modelling – the long-term expansion model, the time sequential dispatch model and the network representation. Each of these elements is discussed in the accompanying modelling report.

129 The RIT-T requires that in estimating the magnitude of market benefits, a market dispatch modelling methodology must be used, unless the TNSP can provide reasons why this methodology is not relevant. See: AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 11, p. 6.

Figure 2 – Overview of the market modelling



In the earlier Market Modelling Assumptions and Analysis Report, we outlined a proposed 'three-phase approach' to undertaking the market modelling. In practice, due to the significant range of net benefits for each credible option across the scenarios considered, there has been limited potential for discarding options as the assessment has proceeded.

As a consequence, the market modelling presented in this PADR has been undertaken for all ten credible options, and across the full range of scenarios. Sensitivities have however been applied selectively where considered most relevant to developing confidence in the outcomes of the assessment.

6.2 Changes to the modelling assumptions from the PSCR

Key changes in the market and regulatory arrangements since the publication of the PSCR have been reflected in the market modelling. The most significant changes are:

- an updating of all material assumptions to reflect those adopted by AEMO in the ISP – this includes incorporation of state renewable energy targets (VRET and QRET) in all modelling scenarios;
- inclusion in the market modelling of a new battery storage facility at the Hornsdale Wind Farm, following the installation of this facility;
- inclusion of six high inertia synchronous condensers in South Australia in all scenarios, to satisfy the minimum system strength requirement identified by AEMO; and

- incorporation of a cap on non-synchronous generation in South Australia, consistent with system strength requirements – AEMO's assessment is that the cap on non-synchronous generation may increase to around 1,870 MW in the presence of the synchronous condensers (assuming zero flows over the Heywood interconnector), with increments and decrements to this cap depending on the level of export or import flows (respectively) over Heywood.

The proposed federal Government's NEG is reflected in the modelling through the inclusion of a constraint on overall emission levels that reflects Australia's COP 21 commitments, as well as a constraint on generation planting to ensure that the NEM reliability standard is met in all future periods.[130] Although the detailed design of the NEG is still being finalised, it is intended to ensure full compliance with these emission and reliability requirements consistent with the modelling assumptions adopted.

In addition, we have assumed that any new interconnector (and also the existing Heywood interconnector) would be operated in a way that ensures the South Australian system stays intact for the non-credible loss of the other interconnector. As a consequence, flows over the new interconnectors are limited so that, should the existing Heywood interconnector fail, the new interconnector would remain in service and vice versa. This reduces the likelihood of South Australia experiencing supply disruptions due to major one-off events such as a major storm.

We note that if combined interconnector transfers are not limited to allow for the non-credible loss of an interconnector then the flows over the new interconnector would be greater than assumed in the market modelling in this PADR, with associated additional market benefits.

Finally, in the high and low scenarios we have reflected gas price assumptions that represent a wider spread of potential future outcomes, compared to those used in AEMO's core scenarios in the ISP – given the importance of gas prices to the benefits being modelled under the assessment. This addresses points that were raised in several submissions in relation to ensuring the robustness of the analysis, and concerns about the previously proposed gas price assumptions in particular.

6.3 Overview of the market benefit categories estimated using market modelling

Market modelling has been used to estimate the following market benefit categories:

- changes in fuel consumption in the NEM arising through different patterns of generation dispatch;
- changes in costs for parties, other than the RIT-T proponent (ie, changes in assumed investment in generator and grid-scale storage, as well as changes in generator fixed operating costs);
- differences in the timing of unrelated transmission investment (specifically transmission investment identified by AEMO as required for development of priority REZs);

[130] The NEM reliability standard is set by the Reliability Panel, and currently requires that unserved energy (USE) in any region cannot exceed 0.002 per cent of demand per financial year.

- changes in penalties payable under the Large scale Renewable Energy Target (LRET);
- changes in involuntary load curtailment;
- changes in voluntary load curtailment; and
- changes in network losses.

The approach we have taken to estimating each of these market benefit categories is outlined below, and discussed in greater detail in the accompanying market modelling report.

The scope of this assessment is limited to the range of benefits that flow to consumers and producers of electricity. Broader economy wide benefits that may flow from increased interconnection fall outside the scope of this assessment, and are additional to the net market benefits quantified in this report.

6.3.1 Changes in fuel consumption in the NEM and costs for other parties

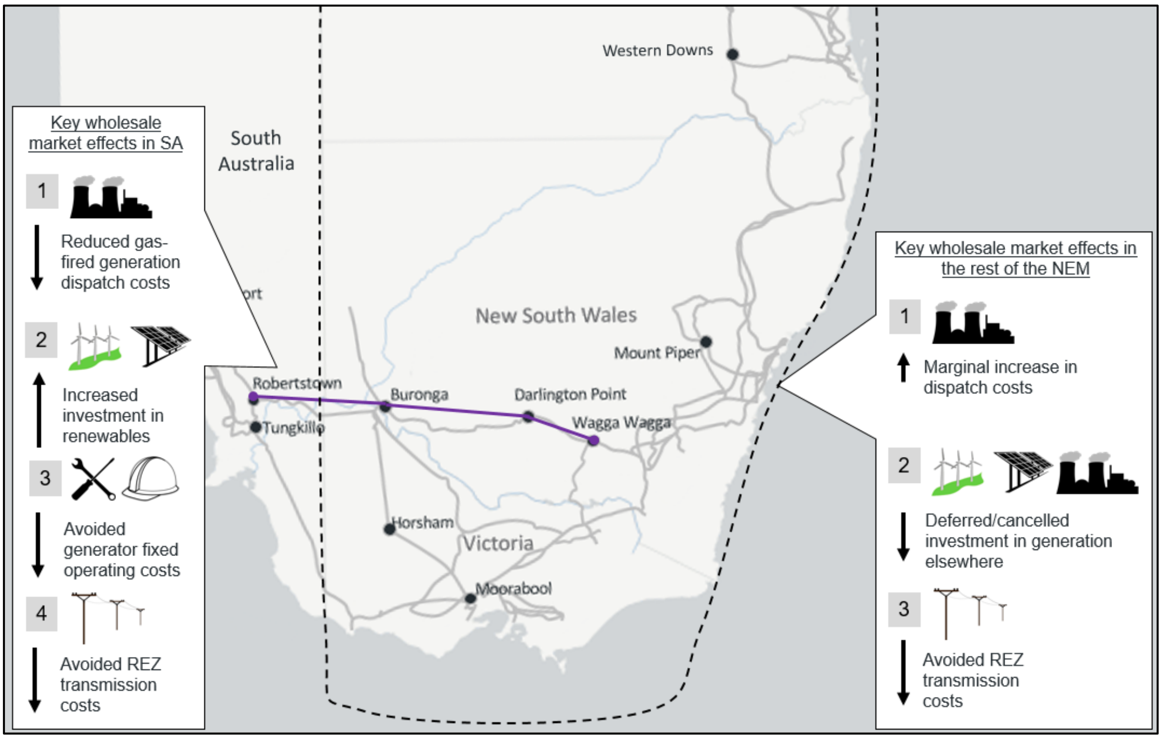
The first two categories of market benefits above are expected where credible options result in different patterns of generation dispatch and future construction (and retirement) of generators across the NEM, compared to the base case.

In particular, the primary effects of each new interconnector option are:

- reduction in the use of gas for generation dispatch in South Australia as soon as interconnection is established, due to increased options for sourcing relatively lower cost electricity from other regions;
- a reduction in generator capital and fixed operating costs, where the timing and mix of plant changes as a result of the options considered;
- a longer-term benefit for options involving new interconnection with NSW, through an increased ability to utilise generation in South Australia to avoid the higher costs associated with gas generation in NSW, as NSW black coal plant retires;
- relieving the RoCoF constraint on the operation of the existing Heywood interconnector and the cap on non-synchronous generation, thereby enabling the forced dispatch of gas generation in South Australia to be avoided.
- under the high scenario, the reduction in dispatch costs is offset by increased investment in renewable generation capacity in South Australia.

Figure 3 illustrates these effects, using Option C.3i as an example.

Figure 3 – Summary of key wholesale market effects – using Option C.3i as an example



6.3.2 Avoided transmission costs associated with Renewable Energy Zones

The third benefit category relates to the costs of intra-regional transmission investment associated with the development of REZs that could be avoided if an interconnector option was pursued.

AEMO has identified a number of REZs in various NEM jurisdictions as part of the ISP, and has highlighted the transmission augmentations that it considers would be required to develop those REZs.

The new interconnection options being considered in this RIT-T could potentially allow development of some of these REZs without the need for additional intra-regional transmission investment.

As this stage, due to the overlapping timeframes for the ISP and preparation of this PADR, we have used the results of AEMO's ISP modelling of potential REZ zones to identify the extent of transmission costs that could potentially be avoided.

However, for the PACR we intend to extend this analysis to incorporate the REZ developments into the network representation used for the market modelling, and to estimate these benefits as an outworking of the market model.

Option B1 provides an increase in the capability of QNI that may lead to a potential deferral of inter-regional transmission augmentation if pursued. Based on ISP assumptions, ElectraNet has quantified this benefit as the deferral of capital investment of $560 million from 2023 until 2040.

6.3.3 Reduction in penalties payable under the LRET

The new interconnector options also result in a minor market benefit through relieving constraints on the operation of some existing and planned wind farms, thereby avoiding penalties that are otherwise projected to be incurred under the Large-scale Renewable Energy Target (LRET).

This benefit has been captured as part of the market modelling and is not material. The introduction of the Queensland and Victorian Renewable Energy Targets as well as the increase in committed renewable generators over the last 18 months ensure the national Renewable Energy Target is met.

6.3.4 Changes in involuntary load curtailment

Increasing interconnector capacity increases generation supply availability from the rest of the NEM to meet demand in South Australia. This will provide greater reliability for South Australia by reducing the potential for supply shortages and the consequent risk of involuntary load shedding.

We have quantified the impact of changes in involuntary load shedding associated with the implementation of each credible option via the time sequential modelling component of the market modelling. Specifically, the modelling estimates the MWh of unserved energy (USE) in each trading interval over the modelling period, and then applies a Value of Customer Reliability (VCR, expressed in $/MWh) to the estimated value of avoided USE for each option.[131] We have adopted AEMO's standard assumptions for VCR for the purposes of this assessment.

This benefit has been found to be zero, given the measures that have been put in place over 2017 and 2018 to address security of supply concerns in South Australia.

6.3.5 Changes in voluntary load curtailment

Voluntary load curtailment is when customers agree to reduce their load, once pool prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances. Where the implementation of a credible option affects pool price outcomes, and in particular results in changes to the incidence of pool prices reaching higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment.

The time sequential modelling component of the market modelling incorporates voluntary load curtailment as part of its suite of dispatch options. The market benefit associated with changes in voluntary load curtailment is reflected separately in the difference in dispatch cost outcomes.

This benefit category is also found to be relatively low in practice, reflecting that the level of voluntary load curtailment currently present and over the forecast timeframe in the NEM is not material.

[131] The Value of Customer Reliability is $35,500/MWh.

6.3.6 Changes in network losses

The time sequential market modelling has taken into account the change in network losses that may be expected to occur as a result of the implementation of any of the credible options, compared with the level of network losses which would occur in the base case, for each scenario.

The benefit of changes to network losses are captured within the dispatch cost benefits of avoided fuel costs, changes in LRET penalties and changes to voluntary and involuntary load shedding.

With the addition of an option that increases inter-regional trading of power, these options will result in an increase in transmission losses across the market.

The market benefits of the change in losses have been quantified by a direct calculation of the likely MWh impact on losses in each trading interval for each year of the modelling horizon using a full nodal model, where losses are based on the line flows on each line in the NEM and the power flow at the time. Only high voltage transmission lines at voltages of 132 kV and above are considered in this assessment.

7. Scenario analysis and sensitivity testing

Several submissions to the PSCR highlighted the importance of ensuring that the outcome of this RIT-T assessment is robust to different assumptions about how the energy sector may develop in the future. Interconnector investments are long-lived assets, and it is important that the market benefits associated with these investments do not depend on a narrow view of future outcomes, given that the future is inherently uncertain.

Uncertainty is captured under the RIT-T framework through the use of scenarios, which reflect different assumptions about future market development, and other factors that are expected to affect the relative market benefits of the options being considered.

The robustness of the outcome is also investigated through the use of sensitivity analysis in relation to key input assumptions. We have identified the key factors driving the outcome of this RIT-T, and sought to identify the 'threshold value' for these factors, beyond which the outcome of the analysis would change.

Taken together, we are confident that the range of scenario analysis and sensitivity testing undertaken for the assessment in this PADR adequately addresses future uncertainty.

7.1 The RIT-T assessment considers three 'reasonable scenarios'

We have constructed three 'core' scenarios that we consider reflect a sufficiently broad range of potential outcomes across the key uncertainties that are expected to affect the future market benefits of the investment options being considered:

- a **high scenario**, intended to represent the upper end of the potential range of realistic net benefits from the options.
- a **central scenario**, which reflects the best estimate of the evolution of the market going forward, and is aligned in all material respects with AEMO's ISP neutral scenario; and
- a **low scenario**, intended to represent the lower end of the potential range of realistic net benefits associated with the various options.

The key variables that influence the net market benefits of the options are summarised in Table 6 below.

These variables do not reflect all of the future uncertainties that may affect future market benefits of the options being considered, but are expected to provide a broad enough 'envelope' of where these variables can reasonably be expected to fall.

Table 6 – Summary of scenarios considered

Variable	High scenario	Central Scenario	Low Scenario
Electricity demand (including impact from distributed energy resources)	AEMO 2018 EFI[132] strong demand forecasts plus potential SA spot load development of 345 MW	AEMO 2018 EFI Neutral demand forecasts	AEMO 2018 EFI Weak demand forecasts
Gas prices – long term	$11.87 GJ in Adelaide ($1.68/GJ higher than the AEMO ISP strong forecast)	$ 8.40/GJ (AEMO 2017 GSOO[133] Neutral forecast; $0.77 lower than AEMO ISP Neutral forecast)	$7.40/GJ ($0.62/GJ lower than the AEMO ISP weak forecast)
Emission reduction renewables policy – in addition to Renewable Energy Target (RET)	Emissions reduction around 45% from 2005 by 2030 (Federal opposition policy)	Emissions reduction around 28% from 2005 by 2030 (Federal Government policy)	No explicit emission reduction beyond current RET
Jurisdictional emissions targets	VRET 25% by 2020 and 40% by 2025 QRET 50% by 2030	VRET 25% by 2020 and 40% by 2025 QRET 50% by 2030	VRET 25% by 2020 and 40% by 2025 QRET 50% by 2030
SA inertia requirement – RoCoF limit for non-credible loss of Heywood Interconnector	1 Hz/s (International standard)	3 Hz/s (current SA Government requirement)	3 Hz/s (current SA Government requirement)
Capital costs	15% higher than central scenario	AEMO 2016 NTNDP with some updates from 2018 ISP.	15% lower than central scenario

Note that variables shown are those that have the greatest influence on the net benefits of new interconnection

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132 AEMO National Electricity Forecasting Insights March 2018.

133 AEMO Gas Statement of Opportunities December 2017, which drew on the gas price forecasts contained in the 2016 National Gas Forecasting Report. ElectraNet notes that this gas price is below the central gas price assumption of $9.17/GJ adopted by AEMO in the ISP, and therefore represents a conservative assumption that can be expected to lower market benefits overall.

We have drawn on the 2018 ISP inputs developed by AEMO where these are expected to have a material impact on the assessment, and in particular on the slow growth, neutral and high growth scenarios. However, in order to provide a broad enough range of assumptions for the purposes of testing the robustness of the RIT-T outcome, some divergence from the ISP scenarios has been applied.

In relation to future demand, we have included in the 'high' scenario additional increases in demand associated with potential future loads in South Australia, reflecting the development of new mining projects on the Eyre Peninsula.

As outlined in section 4.5.1, we received a number of submission to the PSCR that commented on the future gas price range presented at the PSCR stage. In response to these submissions, we have widened the assumed high and lower forecasts for gas prices in our assessment, compared with those adopted by AEMO for the ISP. In particular:

- the 'high' scenario includes a gas price assumption of $11.87/GJ, which is higher than the $10.19/GJ assumed by AEMO in its 'fast change' ISP scenario; and
- the 'low' scenario reflects a gas price of $7.40/GJ (based on independent advice provided by EnergyQuest), that is below the $8.02/GJ assumed by AEMO in its 'slow change' ISP scenario – it is, however, above the $5.89/GJ assumptions adopted in the more extreme 'increased role for gas' scenario in the ISP.

We have captured federal emissions reduction targets in the RIT-T market modelling through constraining aggregate dispatch when projecting capacity expansion such that emissions from the market are below the target level.

We have assumed outcomes consistent with the jurisdictional emissions targets in Victoria and Queensland, in all scenarios, in line with the ISP assumptions.

Recognising the uncertainty associated with emissions reductions to be achieved under the National Energy Guarantee, we have considered scenarios without an emissions reduction target, with a target in line with COP21 commitments and with a more ambitious 45 per cent emissions reduction by 2030. We note these assumptions are not fully aligned with the ISP assumptions at this stage, due to the overlapping timing of the analysis, but do not expect this divergence to materially impact the RIT-T assessment.

We intend to update these assumptions to align with those in the ISP in the PACR, unless we consider that adopting a wider range of assumptions is relevant in order to test the robustness of the analysis, in light of stakeholder feedback.

The final variable tested in the scenarios is a tightening of the current 3 Hz/s inertia requirement that currently applies in South Australia. The high scenario reflects an assumption that the inertia constraint is tightened to 1 Hz/s, which reflects international standards, in order to assess the potential impact that such a change could have on the outcome of the RIT-T assessment.

7.2 Weighting of the reasonable scenarios

We have applied the following weights to the three scenarios, in order to derive the weighted net market benefit under the RIT-T.

Table 7 – Assumed weights applied to each reasonable scenario

Low scenario	Central scenario	High scenario
25%	50%	25%

The low and high scenarios represent a less likely combination of assumptions occurring simultaneously across a range of variables, designed to maximise and minimise net market benefits respectively, whereas the central set of assumptions can be considered closer to the outcomes that are more likely to occur.

As a consequence, ElectraNet has applied a higher weighting to the Central scenario, than to either of the low or high scenarios.

While the above probabilities have been applied to weight the estimated market benefits and identify the preferred option across scenarios (illustrated in section 9.3), we have also carefully considered the results in each scenario.

We have also tested the robustness of the selection of the preferred option to the underlying scenario weightings. The sensitivity of the results to the underlying weightings applied to each scenario are presented in section 9.5.

The conclusions of this RIT-T are independent on the scenario weightings adopted with the preferred option being the highest ranked option across all credible scenarios.

7.3 Sensitivity analysis

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

- an assessment of the impact of assuming additional mining load in SA, a tighter RoCoF constraint, or a higher emission reduction target on the market benefits achieved under the central scenario – this assessment has been used to identify the key factors driving the very high market benefits associated with the high scenario, by considering each of the variables one at a time;
- differences in the assumed retirement dates for gas generation in South Australia, with benefits expected to be negatively correlated to the level of retirements;
- an assessment of the impact of gas prices *lower* than the $7.40/GJ ‘low scenario’ assumption on net market benefits;
- the outcome of the coincident Victorian RIT-T being undertaken by AEMO;

- the impact of an outage of the Heywood interconnector being classified as a ‘protected event’ by AEMO in future, under the recent AEMC rule change provisions regarding managing the rate of change power system frequency and managing power system fault levels. and

- other general sensitivities, ie, discount rates, capital cost estimates.

The results of the sensitivity tests are discussion in section 9.5.

8. Other assumptions relevant to the RIT-T assessment

This section provides a description of general modelling parameters adopted for the cost benefit analysis and then outlines market benefit categories not considered material for this RIT-T.

8.1 General modelling parameters adopted

8.1.1 Assessment period

The RIT-T analysis has been undertaken over a 21-year period, from 2019 to 2040.

A 21-year period takes into account the size, complexity and expected life of the relevant credible options to provide a reasonable indication of the expected market benefits and costs of the credible options considered.

Consistent with the AER RIT-T Application Guidelines, we consider that by the end of the modelling period, the network will be in a 'similar state' in relation to needing to meet a similar identified need to where it is at the time of this investment.[134]

While the capital components of the credible options have asset lives greater than 21 years, the modelling includes a terminal value to reflect the remaining asset life.[135] This ensures that the capital cost of long-lived options is appropriately captured in the 21-year assessment period.

8.1.2 Commercial discount rates applied

A commercial discount rate is applied to calculate the NPV of costs and benefits of credible options.[136]

We have adopted a real, pre-tax discount rate of 6 per cent as the central assumption for the NPV analysis presented in this PADR.

The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We have tested the sensitivity of the results to a lower bound discount rate of 3.8 per cent, and an upper bound discount rate of 8.5 per cent.

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[134] AER, *Final Regulatory Investment Test for Transmission Application Guidelines*, June 2010, version 1, p 41.

[135] The terminal value is determined as the residual value of the investments made after allowing for linear depreciation of the assets from the first year of commissioning until the last year of the horizon. The terminal value is further discounted based on the discount rate.

[136] AER, *Final | Regulatory investment test for transmission*, 29 June 2010, paragraph 2.

8.2 Classes of market benefit not expected to be material

The NER requires that all RIT-T categories of market benefit are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific category (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option.[137]

At the PSCR stage, we considered that all of the categories of market benefit identified in the RIT-T had the potential to be material for this RIT-T assessment. Since publication of the PSCR, our further assessment has highlighted that several categories of market benefit are either unlikely to affect the ranking of the credible options for this RIT-T analysis, or would represent a disproportionate level of analysis.

The reasons for these conclusions are set out in the table below in relation to each of the relevant categories of market benefit.

Table 8 – Market benefit categories under the RIT-T not expected to be material

Market benefits	Reason for excluding from this RIT-T
Changes in ancillary services costs	The cost of Frequency Control Ancillary Services (FCAS) may rise as a result of increased wind and solar generation associated with the interconnector options. However, the cost of frequency control services is not likely to be material in the selection of the preferred option. FCAS costs are typically less than 1 per cent of the total electricity market costs. Whilst recent prices in South Australia have been higher than this historical level, investment in FCAS sources in South Australia is expected to see prices return to these historical levels. Further, the inclusion of all, or some, of the FCAS markets as part of the market modelling under the RIT-T would lead to a substantial increase in the complexity and cost of the RIT-T assessment. Such increased complexity is not warranted given that changes in FCAS costs will not have a role in determining the preferred option – in particular, all interconnector options should reduce local FCAS to close to zero. Further, there is no expected change to the costs of Network Control Ancillary Services (NCAS) and System Restart Ancillary Services (SRAS) as a result of the options being considered. These costs are therefore not material to the outcome of the RIT-T assessment.
Competition benefits	All new interconnector options allow significantly higher transfer capacity, which opens up the market for more competition. However, we consider that competition benefits arising from the options considered can be expected to be similar in magnitude, and so are unlikely to affect the ranking of the options under this RIT-T.
Option value	We do not consider that there is materially more (or less) option value between the credible options investigated. Therefore, we have not applied real option valuation techniques to explicitly model any 'option value' because doing so is a computationally intensive task that is unlikely to have a material impact on the relative ranking of options, or the sign of the net benefits.

[137] NER clause 5.16.1(c)(6). Under NER clause 5.16.4(b)(6)(iii), the PSCR should set out the classes of market benefit that the NSP considers are not likely to be material for a particular RIT-T assessment.

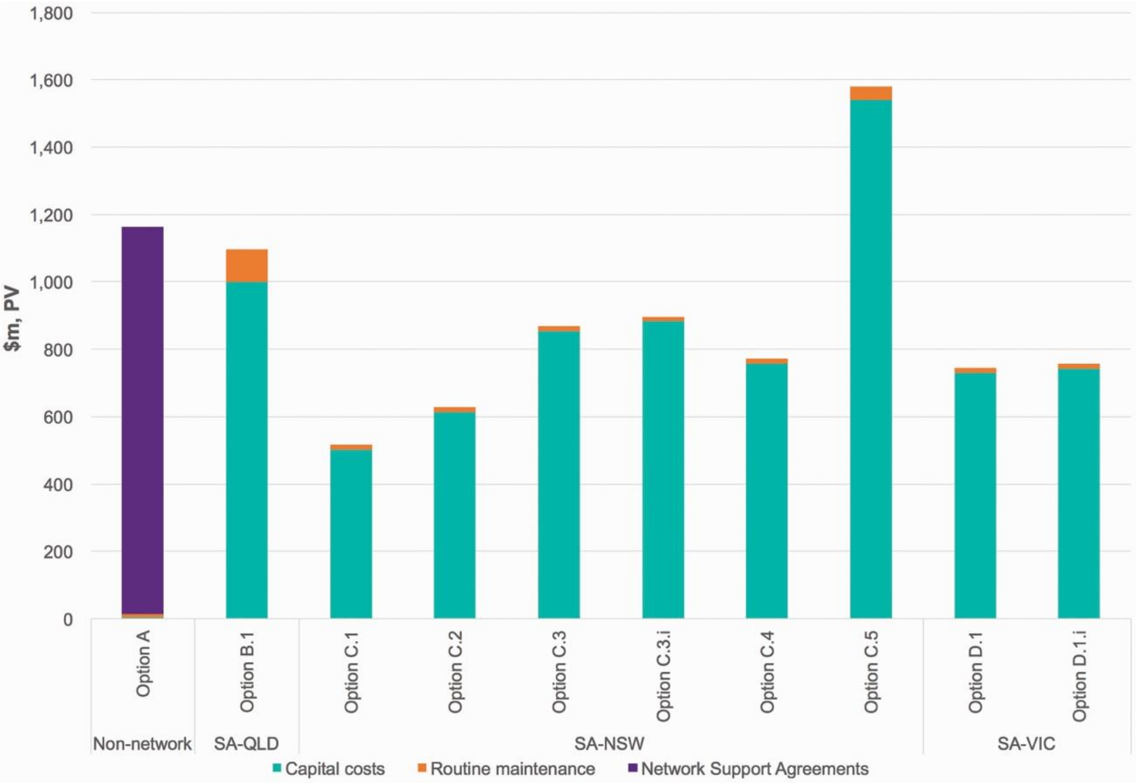
9. Net present value results

This section outlines the results of the economic assessment undertaken.

9.1 Quantification of costs for each credible option

Figure 4 shows the estimates of the total NPV costs for each option. The NPV costs differ from the capital cost estimates provided in Table 4. For the NPV estimate the upfront capital costs are partially offset by the residual value of the asset at the end of the modelling period, ie, the terminal values.

Figure 4 – NPV of costs for each option



The capital costs associated with each interconnector option are largely driven by the line length required, the interconnector capacity and whether the line is HVDC or HVAC.

Correspondingly, Options C5 and Option B1 have the highest estimated costs due to the large line length required to connect South Australia to Eastern New South Wales and Queensland respectively, and in the case of Option C5, due to its 500 kV voltage level. The interconnector options to Victoria and the 275 kV options to New South Wales have the lowest costs of the interconnector options, due to the relatively short line distances and lower interconnector capacity levels.

A small proportion of total costs is attributed to routine maintenance on the assets. The routine maintenance varies by option but is higher for the longer, higher-capacity options.

For the non-interconnector option, the majority of the costs incurred are due to network support agreements that would need to be entered into with market participants offering the technology specified for each component. On the whole, the non-interconnector option cost is of similar magnitude to the interconnector options, as shown in the Figure 4 above.

9.2 Quantification of gross market benefits for each credible option

Gross market benefits are the benefits arising from each option, without consideration of the costs of those options.

Figure 5 shows the *total* gross market benefits estimated for each option under the central scenario, ie, it does not delineate between categories of market benefit for each option. Under this scenario, the gross benefits are approximately equivalent across Options B1 and C3, and are slightly higher for Option C3i.

The additional interconnector capacity under Option C5 provides no additional benefit relative to the smaller capacity options to New South Wales, ie, Options C3 and C4.

Figure 5 - Gross market benefits for – central scenario

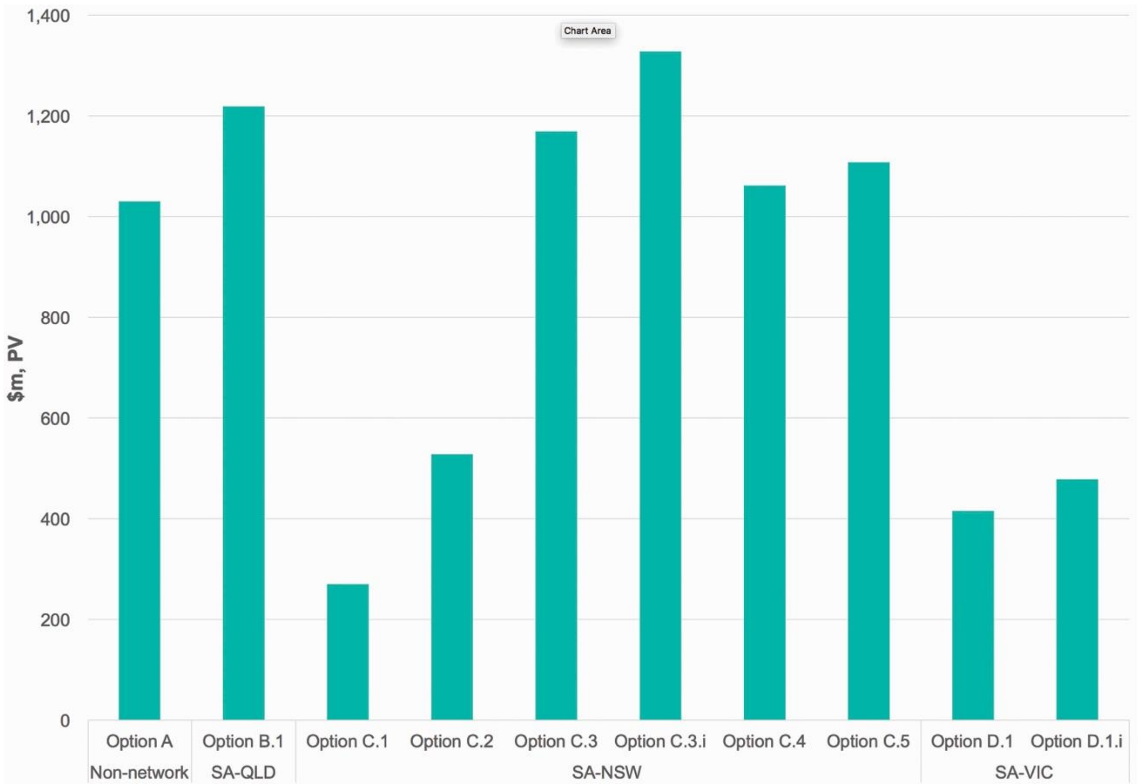


Figure 6 shows the composition of gross market benefits for each option under the central scenario.

Gross market benefits are primarily derived from avoided variable costs associated with the dispatch of generation, in particular, dispatch of gas-fired generation in South Australia. Each of the options immediately improves the ability of the South Australian system to draw on lower cost generation sources, relative to the base case, therefore reducing reliance on higher cost gas fired generation in South Australia.

In addition, new interconnector options allow more variable generation from South Australia, particularly wind, to be exported to the rest of the NEM over time and reduces curtailment of South Australian wind output. This benefit is particularly significant for the NSW interconnector options, where the retirement of black coal plant in the base case otherwise needs to be replaced with higher cost supply options.

While reducing dispatch costs, the interconnector options bring forward the retirement of some generators, in particular Torrens Island B in South Australia, which results in avoided fixed operation and maintenance costs associated with these plants.

Avoided dispatch costs are partly offset by capital expenditure brought forward for new generation capacity. This additional investment is primarily in wind generation in South Australia and Victoria which provides the energy that replaces gas fired generation.

Finally, the interconnector options reduce the costs associated with penalty payments under the existing LRET scheme due to renewable output falling short of the target level, through relieving constraints on some existing and planned windfarms. The magnitude of this benefit is zero and does not impact on the choice of option, due to the rapid uptake in committed generation across the NEM over the last 12 months and the overlapping nature of state based renewable energy policies.

The interconnection options between South Australia and NSW also provide an additional benefit through being able to avoid the intra-regional transmission costs that AEMO estimates in the ISP would otherwise be required to unlock additional renewable generation resources in the Murray River and Riverland REZs (‘avoided REZ transmissions capex’ benefit).

Similar ‘REZ benefits’ do not arise under the interconnection options between South Australia and either Queensland or Victoria. This conclusion will be tested further before publication of the PACR. ElectraNet has calculated the REZ benefit as the reduction in intra-regional network investment required to connect renewable grid scale generators. This information has been supplied by AEMO from the ISP modelling.

Figure 6 – Breakdown of gross market benefits – central scenario

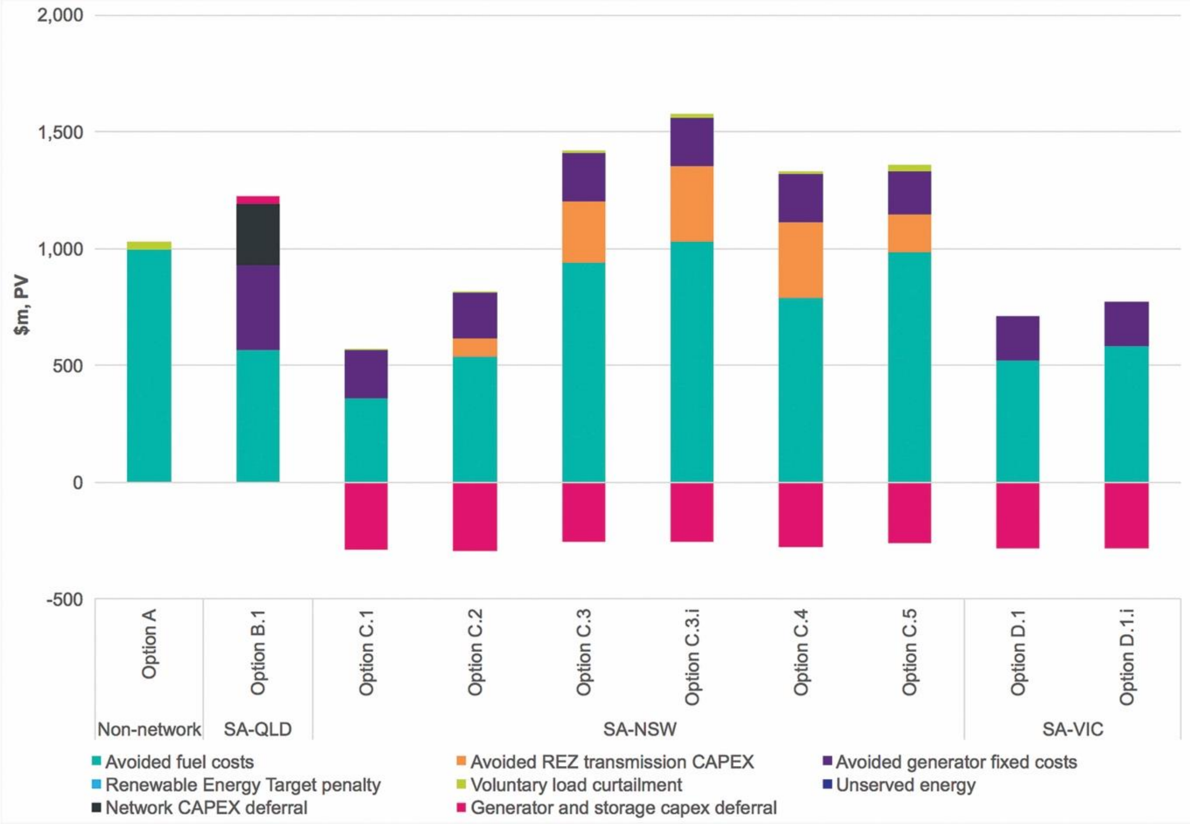


Figure 7 below presents the estimated gross benefits for Option C3.i for each year of the assessment period. While benefits from avoided fuel costs appear from as soon as the interconnector is commissioned (and last the length of the period), the avoided REZ transmission costs begin to show up from the mid-2030s (consistent with when these costs would be incurred otherwise).

There are large negative benefits (ie, costs) associated with generator and storage capital expenditure deferral late in the period due to increasing investment in higher capital, yet overall more efficient plant.

Under the high scenario, the gross market benefits are substantially higher relative to the central scenario.

Figure 7 – Breakdown of gross market benefits for Option C.3.i over time – central scenario

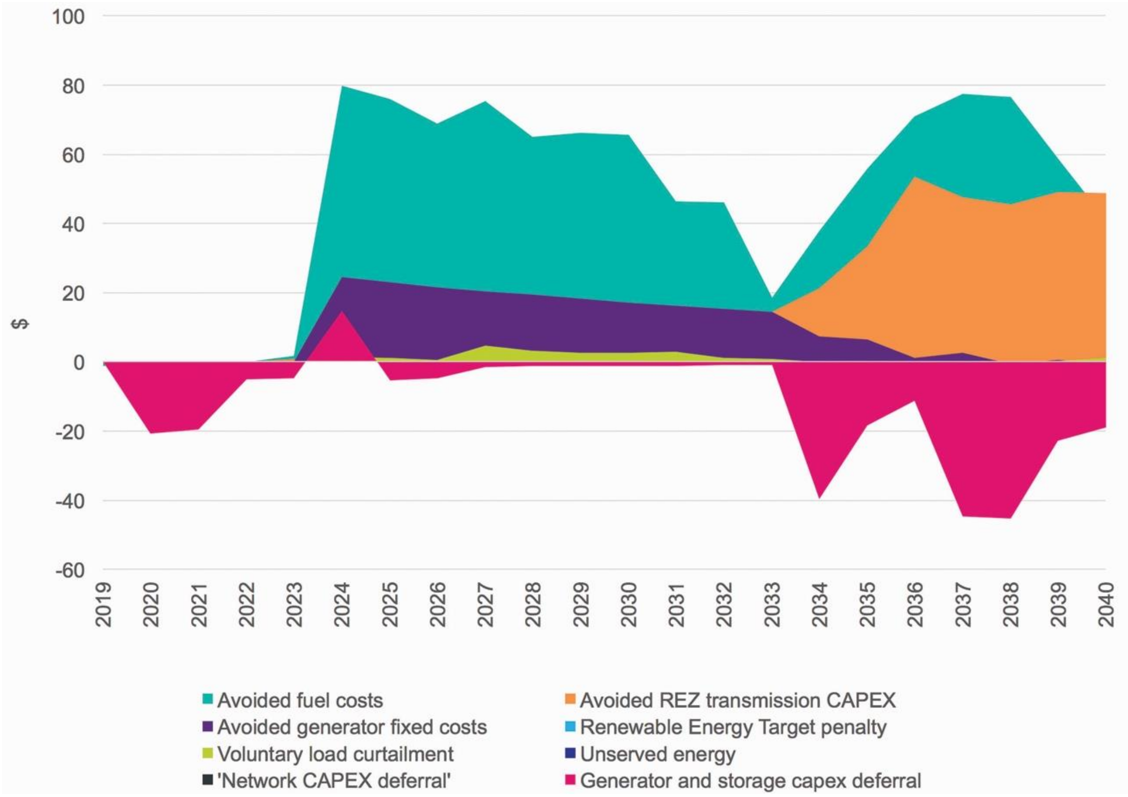


Figure 8 - Gross market benefits – high scenario

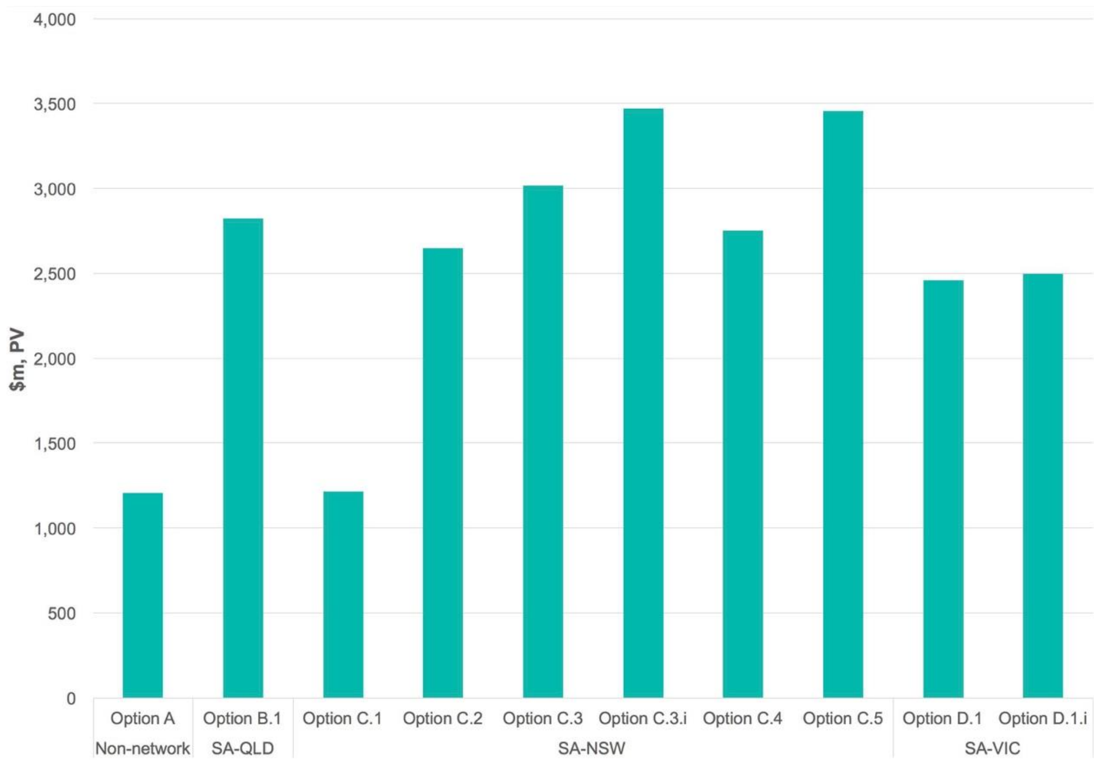


Figure 8 shows the gross market benefits for each option under the high scenario.

The higher estimated gross benefits under the high scenario are most significantly attributable to higher avoided dispatch costs. The high scenario assumes a relatively high gas price, which increases the value of avoided gas dispatch relative to the other scenarios.

This is combined with increased demand in South Australia and more stringent operating assumptions across the Heywood interconnector which drive increased gas power generation within South Australia, and stronger emission limitations which drive increased gas powered generation across the NEM.

Figure 9 shows the breakdown of gross market benefits for each option under the high scenario.

Under this scenario, additional interconnection allows more efficient allocation of capital to meet growing demand.

Figure 9 – Breakdown of gross market benefits – high scenario

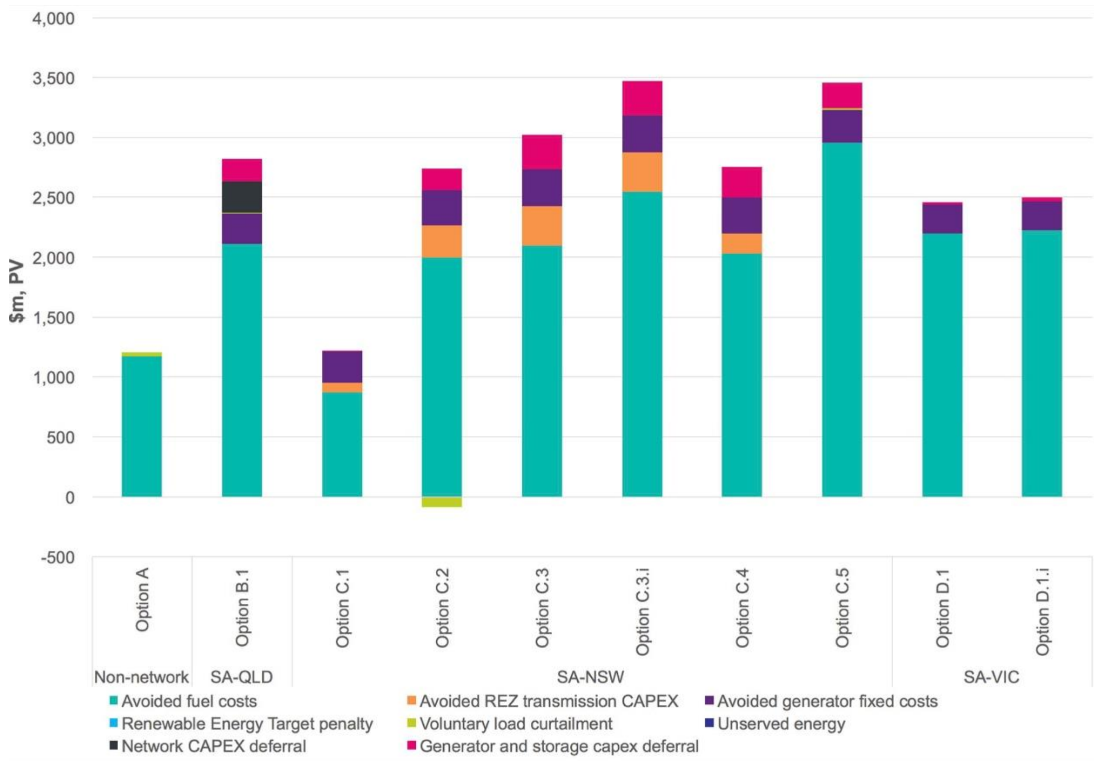
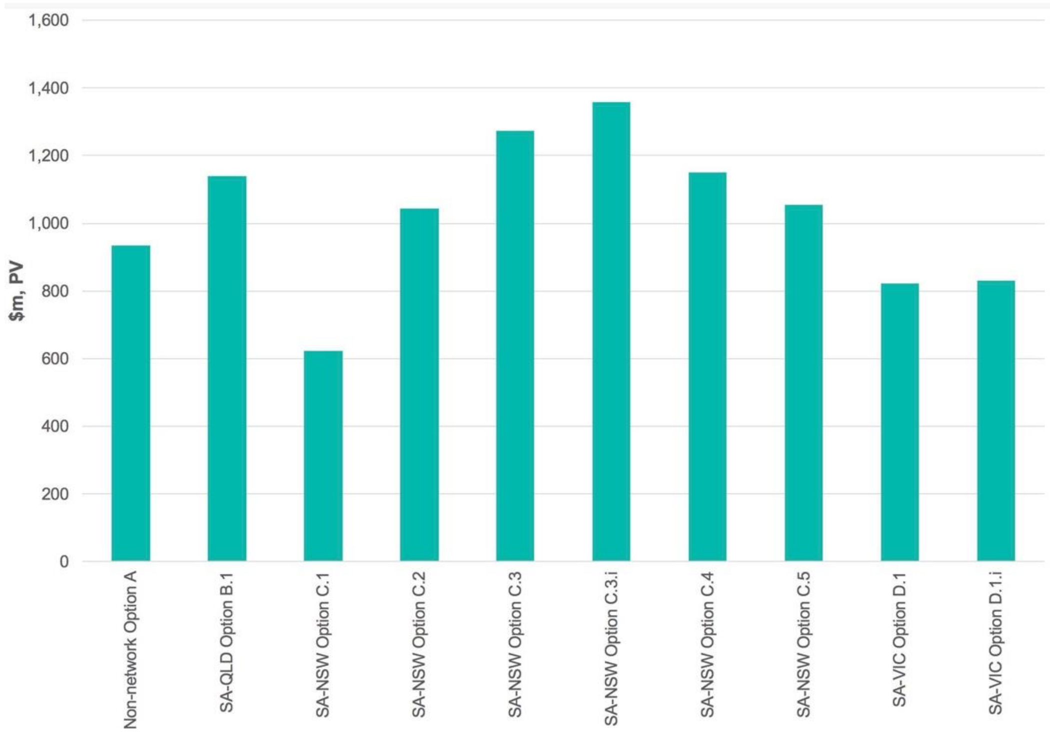


Figure 10 shows the breakdown of gross market benefits for each option under the low scenario.

Under this scenarios, gross market benefits reduce somewhat relative to the central scenario.

Figure 10 - Gross market benefits – low scenario



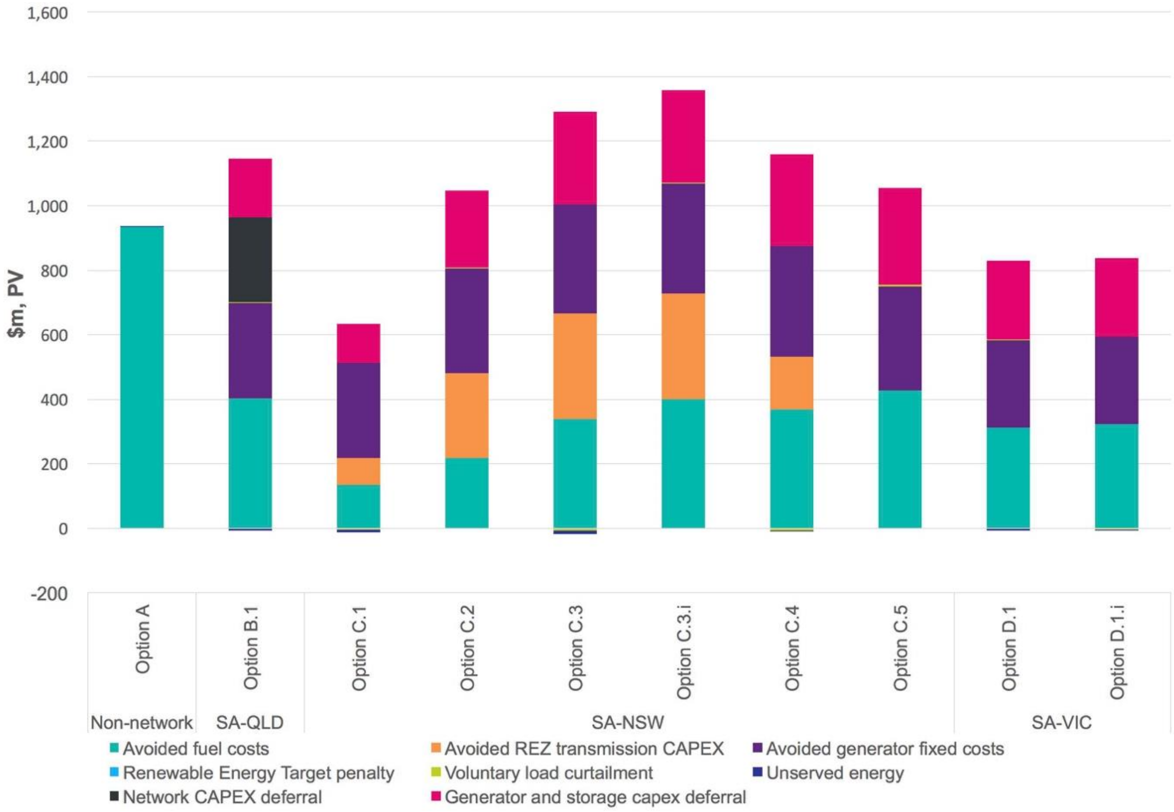
Under the low scenario, the market benefits across all interconnector options converge to between approximately $500 million and $1.3 billion in NPV terms.

As with the central scenario, a significant portion of the benefits can be attributed to the avoidance of dispatch of gas fired generation in South Australia.

However, due to the low gas price assumption in this scenario, the level of avoided dispatch costs is lower relative to the other scenarios considered.

Different to the central scenario is the increase in generator and storage deferral benefits. In the low scenario, additional interconnection allows the efficient deferral of capital decisions to result in a net saving.

Figure 11 – Breakdown of gross market benefits – low scenario



9.3 Net market benefits for each credible option

Figure 12 shows the net market benefits under all scenarios considered and the weighted scenarios outcome.

The net benefits for each option are calculated by subtracting the PV of costs, as outlined in Section 9.1 from the PV of gross market benefits, as outlined in Section 9.2.

The preferred option across all scenarios, as well as under the weighted assessment, is Option C.3i – a new 330 kV interconnector between mid-north South Australia and Wagga Wagga in NSW, via Buronga plus series compensation.

Figure 12 - Net market benefits – all scenarios

The net market benefits are markedly higher under the high scenario than for the central and low scenarios, reflecting the substantially higher gross market benefits under this scenario,

The finding that Option C.3i is the preferred option is independent of the weightings applied to the scenarios, given that it is the preferred option in all scenarios by a substantial margin, providing a 'no regrets' solution.

9.4 The magnitude of net market benefits are sensitive to gas price assumptions

The strongest driver of market benefits across all scenarios is reduced reliance on gas fired generation in South Australia.

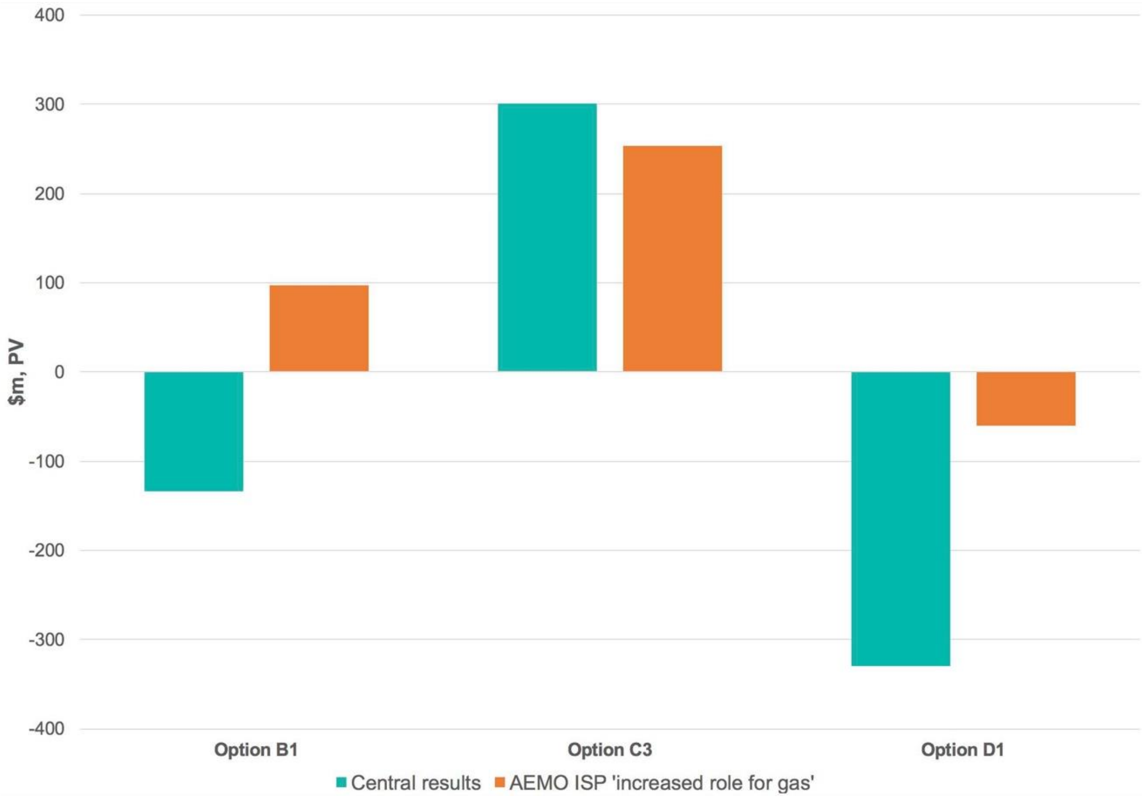
The scenario assessment indicates that although the magnitude of the results are highly sensitive to the assumed underlying gas price, the market benefits remain positive for Option C.3i across the range of gas prices considered.

We have undertaken further analysis to assess the sensitivity of the findings to the underlying gas price assumptions, and in particular the extent to which option C.3i would or would not continue to provide net market benefits under much lower gas price assumptions (all else equal).

In particular, we have tested whether interconnection options would continue to provide a positive net market benefit at the extreme low $5.89/GJ tested by AEMO, taking all other assumptions as consistent with the central scenario.

The results of this assessment are shown in the Figure 13.

Figure 13 – Net market benefits with AEMO's ISP Increased Role for Gas scenario gas prices



Even at the extreme low gas price of $5.89/GJ, interconnection between South Australia and NSW would continue to deliver a positive net market benefit, of around $0.25 billion in NPV terms over the 21 years for Option C.3 (compared with $0.40 billion under the central scenario). Option C.3i can be expected to have correspondingly higher net benefits.

9.5 Sensitivity analysis

We have undertaken a wide range of sensitivity analyses to understand the drivers of the market modelling outcomes, and have paid particular attention to ensuring the robustness of results in the high scenario, where very high market benefits have been estimated.

This assessment has shown that a new interconnector between South Australia and other jurisdictions continues to have positive net market benefits, even where future coal prices are higher than anticipated, for gas prices down to the extreme $5.89/GJ tested by AEMO, where there is a significant uptake of Virtual Power Plants (VPPs) or where gas-fired generation in South Australia is assumed to retire early in the base case.

It has also shown that the identification of an interconnector between South Australia and New South Wales as the preferred option remains robust to a range of differences in future outcomes, and in particular future gas and coal prices.

ElectraNet has considered the interaction between this RIT-T and AEMO's concurrent Western Victoria RIT-T. The identification of Option C.3i as the preferred option is not affected by the outcome of the Victorian RIT-T, as even where options being considered would reduce the cost of the Victorian interconnection options, those options would also enhance the market benefit of South Australia to NSW interconnection via Buronga.

The sensitivity analyses undertaken as part of this RIT-T assessment had a particular focus on:

- testing the robustness of the finding that the preferred route for additional interconnection is between South Australia and New South Wales;
- assessing the extent to which additional interconnection is a 'no regrets' solution that would continue to provide market benefits even where future outcomes are outside of the envelope considered in the scenario analysis; and
- understanding the drivers of the market modelling outcomes, particularly in relation to the high scenario, where very high market benefits have been estimated.

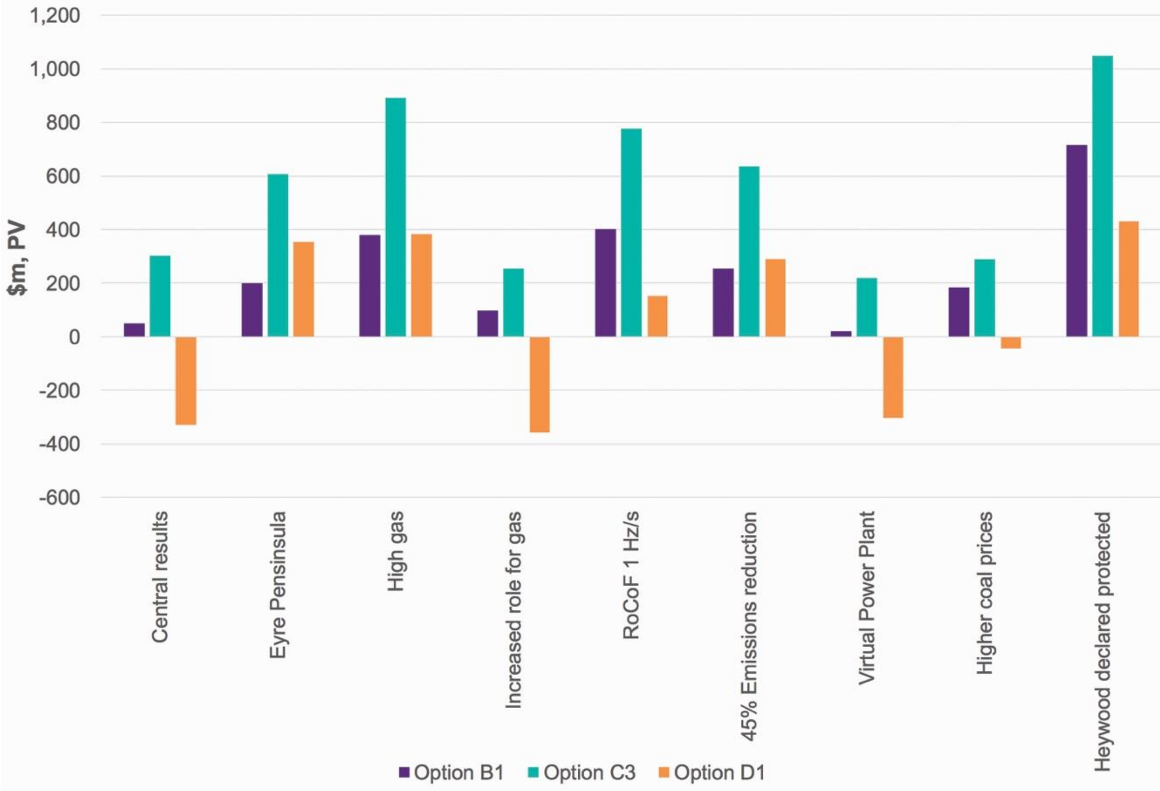
The results of this sensitivity testing in relation to ensuring the robustness of the results is shown in the figures below.

Figure 14 - Net market benefits – sensitivity to 20% increase in costs

For Figure 15, all assumptions match those used in the central scenario, with the exception of the variable being tested.

For the purposes of this analysis we have tested one option for each of the three potential interconnector routes between South Australia and Queensland, News South Wales and Victoria.

Figure 15 Sensitivity of net market benefits to key variables (central scenario)



Key assumptions for each of the variables tested are provided below:

- **Eyre Peninsula**: Adopts higher loads in South Australia (consistent with those for the high scenario) to reflect the connection of new mining load on the Eyre Peninsula.
- **High gas**: Adopts a gas price consistent with that for the high scenario, given the importance of reduced gas generation in driving the market benefit assessment.
- **Increased role for gas**: Adopts gas prices reflected in AEMO's ISP 'Increased role for gas' scenario (as shown in Figure 18).
- **RoCoF 1 Hz/s**: Adopts a more stringent limit of 1 Hz/s RoCoF for the non-credible loss of the Heywood interconnector.
- **45% emissions reduction**: Adopts the emission reduction target of the high scenario.
- **Virtual Power Plant**: 450 MW of additional distributed storage within the Adelaide metropolitan area operating as a 'Virtual Power Plant' that can be controlled by the system operator.[138] This capacity is available in the 2019-20 financial year.
- **Higher coal prices**: An increase in black coal prices of 30% for New South Wales and Queensland generators across the analysis period.

[138] The unit has 900 MWh of storage approximating the capacity of an individual Tesla Powerwall 2 unit and AEMO's ISP battery storage assumptions.

- **Heywood interconnector outage declared a protected event:** A permanent declaration by AEMO that the loss of the Heywood interconnector is a protected event. Under such a declaration, the Heywood interconnector is assumed to operate at 250 MW in the base case. When additional interconnection is assumed, the operation of Heywood remains unchanged – ie, available for 750 MW operation – as both Heywood and the new interconnector are treated as protected events by ElectraNet in the modelling. The declaration has no impact on the effect of the RoCoF constraint other than limiting the size of the contingency to 250 MW.

Figure 15 shows that Option C.3 consistently delivers the highest net market benefit for every variable tested. Again, Option C.3i can be expected to have correspondingly higher net benefits in each sensitivity test.

This assessment has shown that additional interconnection between South Australia and other jurisdictions continues to have positive market benefits, even where future coal prices are higher than anticipated, for gas prices down to the extreme $5.89/GJ tested by AEMO.

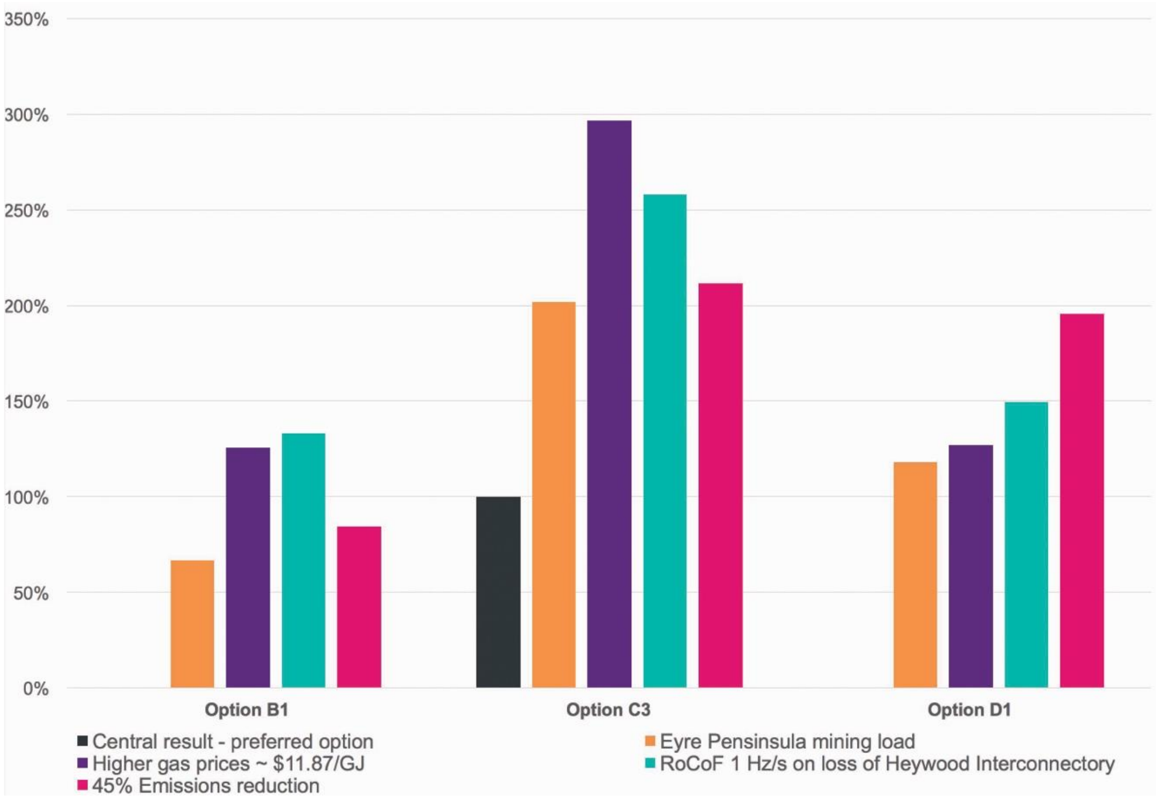
It has also shown that the identification of an interconnector between South Australia and New South Wales as the preferred option remains robust to a range of differences in future outcomes, in particular whether or not an outage of the Heywood interconnector is declared as a protected event.

Finally, we have sought to identify the key drivers of the substantial net market benefits estimated for the high scenario, by considering the impact of individual assumptions within the high scenario.

Figure 16 below presents the impact of varying just one assumption in turn in the central scenario, to match that assumed in the high scenario to identify the key variables that drive the much higher market benefits in the high scenario.

Results presented in Figure 16 are presented in relative terms to the preferred option in the central scenario. The absolute values are presented in Figure 15.

Figure 16 – Sensitivity of net market benefits to key variables (relativities)



9.5.1 Sensitivity to outcome of concurrent AEMO Western Victoria RIT-T

We have considered the interaction between this RIT-T and AEMO's concurrent Western Victoria RIT-T. The identification of Option C.3i as the preferred option is not affected by the outcome of the Victorian RIT-T.

Although some options identified within the Victorian RIT-T reduce the cost of new interconnection with Victoria in the SAET RIT-T, this reduction in cost is not sufficient to displace Option C.3i as the preferred option.

10. Conclusion

The RIT-T assessment shows that additional interconnection at 330 kV between mid-north South Australia and Wagga Wagga in NSW, via Buronga, is expected to deliver the highest net market benefit in the majority of scenarios and sensitivity tests, as well as under the weighted assessment.

Specifically, Option 3i has been found to satisfy the RIT-T as the preferred option. This option involves constructing a new 330 kV line from the mid-north region of South Australia to Wagga Wagga in New South Wales. The indicative route investigated is assumed to run approximately 920 km between Robertstown in South Australia to Buronga in New South Wales and then on to Wagga Wagga.

The key components of this option are:

- a new 330 kV double circuit line from Robertstown 330 kV to Buronga 330 kV;
- a new 330 kV double circuit line from Buronga to Darlington Point;
- a new single circuit 330 kV line from Darlington Point to Wagga Wagga;
- two new 275/330 kV transformers at Robertstown;
- a new 330/220 kV transformer and four new 330 kV phase shift transformers at Buronga;
- 50% series compensation between Robertstown and Buronga (this will be further investigated as noted before); and
- reactive plant including synchronous condensers, shunt capacitors and shunt reactors at various locations.

Capital costs for this option are estimated to be in the order of $1.5 billion across both South Australia and New South Wales. Construction is expected to require 2 years, once all necessary environmental and development approvals have been obtained, with commissioning possible between 2022 and 2024.

The new interconnector is estimated to deliver net market benefits of around $1 billion over 21 years (in present value terms)[139], including wholesale market fuel cost savings of around $100 million per annum putting downward pressure on wholesale electricity prices with flow on benefits to customer pricing. Independent modelling by ACIL Allen estimates an overall reduction in the average annual residential customer bill of up to about $30 in South Australia and $20 in New South Wales.

The overall findings from this RIT-T assessment are consistent with AEMO’s conclusion in the ISP that a new interconnector between South Australia and New South Wales is an important element of the ‘roadmap’ for the NEM and as one of its immediate priorities, that would deliver positive net market benefits as soon as it can be built.

[139] Broader benefits to the wider economic are additional to and beyond the scope of this RIT-T assessment, which is required to focus on the direct benefits to consumers and producers of electricity.

APPENDICES

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Appendix A 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.

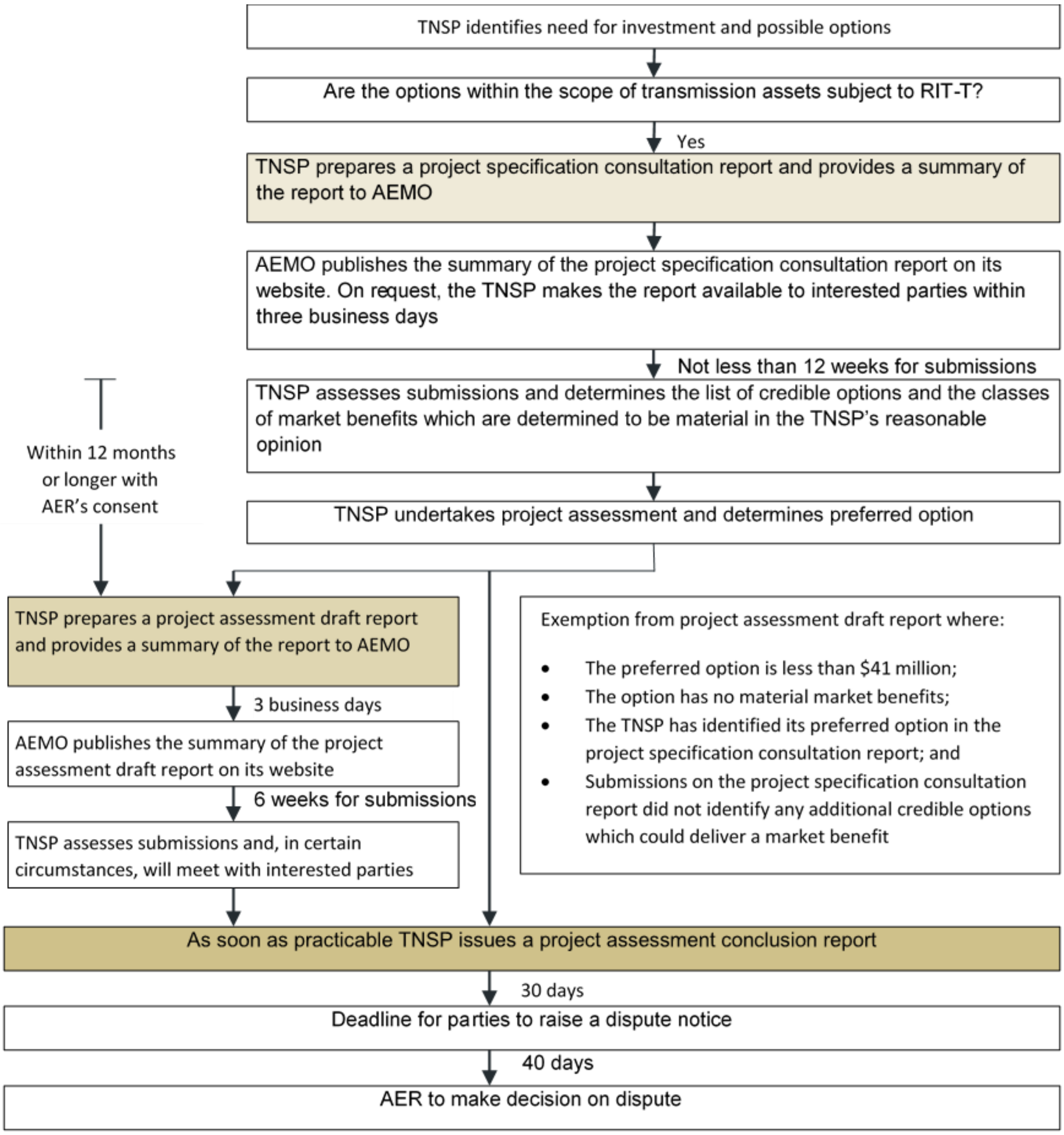
A comprehensive list of applicable regulatory instruments is provided in the Rules.

Applicable regulatory instruments	
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: 1. address the identified need; 2. is (or are) commercially and technically feasible; and 3. 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.
Market benefit	Market benefit must be: a) the present value of the benefits of a credible option calculated by: i. comparing, for each relevant reasonable scenario: A. the state of the world with the credible option in place to B. the state of the world in the base case, And ii. weighting the benefits derived in sub-paragraph (i) by the probability of each relevant reasonable scenario occurring. b) a benefit to those who consume, produce and transport electricity in the market, that is, the change in producer plus consumer surplus.
Net market benefit	Net market benefit equals the market benefit less costs.
Preferred option	The preferred option is the credible option that maximises the net economic benefit to all those who produce, consume and transport electricity in the market compared to all other credible options. Where the identified need is for reliability corrective action, a preferred option may have a negative net economic benefit (that is, a net economic cost).
Reasonable Scenario	Reasonable scenario means a set of variables or parameters that are not expected to change across each of the credible options or the base case.

Appendix B Process for implementing the RIT-T

For the purposes of applying the RIT-T, the NER establishes a three stage process: (1) the PSCR; (2) the PADR; and (3) the PACR. This process is summarised in the figure below.

Figure 17 – Key policy and regulatory developments since release of the PSCR



Source: AER, Final Regulatory investment test for transmission application guidelines, June 2010, p.43

Appendix C Supplementary information to the PADR

The following supplementary reports and information support this PADR:

- Market Modelling Report
- Market Modelling and Assumptions Data Book (spreadsheet)
- RIT-T Market Modelling, high-level review (Oakley Greenwood)
- Gas price forecast review (EnergyQuest)
- Network Technical Assumptions
- Consolidated non-interconnector option report (Entura)
- Basis of Estimate report (capital cost estimates of options)
- South Australia New South Wales Interconnector – Preliminary Projected Impact on Electricity Prices (ACIL Allen)

ElectraNet