SA ENERGY TRANSFORMATION RIT-T

Project Assessment Conclusions Report

13 February 2019

ElectraNet

Revision Record

Date	Version	Description	Author	Checked By	Approved By
13 February 2019	1.0	First Issue	Brad Harrison and HoustonKemp	ElectraNet internal review and Jurisdictional Planning Bodies	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 have applied the Regulatory Investment Test for Transmission (RIT-T)[1] to this identified need. This Project Assessment Conclusions Report (PACR) is the final formal step in the South Australia Energy Transformation (SAET) RIT-T and takes into account stakeholder feedback received during earlier stages of the RIT-T process, including consultation on a Project Assessment Draft Report (PADR) published in June 2018.

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).

Overview

This PACR confirms the draft finding that a new 330 kV interconnector between South Australia and New South Wales will deliver substantial economic benefits as soon as it can be built. The preferred option has been amended since the PADR to also include a transmission augmentation between Buronga in New South Wales and Red Cliffs in Victoria.

The analysis in this PACR and accompanying reports shows that the new interconnector will:

- deliver net market benefits of approximately $900 million over 21 years (in present value terms) including wholesale market fuel cost savings in excess of $100 million/year as soon as it is energised (primarily from avoided expensive gas-fired generation in South Australia);
- provide diverse low-cost renewable generation sources to help service New South Wales demand going forward, particularly as existing coal-fired generators retire;
- avoid substantial capital costs associated with enabling greater integration of renewables in the National Electricity Market (NEM);
- generate sufficient benefits to recover the project capital costs within nine years of completion;
- reduce annual residential bills by about $66 in South Australia and $30 in NSW, and annual small business customer bills $132 in South Australia and $71 in NSW (as estimated by ACIL Allen);
- deliver flow on economic benefits to the wider economy totalling over $6 billion across South Australian and NSW (in present value terms);
- generate over 200 regional jobs in South Australia and over 800 regional jobs in NSW during construction, and create around 250 and 700 ongoing jobs in South Australia and NSW, respectively.
- improve the ability of parties to obtain hedging contracts in South Australia and help relieve the tight liquidity in hedging markets currently.

We have undertaken extensive stakeholder engagement to ensure the robustness of the RIT-T findings and thank all parties for their valuable input to the consultation process. This engagement has significantly helped test the various options considered and ensures the robustness of the findings regarding the preferred option.

[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.

Benefits of a new interconnector between South Australia and New South Wales

Australia's energy markets are undergoing rapid change as the sector transitions to a world with lower carbon emissions and greater uptake of renewable generation and emerging technologies.

These changes have brought with them a number of challenges, including:

- a current reliance on high cost gas plant in South Australia to provide dispatchable capacity; and
- increased variability of demand and supply due to a dominance of intermittent renewable generation (both grid-scale and household PV).

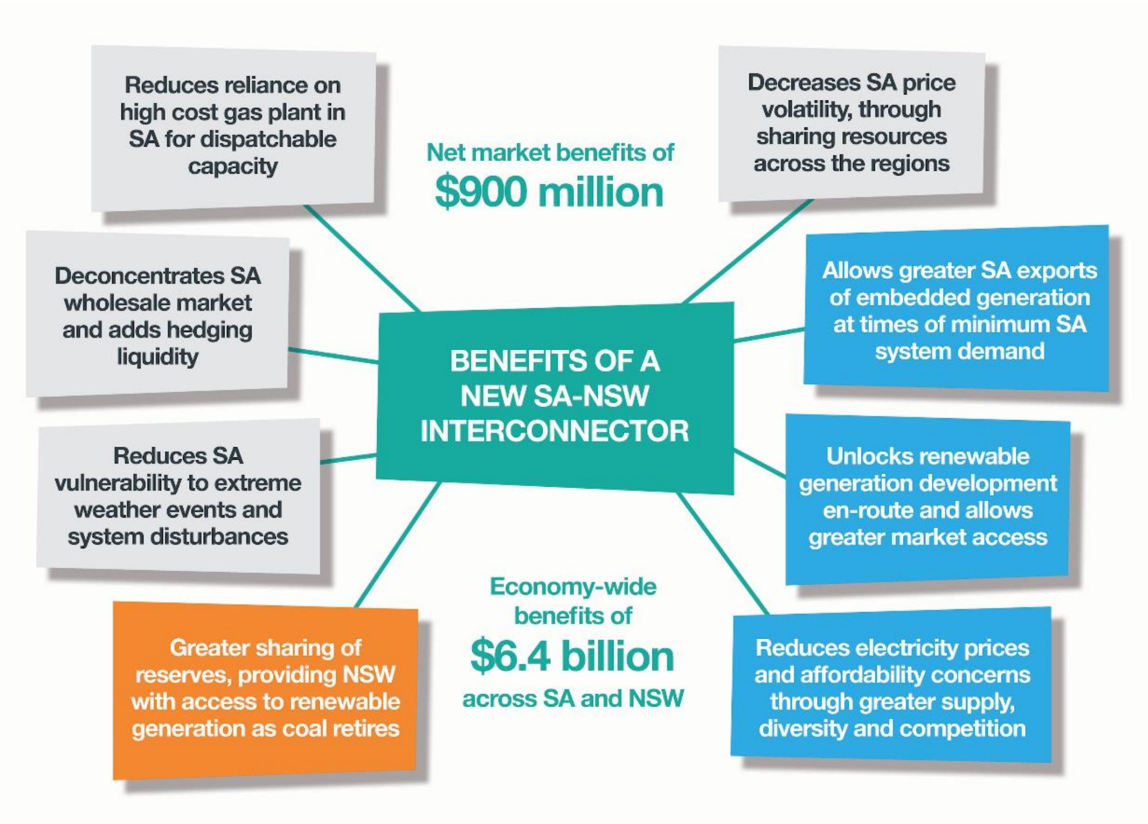
This in turn has led to high wholesale prices in South Australia and a reduction in contract market liquidity, fuelling affordability concerns for customers.

In addition, the South Australian region is seen as continuingly vulnerable to extreme weather events and system disturbances.

Going forward, the progressive retirement of around half of the New South Wales coal fleet by 2035 (or sooner) means that alternative low emission supply sources will be required to fill this gap whilst meeting Australia's carbon emissions policy commitments.

A new interconnector between South Australia and New South Wales provides a range of benefits that help meet these challenges and support this energy transition, as shown in Figure E.1.

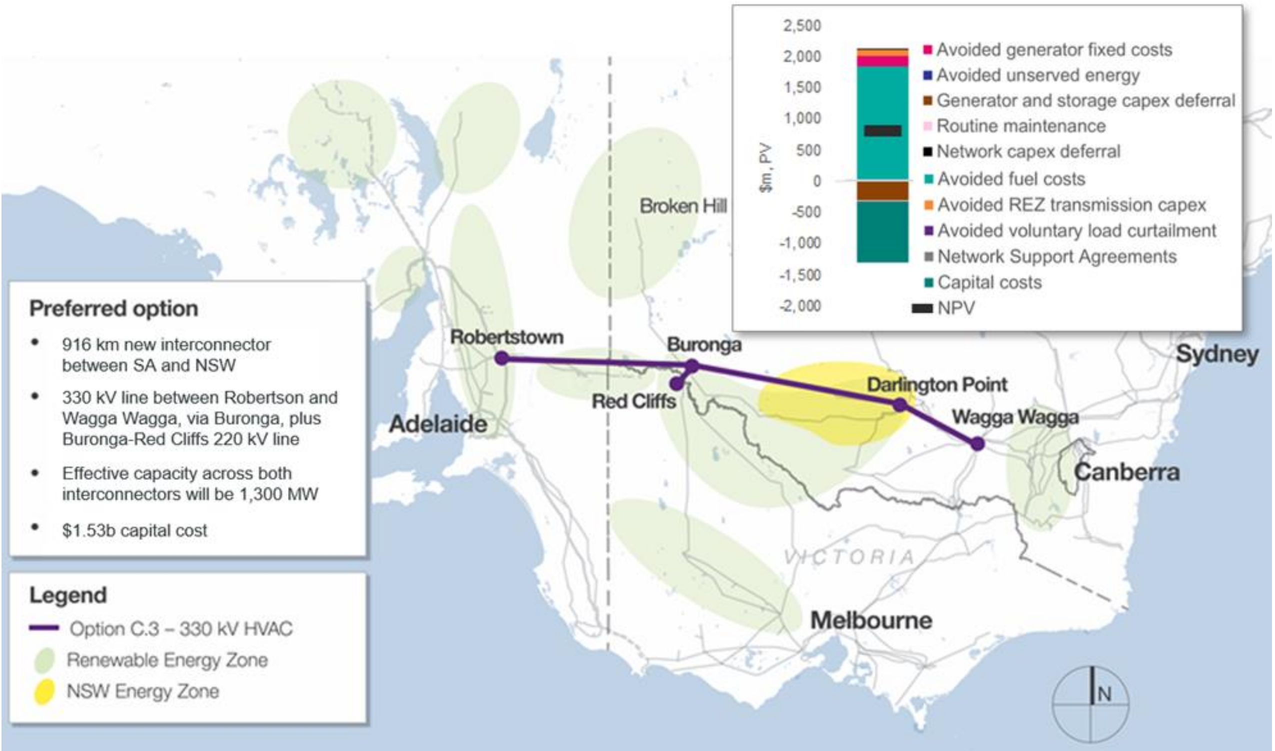
Figure E.1 Benefits of a new South Australia to New South Wales interconnector



A new high capacity interconnector between South Australia and New South Wales will 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 Robertstown in mid-north South Australia and Wagga Wagga in New South Wales, via Buronga and with an augmentation between Buronga and Red Cliffs (referred to as Option C.3), is expected to deliver the highest net market benefits and is therefore found to be the preferred option. This finding is robust across a wide range of future scenarios and sensitivity tests and is consistent with the finding of AEMO's Integrated System Plan (ISP) [2] and our earlier PADR.

Figure E.2 Preferred option for the South Australian Energy Transformation RIT-T, 'Option C.3'



The preferred option[3] is estimated to deliver net market benefits of around $900 million over 21 years (in present value terms), including wholesale market fuel cost savings in excess of $100 million per annum as soon as the interconnector is energised. These fuel cost savings are primarily driven by avoided high-cost South Australian gas generation.

The new interconnector will place downward pressure on wholesale electricity prices with flow on benefits to customer pricing. Independent modelling by ACIL Allen estimates an annual average reduction in the typical residential customer bill of about $66 in South Australia and $30 in New South Wales, and an annual average reduction for small business customers of around $132 in South Australia and $71 in New South Wales.[4]

2 AEMO published its inaugural Integrated System Plan in July 2018.

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

4 ACIL Allen, *SA-NSW Interconnector – Updated Analysis of Potential Impact on Electricity Prices and Assessment of Broader Economic Benefits*, February 2019.

The flow on effect of these reductions on the wider economy is substantial, with ACIL Allen projecting an increase in total real income over the longer term of $2.4 billion in South Australia and $4.0 billion in New South Wales (in present value terms)[5] through the construction and ongoing operation of the interconnector.[6] During construction, the project will generate over 200 regional jobs in South Australia and over 800 regional jobs in New South Wales. Based on the overall economic impact, the interconnector is projected to create 250 ongoing jobs in South Australia and 700 ongoing jobs in New South Wales.

The interconnector has an estimated delivery time of 2022 to 2024, depending on the time taken to gain environmental and other necessary approvals. However, given the benefits that will be obtained as soon as the new interconnector is in place, we are working closely with the South Australian Government and TransGrid to undertake pre-approval works to bring forward the completion timeframe of the project as much as possible. Similarly, TransGrid is working with the New South Wales government which has committed to supporting preliminary works to bring forward project delivery.

In December 2018, the South Australian and New South Wales governments signed a Memorandum of Understanding, which establishes a framework for cooperation between the two governments that seeks to expedite the delivery of the interconnector project.

The South Australian Government's underwriting of early works and the agreed framework for cooperation between governments increases the likelihood of achieving a 2022 delivery date.

AEMO's Integrated System Plan (ISP) has identified this investment as a 'Group 2' project that should proceed as soon as possible

AEMO's ISP confirms that the NEM is undergoing a fundamental transformation with large amounts of coal generation expected to close over the next 20 years to be replaced with wind and both small- and large-scale solar generation. The ISP identifies that significant investment in transmission, energy storage, flexible thermal capacity and distributed energy resources will be required to support this transformation, and in particular the diversity and intermittency of the future generation mix.

A new interconnector between South Australia and New South Wales has been confirmed by AEMO in the ISP[7] 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 of this investment has been undertaken to identify the most appropriate option that delivers the greatest net market benefits, in line with AEMO's ISP finding.

We have updated our modelling from the PADR to take into account the latest available data and information, including the AEMO ISP and its August 2018 Electricity Statement of Opportunities (ESOO).

---

5 These broader benefits to the wider economy 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.

6 This is equivalent to an increase in average real income of $1,300 per person in South Australia and $500 per person in New South Wales in present value terms.

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

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[8], the current RIT-T being undertaken by TransGrid and Powerlink investigating upgrades to the existing Queensland – New South Wales interconnection (QNI),[9] as well as the identification of priority Renewable Energy Zones (REZ) in the Riverland, Murray River and Broken Hill areas of South Australia and New South Wales.

ElectraNet received submissions from 36 parties on the earlier draft report (PADR), which have been taken into account in the PACR analysis

Our assessment has benefited from extensive stakeholder engagement. Following publication of the PADR we held separate public forums and 'deep dive' sessions in both Adelaide and Sydney, to help explain the assessment to stakeholders and to hear stakeholders' views.

We also published a number of further documents in response to requests made at the public forums, which provided additional detail on the economic and wholesale market modelling undertaken, as well as further information on the specification of the credible options assessed. In light of this further information and interaction we twice extended the submission closing date to provide stakeholders maximum opportunity to respond.

We received submissions from 36 parties in response to the PADR, and the subsequent additional documents provided. While submissions covered a range of issues, six broad topics emerged as the key themes:

- the assumptions made relating to the ongoing operation of South Australian gas-fired generators;
- feedback on the market modelling approach and assumptions, including the length of the assessment period;
- the assumptions made on the costs and specification of the non-interconnector option;
- the costs and specification of the interconnector options, in particular the HVDC options and alternative routes for a new South Australia-New South Wales interconnector;
- the potential for staging options and coordination with other transmission developments;
- specific comments on the RIT-T analysis framework.

We have taken all feedback raised in submissions into account in finalising our analysis, resulting in changes to the options being considered as well as to the RIT-T assessment itself. These changes are explained in this document, together with a comprehensive listing of all key points raised through stakeholder engagement and responses to each.

8 The PADR for this separate RIT-T was published in December 2018.

9 A PSCR for this RIT-T was released in November 2018.

Key changes to the assessment since the PADR

There have been a number of changes made to the market modelling (and in particular the input assumptions adopted), to reflect continuing changes in market and regulatory arrangements and to address comments made in response to the PADR.

These include:

- refining the options investigated, and including additional variants of the South Australia – New South Wales interconnector option that was preferred at the draft stage;
- updating input assumptions to reflect those adopted by AEMO in the ISP and the 2018 Electricity Statement of Opportunities as appropriate (whilst also investigating a number of sensitivities to test these assumptions and findings);
- undertaking a fully integrated assessment of the benefits associated with deferral of transmission investment that the ISP projects would otherwise require to unlock priority REZs (and amending the wholesale market modelling approach to accommodate this);
- applying the current South Australian Government inertia requirement (ie, 3 Hz/s) to all scenarios investigated (including the high scenario, which previously reflected a higher 1 Hz/s standard);
- updating the wholesale market modelling assumptions to reflect cycling constraints on gas generators;
- amending the scope for potential transmission investment deferral under a new South Australia - Queensland interconnector, to deferral of Stage 2 of the QNI upgrade only; and
- investigating additional sensitivities to reflect feedback in submissions in relation to key variables in the assessment, including higher than anticipated New South Wales coal prices, different assessment periods, lower costs for non-interconnector support, lower avoided transmission costs associated with connecting REZs and the interaction with the coincident Western Victoria Renewable Integration RIT-T.

In addition, notwithstanding the continuing uncertainty in relation to future emissions and reliability policies in the NEM, the modelling for this PACR continues to includes a constraint on overall emission levels that reflects Australia's COP 21 commitments in the central scenario (and tests alternative emissions reduction targets in the high and low scenarios), as well as a constraint on generation planting to ensure that the NEM reliability standard is met in all future periods.

The options investigated have been refined, and include additional variants of the South Australia-New South Wales interconnector preferred at the draft stage

We have investigated variants of four credible options to address the identified need, comprising both a predominantly 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 Table E.1 and Figure E.2.

Table E.1 – Summary of the credible options considered

Overview	Capital cost	Annual contract cost	Notional Maximum Capability (MW)[10]	
			Heywood	New interconnector
'Non-interconnector' option				
Option A – Least cost non-interconnector option in South Australia	$3m	$110m[11]	650	–
An interconnector to Queensland				
Option B – 400 kV HVDC between north South Australia and Queensland	$1.98b	–	750	700
New South Wales interconnector options				
Option C.3 – 330 kV line between Robertstown in mid-north South Australia and Wagga Wagga in NSW, via Buronga, plus Buronga-Red Cliffs 220 kV	$1.53b	–	750	800
Option C.3ii – 330 kV line between Robertstown in mid-north South Australia and Wagga Wagga in NSW, via Buronga, Red Cliffs, Kerang and Darlington Point	$1.73b	–	750	800
Option C.3iii – HVDC transmission between Robertstown in mid-north SA and Darlington Point via Buronga; HVAC line between Darlington Point and Wagga Wagga in NSW, plus Buronga-Red Cliffs 220 kV	$1.64b	–	750	800
A new interconnector to Victoria				
Option D – 275 kV line from Tungkillo in South Australia to Horsham and Ararat in Victoria	$1.15b	–	750	650

The cost of the non-interconnector option has been revised, following further analysis we conducted on the estimated costs of the battery component.

We have also reconsidered the opportunity for components of this option to provide support in the interim period before a new interconnector can be energised. However, the incremental economic benefits of this staging are not considered to be material because of:

- separate measures that are underway to address immediate system security needs in South Australia, such as the installation of synchronous condensers to meet system strength requirements that these solutions would otherwise be able to help with; and
- the South Australian Government's underwriting of early works and the agreed framework for cooperation between the South Australian and New South Wales governments that increases the likelihood of achieving a 2022 delivery date.

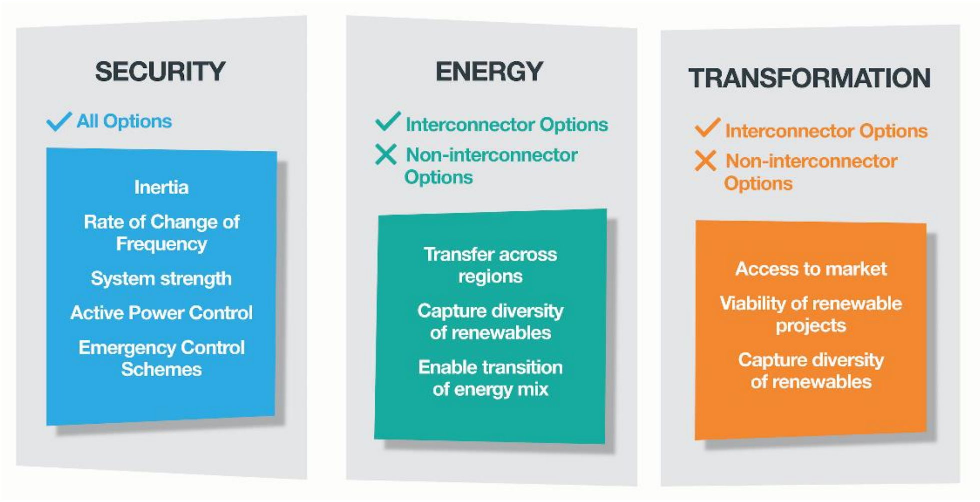
Importantly, the non-interconnector option only contributes to enhancing system security and therefore does not meet all the requirements of the identified need for this RIT-T, as illustrated in the following figure.

---

10 The notional maximum capabilities are not to be treated as additive due to network interactions. For example, the preferred option is modelled to deliver approximately 1,300 MW of combined transfer capacity.

11 This figure is for the central scenario and is the average over each year of the assessment period.

Figure E.3 – Ability of the options to contribute to meeting the identified need



The broad routes of the interconnector options remain the same as set out in the PADR, but feedback from stakeholders and additional analysis have led to elements of each option being refined, as well as revisions to the option cost estimates.

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

While a stylised straight-line representation of interconnector routes has been included in the figure above for simplicity, detailed desk-top assessments have been undertaken to identify notional routes for each option. Indicative estimated costs of land and easement acquisition have been factored into the cost estimates for the various interconnector options based on this analysis.

Additional variants of the South Australia-New South Wales interconnector option have been assessed, which include an HVDC option as well as a variant that runs via Kerang in Victoria (which was proposed in submissions).[12]

All variants of the South Australia-New South Wales interconnector now also include an augmentation between Buronga and Red Cliffs in Victoria, which separate modelling by AEMO has shown provides an incremental increase in net market benefit.[13]

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

Interconnector investments are long-lived assets (with typical economic design life of 40 years for substations and 55 years for transmission lines), and it is important that the assessment of market benefits associated with these investments is conducted over a period that adequately captures the flow of benefits over time, and that they do not depend on a narrow view of future outcomes, given that the future is inherently uncertain. It is also important that the assessment is conducted over a sufficiently long period to allow key differences in market benefits across different options to be drawn out.

Future uncertainty is captured under the RIT-T framework using scenarios, which reflect different combinations of 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 this RIT-T assessment include long-term gas prices, electricity demand, and emissions reduction policy targets (at both state and Federal levels).

Three scenarios have been considered, which cover a wide range of possible futures. These are summarised at a high-level in Table E.2. These scenarios are generally aligned with the ISP's slow change, neutral and fast change scenarios, although a wider range of future gas prices and emissions reduction policies has been assessed in the RIT-T analysis, as well as the potential for increasing load in South Australia, given the importance of these variables in driving results under this RIT-T.

Table E.2 – Summary of future scenarios considered[14]

Central Scenario	Low Scenario	High Scenario
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	Reflects a state of the world with low gas prices, low demand and no emissions reduction targets over and above the existing LRET	Reflects a state of the world with high gas prices and high demand, alongside aggressive emissions reduction targets

The results of the RIT-T assessment show that 330 kV AC interconnection options between mid-north South Australia and central and western New South Wales are expected to have a material positive net market benefit across all future scenarios (see Figure E.3).

12 Evaluation of these new variants has replaced assessment of the 'Murraylink 2', 275 kV and 500 kV capacity variants, that the PADR found provided a materially lower net market benefit.

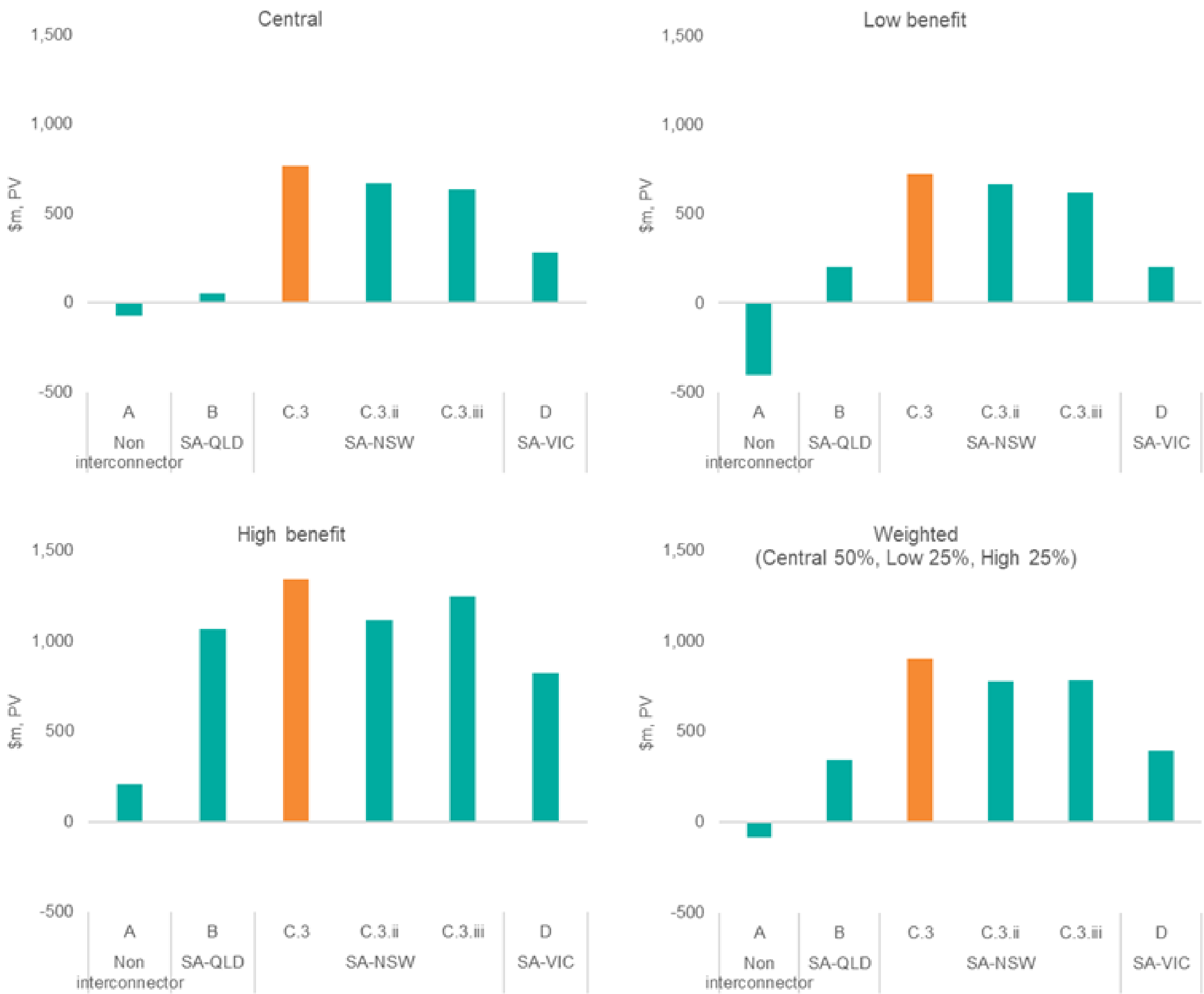
13 This modelling is presented in Appendix E to this PACR.

14 A full summary of all key assumptions in this scenario can be found in Table 8 of this PACR.

Overall, a new 330 kV interconnector between Robertstown in mid-north South Australia and Wagga Wagga in New South Wales via Buronga along with an augmentation between Buronga and Red Cliffs in Victoria (Option C.3) 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.3 has net benefits that are materially higher than the next highest ranked option in each scenario (particularly the non-New South Wales options), 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



We have also further tested the robustness of the assessment to a wide range of sensitivities, including to address points raised in submissions and to test the underlying ISP assumptions and findings. This includes higher than anticipated New South Wales coal prices, different assessment periods, lower costs for non-interconnector support, lower avoided transmission costs associated with connecting REZs and the interaction with the coincident Western Victoria Renewable Integration RIT-T.

The South Australia - New South Wales interconnector options consistently deliver greater net benefits than the other two interconnector routes investigated; i.e. to Queensland and Victoria.

The non-interconnector option is generally estimated to deliver negative net market benefits, except in the high scenario, since it does not materially lower dispatch costs or facilitate the transition to lower carbon emissions compared to the interconnector options.

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 will 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[15] 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.

We find that there remain positive net market benefits for a new South Australia to New South Wales 330 kV interconnector, for all future gas prices investigated.

New interconnection provides diverse low-cost renewable generation sources to New South Wales

The new interconnector is scheduled to be in place around the time the coal-fired Liddell power station is due to retire from the market in New South Wales, providing timely additional transfer capacity to allow for the sharing of reserves between South Australia, Victoria (on account of the Buronga to Red Cliffs augmentation) and New South Wales.

As the electricity sector transitions, coal generators are expected to continue 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 will reach the end of their technical operating lives by 2034 and 2035, leaving Mount Piper as the sole remaining coal fired generator in New South Wales.

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 future retirement of New South Wales black coal plant.

15 EnergyQuest is an Australian-based energy advisory firm, which specialises in independent energy market analysis, including on Australian oil and gas. 2017-18 dollars are presented for consistency with the PADR. Prices have been escalated to $2018-19 in the PACR analysis.

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 Western New South Wales, 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.

A new interconnector also provides benefits through enabling greater integration of renewables in the NEM without additional transmission costs

The preferred option provides a benefit through being able to avoid the intra-regional transmission costs that would otherwise be required to unlock additional renewable generation resources in the Murray River and Riverland REZs, which have been identified by AEMO in the ISP as being priority REZ areas to assist NEM transition. These benefits are derived from the higher transmission network costs required to connect these areas in the absence of a new interconnector.

The magnitude of these benefits has fallen since the PADR on account of more refined modelling of these avoided costs since the ISP was published. We also now find that these benefits commence as soon as the preferred option is energised due to the addition of the Buronga to Red Cliffs augmentation facilitating lower cost connection of renewables under the Victorian Renewable Energy Target (VRET).

While ElectraNet has modelled these benefits, recent market developments have proceeded at a faster rate than anticipated and have not been captured in this assessment. Since late 2018 for example, over 600 MW of solar generation has reached committed status west of Wagga Wagga. Including these developments in the assessment is expected to add to the estimated net market benefits of the preferred option.[16]

Importantly, the analysis also shows that the preferred option is unchanged and continues to deliver positive net benefits even without considering these benefits.

A new interconnector further enhances security of supply for South Australia

Both the interconnector and non-interconnector options contribute to improving system security, with interconnector options able to deliver greater benefits in this regard.

The benefit of relieving security of supply 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.

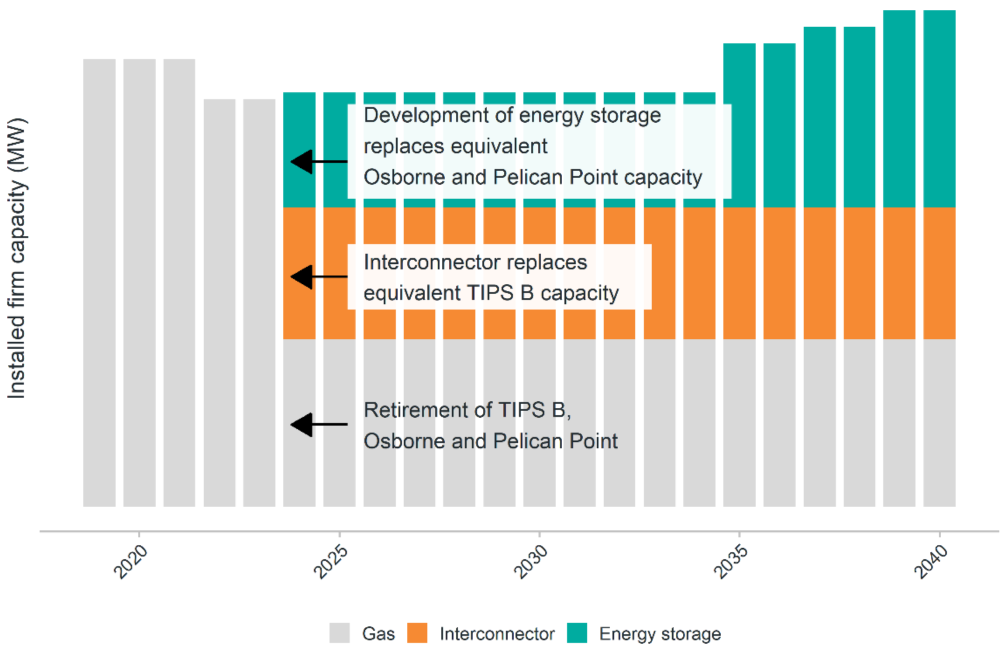
A new interconnector can be expected to increase the level of firm contractible capacity and improve market liquidity in South Australia

Our modelling shows that the South Australian gas generation capacity that retires with a new interconnector in place is more than offset by both new transfer capacity and energy storage. The figure below shows that new transfer capacity effectively replaces the capacity lost from Torrens Island B retiring, while new energy storage replaces the equivalent capacity lost from Osborne and Pelican Point retiring.

---

[16] In addition to 449 MW committed by November 2018.

Figure E.4 – Installed major gas capacity in South Australia under Option C.3



Independent analysis from energy market experts CQ Partners indicates that as market liquidity continues to decline in South Australia, a new interconnector can be expected to have a number of positive impacts on the level of forward contracts in SA and help to improve market liquidity.[17]

This is seen as the high level of market concentration in the hedge contract market in South Australia gives way to new options such as increased use of inter-regional trading, utility scale storage and embedded generation, coupled with reduced price volatility, to increase competition and place downward pressure on wholesale prices.

Next steps

This PACR represents the final stage in the RIT-T process. ElectraNet will now seek a formal determination by the AER[18] that the proposed investment satisfies the RIT-T, followed by seeking incremental revenue from the AER for this investment as a contingent project.

We will continue to work closely with the South Australian Government and TransGrid to undertake early works to bring forward the completion timeframe of the project as much as possible, so that the benefits of the project can be realised sooner.

The South Australian Government's underwriting of early works and the agreed framework for cooperation between the South Australian and New South Wales governments to expedite delivery of the project increases the likelihood of achieving a 2022 delivery date.

ElectraNet and TransGrid have launched Project EnergyConnect to deliver the new interconnector, subject to obtaining all required regulatory approvals. More information, including status updates, are available on the Project EnergyConnect website.[19]

17 CQ Partners, *SA-NSW Interconnection – Analysis of Impacts on Liquidity in SA*, February 2019.

18 Under clause 5.16.6(a) of the National Electricity Rules.

19 www.projectenergyconnect.com.au

This page is intentionally blank

Contents

FIGURES

TABLES

Glossary of Terms

Term	Description
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AEC	Australian Energy Council
AER	Australian Energy Regulator
ESOO	Electricity Statement of Opportunities
ETC	Electricity Transmission Code (South Australia)
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

This page is intentionally blank

1. Introduction

ElectraNet has been exploring and consulting on the economic benefits of new interconnector and network support options aimed at reducing the cost of providing secure and reliable electricity in South Australia, while facilitating the transition of the energy sector to low emission energy sources across the NEM.

This Project Assessment Conclusions Report (PACR) represents the final step in the application of the Regulatory Investment Test for Transmission (RIT-T)[20] to network and network support options for delivering these benefits into the future. It follows the release of the Project Assessment Draft Report (PADR) in June 2018, which presented our draft view on the preferred option at the time.

The findings of this final report are consistent with those of the draft report

This report continues to identify a new 330 kV interconnector between South Australia and New South Wales, via Buronga, as the preferred option which is expected to maximise overall net market benefits. This option now also includes a transmission augmentation between Buronga and Red Cliffs in Victoria, which independent assessment by AEMO has found to have a positive incremental net market benefit.

The new interconnector is expected to provide immediate benefits in relation to reduced dispatch costs (and prices) in South Australia, with longer term benefits accruing in New South Wales following the anticipated retirement of New South Wales coal generation.

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.

Key changes to our assessment since the PADR have focused on:

- reflecting points raised in submissions to the PADR and associated consultation with stakeholders; and
- taking into account more recent information, including AEMO's ISP and ESOO, as well as refining the estimation of the avoided transmission costs associated with connecting REZs.

1.1 We have undertaken extensive stakeholder consultation

Subsequent to the PADR, we held both public forums and 'deep dive' sessions with stakeholders, in Adelaide and Sydney, in July and August 2018 to help explain our analysis and to hear stakeholders' views.

In August 2018, we also published a number of documents in response to requests made at the public forums. These documents provided additional detail on the economic and wholesale market modelling undertaken, as well further information on the specification of the credible options assessed.

[20] The Regulatory Investment Test for Transmission (RIT-T) is the economic cost benefit test that is overseen by the AER and applies to all major network investments in the National Electricity Market.

There has been a large amount of information released as part of this RIT-T and, in recognition of this, ElectraNet twice extended the time parties had to prepare a submission.

We received submissions from 36 parties on the PADR, reflecting a range of views and interests. We have considered these submissions in the analysis presented in this report.

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).

1.2 Our final analysis takes account of the outcomes of stakeholder engagement

The assessment of options in this PACR draws on the latest information available at the time of the assessment, including inputs consulted on and adopted by AEMO in the ISP and the 2018 ESOO, as well as stakeholder feedback on the PADR.

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[21] the current RIT-T being undertaken by TransGrid and Powerlink investigating upgrades to the existing Queensland–New South Wales interconnection (QNI),[22] as well as the identification of priority Renewable Energy Zones (REZ) in the Riverland, Murray River and Broken Hill areas of South Australia and New South Wales.

This report summarises submissions to the PADR and how they have been taken into account in the final analysis, sets out the revisions to the credible options considered (in light of submissions and further analysis), presents the updated economic modelling of the costs and benefits of these options, and confirms the PADR finding that the preferred option is a new 330 kV interconnector between South Australia and New South Wales, via Buronga, with an augmentation between Buronga and Red Cliffs in Victoria.

AEMO's ISP assessment included benefits arising from the avoidance of additional transmission investment to support REZ development, which were used in our PADR assessment. A key development in the market modelling between this PACR and the earlier PADR has been to directly model these benefits within the wholesale market model used for the RIT-T assessment.

1.3 Role of this report

Consistent with the requirements in the National Electricity Rules (NER), this report:

- describes the identified need which ElectraNet is seeking to address, together with the credible options that ElectraNet considers may address this need;

---

21 The PADR for this separate RIT-T was published in December 2018.

22 A PSCR for this RIT-T was released in November 2018.

- summarises the submissions received on the PADR and accompanying consultation material;[23]
- describes the credible options considered in the assessment;
- updates the quantification of costs and classes of material market benefit for each of the credible options for developments since the PADR (including submissions received), and outlines the methodologies adopted in undertaking this quantification;
- presents the results of the Net Present Value (NPV) analysis for each credible option assessed, together with accompanying explanatory statements; and
- identifies the credible option which satisfies the RIT-T and which is therefore the preferred option for investment by ElectraNet.

Appendices to this PACR include detailed responses to points made in submissions, further information on the market modelling and AEMO's separate assessment of the incremental net market benefit associated with the Buronga-Red Cliffs component of the preferred option, and a high level breakdown of cost estimates.

We are also publishing additional detail on the results of the economic assessment undertaken and a number supporting independent reports alongside this PACR.

1.4 Next steps

This PACR represents the final stage in the RIT-T process.

ElectraNet will now undertake pre-investment activities necessary to proceed with the preferred option, including seeking a formal determination by the AER[24] that the proposed investment satisfies the RIT-T, followed by seeking incremental revenue from the AER for this investment as a contingent project.

We will continue to work closely with the South Australian Government and TransGrid to undertake early works to bring forward the completion timeframe of the project as much as possible, so that the benefits of the project can be realised sooner.

The South Australian Government has committed up to $14 million for early works and to fast-track planning and regulatory requirements.[25]

At the 21st Council of Australian Governments (COAG) Energy Council on 19 December 2018, Ministers tasked the Energy Security Board with considering how to deliver priority projects like a new South Australia to New South Wales interconnector as soon as possible.[26]

---

23 This report does not repeat the discussion of submissions to the earlier PSCR, which was presented in the earlier PADR.

24 Under clause 5.16.6(a) of the National Electricity Rules.

25 Hon Dan van Holst Pellekaan MP (Minister for Energy and Mining), Submission to the PADR, p. 1.

26 COAG Energy Council, *Meeting Communique*, 19 December 2018, p. 2.

The same day, the South Australian and New South Wales governments announced the signing of a Memorandum of Understanding (MOU), which establishes the framework for co-operation between the governments and seeks to expedite the delivery of this project.[27]

The South Australian Government's underwriting of early works and the agreed framework for cooperation between governments to expedite delivery of the project increases the likelihood of achieving a 2022 delivery date.

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

ElectraNet Pty Ltd
+61 8 8404 7966
consultation@electranet.com.au

ElectraNet and TransGrid have launched Project EnergyConnect to deliver the new interconnector, subject to obtaining all required regulatory approvals.

More information, including status updates, are available on the Project EnergyConnect website at www.projectenergyconnect.com.au.

[27] Premier of South Australia's website, available at: https://premier.sa.gov.au/news/mou-on-electricity-interconnector

2. We have undertaken extensive stakeholder engagement to ensure the robustness of the RIT-T findings

Summary points:

- ElectraNet has undertaken extensive consultation in relation to this RIT-T, including the provision of additional reports and information, and the release of detailed analysis in response to stakeholder requests.
- Stakeholder input has been elicited through submissions, public forums and deep dive sessions, as well as direct engagement.
- The options and analysis presented in this PACR have been shaped by this engagement, which has helped test the conclusions reached and ensure their robustness.

Customer and stakeholder engagement and consultation have been an important feature of this RIT-T process to ensure the identified need for investment, as well as the options to address it, were thoroughly tested.

The extent of engagement and consultation on the South Australian Energy Transformation RIT-T, which has taken over two years to complete, has exceeded that of any other RIT-T undertaken in the NEM to-date and ensures the assessment has been as thorough as possible.

This consultation builds on the significant amount of recent work and consultation undertaken by AEMO, both as part of its general development of appropriate assumptions and inputs for considering such investments (as part of the ISP and ESOO) as well as in directly considering the need for a new interconnector between South Australia and an adjoining NEM jurisdiction (as part of the ISP).

In addition to the three required RIT-T documents (ie, the PSCR, PADR and this PACR), we have released:

- 10 supplementary reports plus spreadsheet models, providing additional information on network technical assumptions, cost estimates, possible non-interconnector solution options, market modelling methodology and results and NPV analysis;
- 8 reports from independent consultants that corroborate and further investigate aspects of the analysis and points raised in submissions; and
- 2 reports assessing the expected price impacts for electricity customers in South Australia and New South Wales.

The assessment of interconnector investments is necessarily complex as such investments involve material changes in electricity flows between regions, and the analysis of future benefits requires consideration of a range of potential future outcomes.

One of the key challenges with presenting the SAET RIT-T assessment has been to make the inputs and analysis underpinning the assessment accessible to stakeholders, whilst trying to avoid overwhelming stakeholders with large volumes of material and information.

To address this challenge, we ran a number of public forums and deep dive sessions with stakeholders in Adelaide and Sydney following release of the PADR. These sessions were an effective way to present and explain our analysis and the information published, which then facilitated interrogation and discussion of the assessment with interested parties. The sessions also ensured that parties had an open forum to raise questions and queries outside of the formal submission process.

Following the PADR public forums and deep dive sessions, we released seven reports and spreadsheets in response to requests made during these sessions.

Figure 1 illustrates the extent of information released to, and consultation had with, stakeholders since the PADR was released.[28] All documents and material referenced below can be found on the ElectraNet website.[29]

A number of parties commented in submissions to the PADR that the timeframes for reviewing material released with the PADR and preparing a submission were short.

The consultation process adopted has needed to provide an appropriate balance between providing information to stakeholders and explaining that information in order to enable their active participation in the process, as well as ensuring that the assessment is completed in a timely fashion.

There has been a large amount of information released as part of this RIT-T and, in recognition of this, ElectraNet twice extended the time parties had to prepare a submission.[30]

We also note that some of the information requested by parties at the public forums had already been published as part of the PADR materials.

For example, parties requested clarity on the assumptions around the cycling of thermal units and the estimated impact on transfer capacities under each option, both of which were provided in the 'Market Modelling and Assumptions Data Book' published with the PADR.[31]

We recognise that the volume of material released can lead parties to overlook information that has been provided. We also recognise that the provision of information by itself is not always sufficient and can give rise to misinterpretation by stakeholders.

---

[28] Figure 1 shows only the consultation undertaken after the PADR was released. The RIT-T commenced in November 2016 with the release of the PSCR, together with an accompanying Market Modelling Approach and Assumptions Report and a public forum being held with interested parties in December 2016. We received submissions from 35 parties in total in response to this consultation. The PADR release was delayed on account of the many important changes to regulations and policies since the PSCR was published (see section 2 of the PADR for a description of these), including the release of the ISP.

[29] See: https://www.electranet.com.au/projects/south-australian-energy-transformation/

[30] Specifically, on 11 July 2018, at the time of releasing the Market Modelling and Assumptions Report and the ACIL Allen report on the potential price impact, we extended the submissions period by two weeks. On 17 August 2018, we further extended the deadline by another week due to the fact that we were to provide new additional material at stakeholder request on 22 August 2018.

[31] Appendix C provides a full summary of points raised in consultation on the PADR assessment (ie, both through formal submissions as well as in the public forums and deep dive sessions), as well as ElectraNet's responses to each, several of which refer to information that had been published with the PADR.

As part of the consultation process, we have therefore worked closely with stakeholders in order to ensure that they have a correct understanding of both what information has been published and how it should be interpreted.[32]

We thank all parties for their time and input to the consultation process.

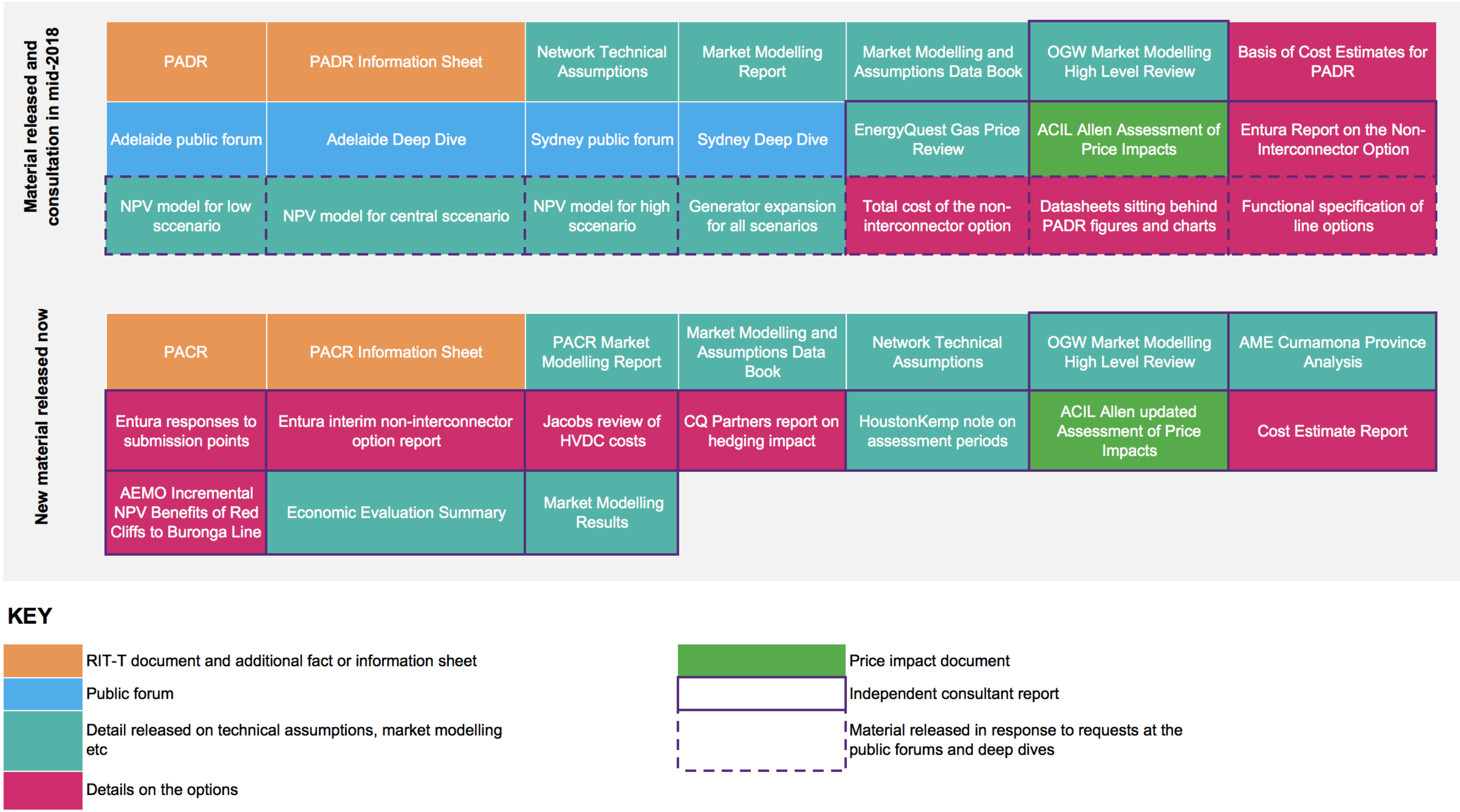
Appendix C documents all of the matters raised in submissions, as well as the associated consultation and deep dive sessions, and outlines how the analysis in this PACR has taken these comments into account.

Further detailed responses to specific submissions are provided in Appendices F and G.

Stakeholder engagement with this process has significantly helped test the various options considered and ensures the robustness of the findings regarding the preferred option.

32 For example, we engaged closely with The Energy Project to correct some misunderstandings in their interpretations of the NPV models that had been released at stakeholder request, which assisted The Energy Project in providing a supplementary submission based on a corrected understanding.

Figure 1 – The RIT-T process has been highly consultative



3. Benefits of the investment options considered

Summary points:

- The investment options considered can help overcome key challenges in the NEM, associated with the transition of the energy sector.
- Benefits are expected from lowering wholesale electricity market costs, initially in South Australia, through increasing access to supply options across regions.
- Benefits will also flow from improving access to high quality renewable resources, to meet future supply needs across regions.
- The options also enhance security of electricity supply in South Australia.

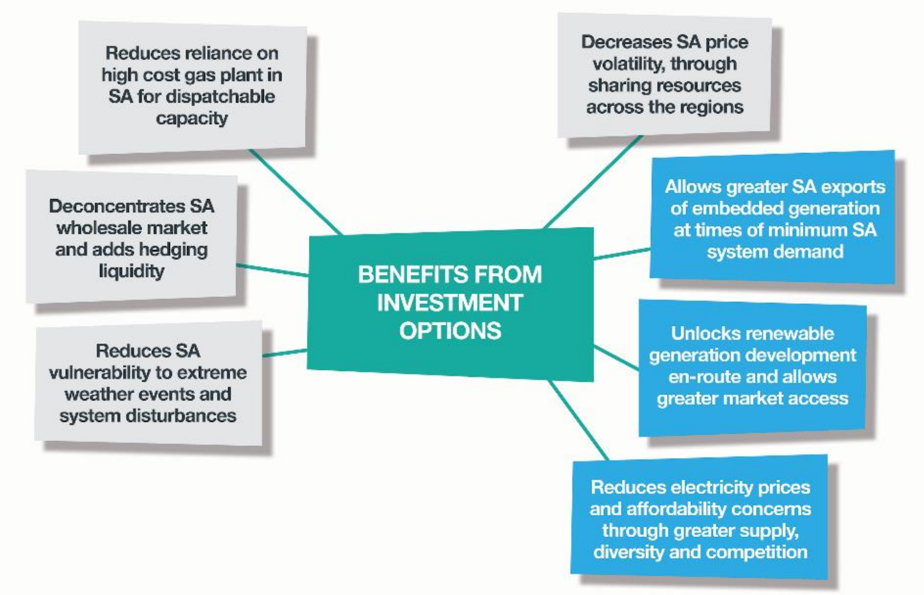
Australia's energy markets are undergoing rapid change as the sector transitions to a lower carbon emissions future and greater uptake of renewable generation and emerging technologies.

These changes bring with them a number of challenges. These include a current reliance on high cost gas plant in South Australia to provide dispatchable capacity, as well as increased variability of demand and supply due to a dominance of intermittent renewable generation (both grid-scale and rooftop solar PV). This in turn has led to high wholesale prices in South Australia and a reduction in contract market liquidity, fuelling affordability concerns for customers. In addition, the South Australian region is seen as continuingly vulnerable to extreme weather events and system disturbances.

Going forward, there is a need for large scale renewable generation development to meet future supply needs, whilst meeting Australia's policy commitments. This is particularly the case for NSW, with the progressive retirement of around half of the New South Wales coal fleet expected by 2035 (or sooner).

The interconnector investments being considered in this RIT-T provide a range of benefits that help meet these challenges and support this energy transition, as shown in Figure 2. The non-interconnector option considered could provide a sub-set of these benefits.

Figure 2 – Benefits from the investment options being considered



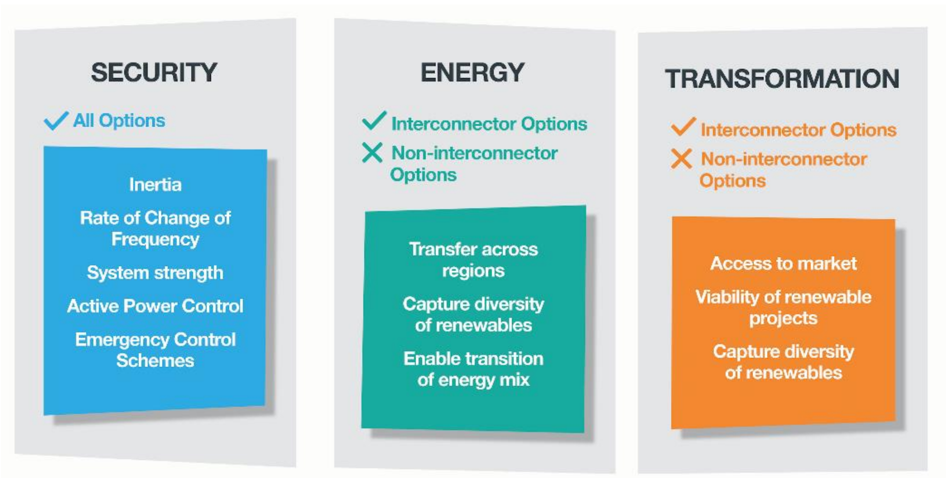
The driver for the investments being considered under this RIT-T is to create a net benefit to consumers and producers of electricity and support energy market transition through:

- lowering dispatch costs, initially in South Australia, through increasing access to supply options across regions;
- facilitating the transition to a lower carbon emissions future in the NEM and the adoption of new technologies through improving access to high quality renewable resources across all regions; and
- enhancing security of electricity supply in South Australia.

This ‘identified need’ remains consistent with that identified in the PADR.

While the interconnector options meet all three of the above components of the identified need, the non-interconnector option only contributes to enhancing system security.

Figure 3 – Ability of the options to contribute to meeting the three limbs of the identified need



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

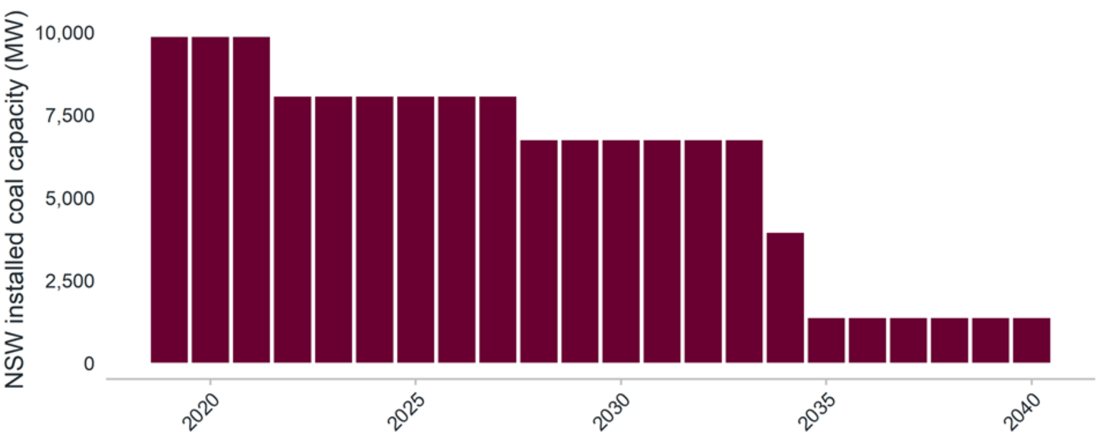
3.1 Benefits from lower dispatch costs, initially in South Australia

By augmenting power transfer capability between regions, interconnectors 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.

A new interconnector would put downward pressure on wholesale market electricity costs in South Australia, as soon as it can be built, by enabling electricity demand in South Australia to be met 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 significant high-quality renewables, provides 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 between South Australia and New South Wales, as New South Wales is forecast by AEMO to experience the greatest retirement of coal plant after 2030, and which otherwise would rely on higher cost sources of generation to fill the resulting supply gap.

Figure 4 – ISP forecast coal plant retirement in NSW, neutral scenario



The market benefits identified in this RIT-T assessment are robust to a range of longer-term outlooks in relation to future fuel prices and policy outcomes, and to different market development paths.

While not explicitly captured as a 'market benefit' under the RIT-T, it is also important to recognise that South Australia has been experiencing very high wholesale market prices. At the same time there has been increasing volatility of price in South Australia due to the growing dominance of intermittent renewable generation and variability of demand, and a lack of liquidity in the hedging contract market.

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 in South Australia would help relieve this pressure for commercial users of gas.

Allowing for a greater sharing of resources across regions will help smooth demand and supply fluctuations, and in particular reduce reliance on increasingly expensive gas generation in South Australia, reducing price volatility and trading risks.

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 and more recently grid scale solar installations.

Total renewable energy resources in South Australia exceed its combined minimum demand and export capability, putting it at the forefront of renewable penetration levels in power systems across the world.

Australia's COP21[33] 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.[34]

A new interconnector from 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.

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 emissions reduction commitments:

- further reductions in total dispatch costs, by enabling low cost renewable generation to displace higher cost conventional generation, including through the ability to harness geographic diversity across different renewable generation sources; and
- 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.

---

33 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.

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

A new interconnector also has the potential to substitute for the additional intra-regional transmission investment that AEMO is projecting in its ISP that would otherwise be required to unlock REZs to enable NEM transition.

This provides a benefit under the RIT-T framework through the avoidance or deferral of unrelated transmission investment. For example, a new SA-New South Wales interconnector would avoid the need to trigger TransGrid's South West renewables contingent project to support the development of the more than 1,000 MW of renewable generation that has only recently become committed west of Wagga Wagga in New South Wales since November 2018.

A number of parties queried the inclusion of benefits relating to avoided REZ transmission investment in submissions to the PADR and we provide responses to each point in section 4.2.2 below. The magnitude of these modelled benefits has also fallen since the PADR on account of more refined modelling of these avoided costs since the ISP was published (as outlined in section 6.3 below).

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 to address immediate system security challenges means that the options considered in this RIT-T are no longer a primary source of system security benefits for South Australia.

However, both interconnector and non-interconnector options can 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 due to system strength requirements.

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 requirement for dispatch of higher cost gas generators in South Australia.

In addition, the options considered in this PACR reduce the risk of South Australia being islanded from the remainder of the NEM and so enable a level of security not currently afforded to South Australia under the existing arrangements.

3.4 The expected sources of 'market benefit' under the RIT-T

The NER defines a number of specific 'market benefit' categories that must be considered under the RIT-T. The table below outlines how the options considered in this RIT-T are expected to deliver key market benefits as defined under the RIT-T.[35]

---

35 NER clause, 5.16.1(c)(4). Appendix D outlines how each of these categories of market benefit have been considered in this RIT-T.

Table 1 – Key 'market benefit' expected from the investment options

RIT-T 'market benefit'	How the options considered deliver this
Changes in fuel consumption arising through different patterns of generation dispatch	The options considered augment the power transfer capability between regions directly. This enables efficient sharing of generation resources, both existing and new, between regions, allowing lower cost generation to displace higher cost generation and, overall, reduce the aggregate fuel costs in the NEM. This is a key expected category of market benefit for all options considered due to need for expensive gas generation to operate in South Australia if no option is pursued, as well as the high quality of new renewable generation able to be built in South Australia. In addition, as outlined in section 3.3 above, the options considered 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. This impact is reflected in the RIT-T as a component of the fuel cost savings in South Australia, as alleviating the constraints reduces the requirement for dispatch of higher cost gas generators in South Australia.
Changes in costs for parties, other than the RIT-T proponent, due to: (A) differences in the timing of new plant; (B) differences in capital costs; and (C) differences in the operating and maintenance costs.	The options encourage more efficient investment in lower cost generation sources than would be built without these investments. An enhanced ability to export low cost power from South Australia, including significant high-quality renewables, provides 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 between South Australia and New South Wales, due to the retirement of coal plant forecast, and which otherwise would rely on higher cost sources of generation to fill the resulting supply gap. The market benefits are derived from avoided generator fixed operating costs and new generator and storage capital cost deferral (or avoidance).
Differences in the timing of expenditure	New interconnection has the potential to substitute for the additional intra-regional transmission investment that would otherwise be required to unlock REZs to enable NEM transition. This provides a market benefit through the avoidance or deferral of unrelated transmission investment. In addition, the interconnector options allow for other minor transmission expenditure to be deferred, further adding to this benefit.

4. Submissions to the PADR and additional consultation documents

Summary points:

- We received submissions from 36 parties in response to the PADR and the additional documentation provided.
- Submissions have led to revisions in modelling assumptions, and to the scope and cost of the options considered in the PACR (as well as the inclusion of two new options).
- Submissions have also led to additional sensitivity testing (including the impact of higher New South Wales coal prices, the exclusion of REZ benefits and the adoption of a shorter assessment period).
- Detailed responses to stakeholder comments in submissions and at the public forums are provided in Appendix C.

ElectraNet published the PADR in June 2018 and subsequently held public forums and 'deep dive' sessions in Adelaide and Sydney, in July and August 2018, to help explain the assessment to stakeholders and collect feedback on the analysis.

In August 2018, we published a number of additional documents in response to requests made at the public forums. These documents provided additional detail on the economic and wholesale market modelling undertaken, as well as further information on the specification of the credible options assessed.

We received submissions from 36 parties in response to the PADR and the additional documents provided. While submissions covered a range of topics, there were six broad topics that were most commented on – namely:

- the assumptions and findings made regarding the ongoing operation of South Australian gas-fired generators;
- feedback on the market modelling approach and assumptions, including the length of the assessment period;
- the viability and assumed cost and composition of the non-interconnector option;
- costs and specification of the interconnector options – in particular the HVDC options and alternative routings for a new South Australia-New South Wales interconnector;
- potential for option staging, and coordination with other investments; and specific comments on the RIT-T analysis framework.

Table 2 summarises the broad categorisation of stakeholders who made submissions; and the number of submissions with comments falling under the above categories.

Table 2 – Summary of submissions to PADR consultation papers

Submissions from	No.
Market participants	**12**
Advisory bodies/ universities	**11**
Manufacturers and other proponents	**11**
Jurisdictional planning bodies	**2**
Total submissions	**36**

Key submission topics	No.
Feedback on market modelling approach and assumptions	**11**
Operation of SA gas generators	**8**
Specific comments on RIT-T analysis framework	**7**
Comments on non-interconnector options	**7**
Comments on interconnector options	**9**
Staging and coordination of options	**6**
Note: most submissions address multiple topics	

Submissions have been taken into account appropriately in undertaking the assessment presented in this report. In particular:

- the interconnector options included in the analysis have been modified, and new option variants included, reflecting points raised in submissions and subsequent further analysis;
- the costs of the battery component of the non-interconnector option have been reduced, reflecting submission comments on alternate revenue sources;
- an interim non-interconnector option has been considered;
- additional detail in relation to the modelling approach and assumptions has been provided in a further market modelling report accompanying this PACR, to address requests for increased transparency;
- the wholesale market modelling assumptions have been updated to reflect cycling constraints on gas generators;
- the 'high scenario' has been modified to reflect the current 3 Hz/s South Australia RoCoF requirement; and
- additional sensitivities have been tested reflecting feedback in submissions, including higher than anticipated New South Wales coal prices, different assessment periods, lower costs for non-interconnector support, lower avoided transmission costs associated with connecting REZs and the interaction with the coincident Western Victoria Integration RIT-T.

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

Appendix C provides a summary of all points raised as part of consultation on the PADR, while Appendix F responds to the various matters raised by The Energy Project (and other respondents that refer to The Energy Project analysis) and Appendix G responds to points raised by ARCMesh (primarily in relation to an HVDC interconnection to Queensland).

Appendix E presents AEMO's assessment of the additional incremental benefits of the Buronga to Red Cliffs augmentation, which was commented on in a number of submissions.

4.1 Operation of South Australian gas-fired generators

Submissions raised a number of points regarding the assumed operation of South Australian gas-fired generators going forward. We summarise and respond to the key points in the three sections below.

4.1.1 Assumed operation and retirement dates for SA gas-fired generation

Several submissions raised questions relating to the assumed timing of the retirement of gas-fired plant in South Australia in the PADR modelling, and the differences with the assumptions made by AEMO in the ISP.

The observed differences in the modelling outcomes for the operation of these plant is primarily due to the assumptions regarding the minimum operation levels of South Australian gas plant, as well as the other input assumptions used (eg, heat rates, gas prices etc), at the time of the PADR.

In summary:

- the PADR, released in June 2018, mostly used the latest prevailing NTNDP input assumptions[36] (which did not assume any minimum South Australian gas plant operation levels); and
- the ISP, released in July 2018, used the 2018 ISP input assumptions (including minimum South Australian gas plant operation levels).

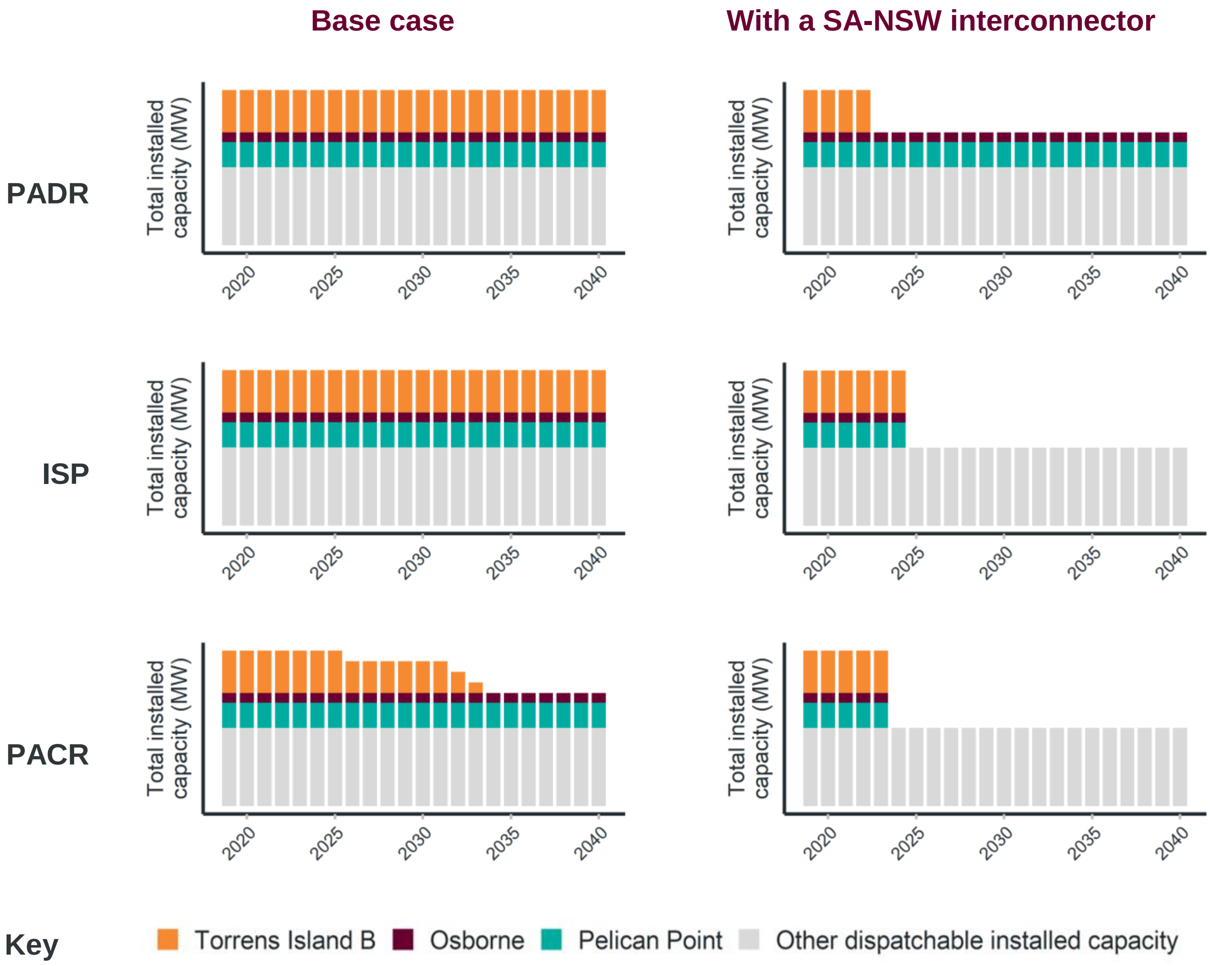
In response to submissions, the PACR now aligns all generator input assumptions with the ISP, including minimum operation of South Australian gas plant (although we have also undertaken sensitivity testing around these assumptions, as outlined below).

The figure below shows how the operation of South Australian gas-fired generators has been modelled in the PADR, ISP and this PACR.

Note this figure only highlights the modelled impact on three key generators (ie, Torrens Island B, Osborne and Pelican Point) and, even when all three are found to retire, there is still gas-fired generation operating in South Australia (eg, Barker Inlet).

[36] Full details on the sources of all inputs in the PADR can be found in the PADR Market Assumptions Report.

Figure 5 – Timing of key SA gas-fired generator retirements under the PADR, ISP and PACR



Note: the figure above shows the PADR and PACR results for Option C.3 under the central scenarios only, as well as the ISP neutral scenario.

The key difference in modelled outcome between the ISP and this PACR is that Torrens Island B is found to progressively retire under the central base case in the PACR modelling from 2026, whereas the ISP does not model retirement of Torrens Island B in the base case over the assessment period. This reflects the different suite of market modelling tools used by AEMO and ElectraNet. The PACR finding in the base case closely aligns with when Torrens Island B might be expected to begin to retire due to reaching the end of its 50-year standard technical life (which occurs in 2027).

However, consistent with the ISP, we now find that all three South Australian gas plants retire once a new interconnector is in place, albeit a year earlier than projected in the ISP due to changed assumptions since the ISP regarding when a new interconnector can be energised.

Given the various modelled outcomes for South Australian gas plants in the PADR, ISP and this PACR, and comments in submissions, we have extended our sensitivity testing for this important variable.

Specifically, the PACR investigates the effects of:

- removing the minimum operation constraints on these plants (ie, consistent with the approach taken the PADR):[37]
  - this sensitivity reduces the estimated benefits of all options as the quantum of gas generation in South Australia is lower in the base case (see Figure 23) but does not change the preferred option and is presented in section 8.5.3;
- assuming that all units of Torrens Island B retire at or before 50-years of age under the base case; and
- assuming a new interconnector has no impact on the operation of Pelican Point and Osborne (ie, they do no retire nor change their behaviour).

The last two are considered extreme sensitivity tests and have been undertaken as additional tests on the robustness of the findings of this PACR. Both find that the net market benefits of the preferred option are reduced under these extreme assumptions but are still materially positive.

In addition to the retirement profile of South Australian gas-fired plants, EnergyAustralia commented in its submission that the PADR modelling did not take into account the constraint on the cycling of gas generators.[38] In response, we have investigated this assumption further and have modified our modelling to reflect this constraint.

EnergyAustralia also queried in the Sydney ‘deep dive’ session whether the system strength cap has been modelled and if there is a synchronous generation requirement in the base case. We have a requirement for four synchronous units in South Australia in the base case. This has been included in the PACR but was not a requirement at the PADR stage.

4.1.2 Accounting for the impact on the hedging market

A number of parties queried how different options are expected to impact the hedging market and how this is captured in the assessment.

A view was expressed that the early retirement of South Australian gas generators in response to interconnector development will exacerbate the already tight liquidity in the hedging market in South Australia.

A new interconnector is expected to improve the ability of parties to obtain hedging contracts in South Australia due to the increased interlinkage with adjacent regions. Specifically, there will be a material improvement in firm interconnection between South Australia and the rest of the NEM since, following energisation, the number of AC circuits will increase from two to four.

Snowy Hydro supported the view that increased interconnection would improve liquidity in the hedging market by stating that the removal of congestion along the path between Snowy and South Australia will allow them to offer firming capacity in South Australia.[39]

---

37 For clarity, this sensitivity applies all ISP input assumptions but removes the minimum operating constraints on South Australian gas generators.

38 EnergyAustralia, pp. 1-2.

39 Snowy Hydro, p. 3.

We also received a confidential submission from a potential investor that stated that if a new interconnector proceeds, then they plan to invest to offer firming capacity in South Australia. This investor noted that these investments could only take place if supported by increased interconnection to the eastern states. In both cases, increased interconnection will lead to increases in firm supply in South Australia below $70/MWh that would not otherwise be available in South Australia.[40]

An increase in the liquidity of the hedging market improves the firmness of hedging contracts offered across regions and, in turn, the ability of South Australian retailers to obtain hedging contracts will improve. In the absence of a new interconnector, firming capacity can only be offered by existing conventional generation, or by investment in new firming capacity, which comes at a higher overall cost to the NEM.

Business SA asked for further explanation about how the uplift in the Heywood interconnector as a result of a new interconnector could be relied on by generators looking at options to hedge firm between the states.[41]

We obtained expert advice on this point. The accompanying CQ Partners report outlines how the ability to utilise both interconnectors for hedging, along with utilising settlement residue auction units and also local utility scale storage plus peaking gas generators, will assist in the ability of parties to manage spot price risk. [42]

Our modelling does not take into account impacts on the contract market directly. However, it does capture changes in the costs of dispatching generation in South Australia, which are ultimately passed on as savings to customers.

EnergyAustralia requested that the management of intra-regional constraints is demonstrated and the PACR describe the operation of the interconnector options and the existing Heywood interconnector during planned and forced outages.[43] At a high-level:

- currently, a prior network outage condition between Tungkillo (outside Adelaide) in South Australia and Sydenham (outside Melbourne) in Victoria results in the Heywood interconnector's capability being reduced to 50 MW to manage the next and worst contingency which would result in severing the AC connection between South Australia and Victoria.

- with the preferred option in place, under a prior outage condition three circuits will remain in operation connecting South Australia with the eastern states, which will provide significantly higher transfer capacity of about 850 MW during planned outages.

With the preferred option in place, the next and worst contingency would be the loss of one circuit along the path (either Heywood or the new interconnector) that would sever one path.

40 Confidential submission; and Snowy Hydro's website, available at: https://www.snowyhydro.com.au/news/shl_deals/

41 Business SA, p. 1.

42 CQ Partners, SA-NSW Interconnection – Analysis of Impacts on Liquidity in SA, p.36

43 EnergyAustralia, p. 7.

The remaining path would be fully intact and the interconnector capacity would be in a similar state as it is today. Under this prior outage, and to manage this next and worst contingency, the combined limit across the two interconnectors would be restricted to 850 MW.[44] This is a significant improvement from the 50 MW which is applied today for planned outages.

Our studies indicate that with the preferred option, the interconnectors can operate to allow about 1,300 MW of combined imports. Which of the two interconnectors is more heavily utilised is not material. If there is a loss of one of the interconnectors either when both circuits are in service or during a planned outage of one of the circuits, the other interconnector will remain connected with the operation of a Special Protection Scheme (SPS), which would trigger batteries and some limited load shedding to avoid a SA state-wide system black event, which will become extremely unlikely. With the future addition of batteries with reserved capacity in the SPS, the combined limits can be further increased.

The CQ Partners assessment of the impact on the hedging market states that, even though there is expected to be some residual risk of SA separation from the NEM after a new interconnector is energised (this is expected to be low given the double circuit configuration of both interconnectors.[45]

4.1.3 The impact on system security and reliability needs

A number of parties requested that the impacts on system security following the assumed retirement of South Australian gas-fired generators are explained. Commentary was made that the assumptions regarding system inertia need to align with AEMO's ISP inertia assumptions, and additional fault levels and voltage regulation will be required if the South Australian gas-fired generators retire (and should be costed).[46]

In December 2018, AEMO declared an inertia shortfall (and confirmed a previously declared system strength gap) in South Australia as part of the 2018 NTNDP. In particular, AEMO commented that:[47]

- the fault level shortfall declared in South Australia will remain until new high-inertia synchronous condensers are installed by ElectraNet to address the system strength need; and
- in terms of the inertia shortfall, it is recommended ElectraNet fit flywheels to the proposed synchronous condensers and consider opportunities for developments that provide fast frequency response (FFR).

Once a new interconnector is energised, the risk that South Australia will be separated is reduced and the inertia shortfall is no longer likely to be an issue.

---

44 Should power flows across one AC path reach 950 MW with the other path out of service, loss of synchronism protection will engage and sever the path. ElectraNet has adopted this as the pre-contingent limit across all interconnector options with a 100 MW safety margin applied.

45 CQ Partners, SA-NSW Interconnection – Analysis of Impacts on Liquidity in SA, p. 6

46 EnergyAustralia, p. 2 and Origin Energy, pp. 2-3.

47 AEMO, 2018 NTNDP, December 2018, pp. 4-5.

Delta Electricity suggested that an explicit scenario involving South Australia gas generators shutting down should be assessed, as well as the cost of maintaining system security and reliability if a South Australia – New South Wales interconnector trips (eg, through AEMO's Reliability and Emergency Reserve Trader (RERT) response).[48] Section 3.3 outlines how all options considered can provide benefits from enhancing security of supply in South Australia, while section 8.5 demonstrates that, even if these plants are assumed to retire with a new interconnector in-place, Option C.3 is preferred and has strongly positive estimated net market benefits.

EnergyAustralia suggested that the identified need should not include enhancing system security as this has been addressed in recent market developments and rule changes.[49] Section 3.3 outlines how options can contribute to meeting system security standards in South Australia at lower cost than would otherwise be the case.

MEA Group queried the decision not to explicitly model FCAS benefits given these costs have been the cause of significant price spikes across South Australia over the past five years, growing from $5 million per annum to above $50 million per annum.[50] Renew Estate commented that including storage along the path of the preferred option can provide FCAS services.[51] While storage may help provide these services, FCAS has not been captured in the analysis since changes in FCAS costs are not material in terms of identifying the preferred option (Appendix D provides more detail).

ElectraNet is addressing the declared system strength gap outside of this RIT-T process. ElectraNet has recommended to AEMO that the installation of four large synchronous condensers will meet the system strength gap. The proposed system strength solution will enable the South Australian power system to be operated without directing synchronous generators on for system strength purposes.

4.2 Feedback on the market modelling approach and assumptions

Submissions raised a number of points in relation to the market modelling approach adopted for this RIT-T, as well as the specific assumptions made.

4.2.1 Higher NSW coal prices should be tested

Several parties expressed the view that black coal generator fuel costs, particularly those in New South Wales, should be higher than modelled in the PADR. Some parties commented that higher coal prices may lead to earlier black coal generator retirements, which would reduce the estimated benefits.[52]

The core scenarios in the PADR, and this PACR, use the fuel cost inputs that were consulted on as part of AEMO's annual planning processes and reviewed as part of the ISP (with the exception of gas prices, where we investigate a wider range than that contemplated in the ISP).

48 Delta Electricity, pp. 2-3

49 EnergyAustralia, p. 2.

50 MEA Group, p. 1

51 Renew Estate, p. 2

52 Delta Electricity, p. 2, Origin Energy, pp. 1-2 and SEA Gas, pp. 2-3;

However, in response to submissions, we have also investigated a sensitivity assuming $6.80/GJ black coal fuel costs for New South Wales generators, as suggested by Delta Electricity,[53] which is significantly higher than the ISP forecasts.[54] Section 8.6.4 illustrates that assuming these higher coal prices decreases the estimated net market benefits of the preferred option by approximately $635 million (to $130 million), but that the net market benefit remains materially positive.

4.2.2 Consistency of the 'REZ benefit' with the RIT-T framework

A range of submitters queried whether the RIT-T framework could include benefits associated with the avoided transmission costs associated with future REZ development, as these benefits are speculative and not supported by the RIT-T framework.[55]

While the PADR referred to these benefits as 'avoided REZ transmission capex' or 'REZ benefit', they formally fit within the RIT-T and NER benefit category of the 'difference in the timing of unrelated transmission investment' category.

We have labelled this benefit 'avoided REZ transmission capex' in this PACR, to distinguish it from other benefits arising from the deferral of unrelated transmission investment (notably the potential impact on the second stage of QNI investment if a South Australia – Queensland interconnector is pursued). The inclusion of this benefit in the RIT-T is consistent with the guidance provided by the AER in its recently updated RIT-T Application Guidelines.[56]

AEMO's ISP assessment included benefits arising from the avoidance of additional transmission investment to support REZ development. A key development in the market modelling between this PACR and the earlier PADR has been to directly model these benefits within the wholesale market model used for the RIT-T assessment.

This has also led to changes in the specification of some of the options, specifically those involving HVDC, to incorporate mid-point converter stations, which would be required in order to enable new renewable generation connection, to realise these benefits (these costs for Option B and Option C.3.iii are outlined further in sections 5.2 and 5.3.3 below).

The modelling for this PACR has confirmed the ISP finding that the benefits associated with avoided REZ transmission capex are material for all of the new interconnector options at 330 kV and above (but are not materially different between options in the sense that they do not affect the RIT-T outcome).

These benefits are generally expected to accrue towards the back end of the assessment period (from the mid-2030s), as shown in section 7, as this aligns with the timing of the transmission investment which would otherwise be needed to connect renewable generation to replace retiring plant.

---

53 Delta Electricity, p. 2.

54 By comparison, the highest coal price contemplated by the ISP for existing generators is $4.11/GJ across the entire assessment period, see: 'Integrated System Plan Assumptions workbook v2.4' available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

55 Delta Electricity, p 5, EnergyAustralia, p. 6, AEC, p. 3 and TEC, p. 2.

56 Specifically, Example 6 of the December 2018 final AER RIT-T Application Guidelines.

ARCMesh queried whether these benefits have been included along routes other than the New South Wales route, noting that no allowance appeared to have been included for the Queensland route.[57] We note that these benefits had not been included in the earlier PADR assessment for the Queensland route, but have now been included in this PACR assessment.[58]

However, realising this benefit with HVDC transmission options requires the inclusion of additional mid-point converter stations, which adds substantially to the costs of this option and the HVDC option between South Australia and New South Wales. Mid-point converter stations were added to the two HVDC options to capture these benefits.

Some parties requested that additional detail on the specific REZ transmission costs that are assumed to be avoided be provided.[59] The ISP assumptions regarding these costs were adopted in the PADR, whereby renewables close to the network connect in the first ten years of the forecast period, after which the penalty cost of unlocking more distant renewable generation is factored into the modelling.

Section 6.3 outlines how the modelling of these benefits has been refined since the PADR. We note that the magnitude of the benefits have fallen under our direct modelling approach.

A number of parties suggested that alternate funding mechanisms for REZ development, potentially incorporating generator contributions, needs to be developed in order to more fairly allocate risks.[60] ElectraNet notes that these costs reflect real resource costs that should be included in a robust economic assessment (such as the RIT-T and the ISP) regardless of who funds these costs. The issue of funding such connections sits outside of this process.

4.2.3 Treatment of uncertainty in relation to renewable policies and emissions outcomes

The Energy Project and the Public Interest Advocacy Centre (PIAC) commented that long-term stability is required to generate the modelled market benefits and, in relation to the stability of renewable policies, the approach taken in the PADR is optimistic.[61] Their view was that any disruption makes it difficult to determine if any investment is in the long-term interest of consumers.

We recognise that uncertainty in relation to future policy and market developments has the potential to impact the costs and benefits of the investments being considered under this RIT-T, and that environmental policies are currently particularly uncertain. However, we do not agree that investment cannot be assessed and cannot proceed while there is uncertainty, as such uncertainty about the future can be expected to be enduring. Indeed, the RIT-T addresses such uncertainty through the requirement to consider scenarios and sensitivity analysis as part of the assessment.[62]

---

57 ARCMesh, p. 12.

58 The specific REZ that is picked up by the Queensland route is that near Broken Hill in New South Wales.

59 AusNet Services, p. 3 and MEA Group, p. 1.

60 The Energy Project, p. 21, SACOSS, p. 3, PIAC, p. 2, EUAA, pp. 5-7 and Business SA, p. 2.

61 The Energy Project, p. 5 and PIAC, p. 1.

62 The use of scenarios and sensitivity analysis in the RIT-T assessment is discussed further in section 7.

The RIT-T assessment in this PACR uses three scenarios reflecting a broad range of potential outcomes across the key uncertainties that are expected to affect the future market benefits of the options being considered, including future emissions policies.

In forming these scenarios, we have drawn on the 2018 ISP inputs developed and consulted on by AEMO, and for some inputs (including in relation to emissions targets) we have broadened these assumptions in the high and low scenarios to more strenuously test the robustness of the RIT-T outcome.

The variables included in each scenario 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.

There is obviously continuing uncertainty in relation to future emissions and reliability policies in the NEM, with the National Energy Guarantee (NEG) policy no longer being Federal Government policy, albeit that the reliability component of the NEG may form part of an alternative future policy. The issue of the NEG was raised by a number of parties in submissions, with various views offered as to whether it should be explicitly modelled or not.[63]

Notwithstanding the uncertainty about the specifics of future federal emissions policies, the central scenario used for the modelling for this RIT-T includes a constraint on overall emission levels that reflects Australia’s COP 21 commitments (with the high and low scenarios testing alternative emissions targets), as well as a constraint on generation planting to ensure that the NEM reliability standard is met in all future periods.[64]

This approach is consistent with that adopted by AEMO in the ISP, and focuses on the outcomes that future policies need to deliver in order to comply with existing commitments, rather than on the policy that achieves those outcomes.

We have also assumed outcomes consistent with the jurisdictional emissions targets in Victoria and Queensland, in all scenarios. This is in line with the approach taken in the ISP.

The PACR finding that a new 330 kV interconnector between Robertstown in South Australia and Wagga Wagga in New South Wales, via Buronga, is expected to deliver the highest net market benefits, is robust across this range of future scenarios and sensitivity tests, as shown in section 8.

63 AEC and Engie for example submitted that the NEG should be explicitly modelled, while Origin Energy suggested that the NEG should be removed from the modelling. See: AEC, p. 3, Engie, p. 2 and Origin Energy, p. 1.

64 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.

Several submissions also raised queries in relation to emissions outcomes between the different options.[65] As noted above, the market modelling includes compliance with emissions limits consistent with Australia's COP 21 commitments as a constraint in the central scenario, which means that all outcomes modelled have emissions levels that are consistent with these targets. In addition, we have also reported as part of the results the carbon emission quantities associated with each option.[66]

The Central Irrigation Trust and ARCMesh inquired as to whether the diversity in renewable energy output has been modelled across regions.[67] We have included diversity in renewable output over the assessment period in the modelling and have drawn on AEMO's ISP assumptions in relation to diversity. The ISP assessed in great detail the diversity of renewable resources and their ability to demand-match (refer to Appendix A of the ISP for more detail on the correlation between renewable resources across NEM).

More broadly, a number of parties commented that the scenarios adopted in the PADR did not cover a sufficient range of potential uncertainties. We note that the role of the scenarios in the analysis is to test the robustness of the RIT-T outcome to variations in the values associated with the key drivers of the costs and market benefits. We consider that the parameters captured in the scenario analysis do cover the key drivers of market benefits for this RIT-T, and therefore have not added additional parameters into these scenarios.

4.2.4 Impact of high scenario on RIT-T outcome

Engie, EnergyAustralia and AEC expressed concerns that the outcomes in the PADR were biased by the inclusion of the high scenario.

We noted in the PADR the substantial benefits that accrue under the high scenario. We tested the sensitivity of the RIT-T outcome to the weights applied to the three scenarios and found that the PADR conclusions were not dependent on the scenario weightings adopted. Moreover, the PADR assessment found that the preferred option would be the same even with a zero weighting applied to the high case.

We have re-run this sensitivity test in relation to scenario weightings for this PACR and continue to find that the preferred option does not depend on the weightings given to the scenarios. As a consequence, neither the PADR outcome not the PACR outcome has been biased by the inclusion of the high scenario.

The high scenario is intended to represent an 'upper end' of the envelope of potential outcomes against which the robustness of the RIT-T outcome is being tested. We therefore consider that it is appropriate that the high scenario includes upper end assumptions in relation to the various parameters.

65 EnergyAustralia, p. 6, Engie, p. 4 and TEC pp. 3 & 5.

66 Refer to emissions output data released alongside the PACR.

67 CIT, p. 1 & ARCMesh, p. 22.

AEC commented that the high scenario was unrealistic, since it included both a high gas price and a more onerous RoCoF constraint.[68] The PACR modelling now applies the current South Australian Government inertia requirement (ie, the 3 Hz/s) to all scenarios investigated. As a consequence, the extent of benefits under the high scenario has fallen in this PACR.

Delta Electricity stated that different scenarios should be investigated, rather than sensitivity analysis where one assumption is varied at a time.[69] Our scenario analysis does vary several parameters at the same time. The additional sensitivity analysis is intended to indicate whether additional variables could affect the analysis.

The sensitivity testing undertaken is common practice and, by varying a single variable in each case, the effect of the variable can be determined. If this method is altered, say where multiple variables are tested at the same time, it would not be possible to determine the effect of each variable individually and therefore which are the most significant variables in the assessment.

4.2.5 Transparency around the modelling approach and results

A number of parties requested additional information in relation to the detailed modelling undertaken and the results.[70] These submissions and the requested detail are discussed further in the separate market modelling report being published alongside this PACR.

One submission called for greater clarity of the benefits that accrue over the short-term. Section 8 presents the breakdown of the annual estimated gross benefits of the preferred option for each year of the assessment period, which shows the changing pattern of benefits over time for each scenario investigated.

ARCMesh submitted that the market modelling undertaken in the PADR assumed a premature retirement of relatively modern coal-fired generators in Queensland.[71] This is an inaccurate assertion and these coal plants are instead assumed to retire at the end of their technical life, which is consistent with AEMO's assessment in the ISP. While the wholesale market model used does allow for generators to retire early, this was not found to be the case in the PADR modelling (nor in the PACR modelling).

4.3 Cost and specification of options

Various points were raised in submissions that have led to changes in the detailed specification and costs of the options assessed in this PACR, as well as to the inclusion of two new options.

68 Engie, p. 3 and AEC, pp. 2-3.

69 Delta Electricity, p. 4.

70 Delta Electricity, p. 3, EnergyAustralia, pp. 2 & 9, Engie, pp. 2-3 and AEC, p. 3.

71 ARCMesh, pp. 2-5.

4.3.1 Viability of the non-interconnector option and interim solutions

Several submissions commented on the specification of the non-interconnector option in the PADR. In particular EnergyAustralia commented that the non-interconnector option preserves local generation in South Australia, and therefore the supply of hedge contracts.[72] They also commented that load shedding treatment is not comparable between the interconnector and non-interconnector options, and that the Entura dispatch cases are not realistic as TIPS is dispatched ahead of Pelican Point.

The Total Environment Centre (TEC), Energy Consumers Australia and The Energy Project considered that the non-interconnector costs have been overstated, and that more detail should be provided.[73] Origin also commented that Entura has not demonstrated that its option was the lowest cost non-interconnector option, whilst TEC considered that the potential for demand response had been dismissed by Entura and recommends using DER to manage peak demand.

In contrast, the AEC considered that the non-interconnector option does not meet the performance requirements and hence is not comparable to the other options. ElectraNet agrees that the non-interconnector options does not provide the same level of system security as an interconnector option.

We engaged Entura to consider and respond to comments made on non-interconnector solutions, as well as specific comments on their earlier assessment.

Due to the variety of points raised in submissions and consultative sessions in relation to the viability of the non-interconnector option, we have not responded to each in this section. Instead, Appendix C provides responses from ElectraNet and Entura on each point individually, which Appendix F provides a detailed response on the points raised by The Energy Project.

While we have not changed the scope of this option since the PADR, we have responded to points raised in submissions and have undertaken further costing analysis in relation to the battery components of the non-interconnector option. Specifically, we have taken into account the opportunities for additional revenue streams for this component in further refining the costs, which have now reduced by approximately 15 per cent.

Some respondents were interested in non-interconnector solutions that could be put in-place before a new interconnector is energised, ie, between now and 2022/23. Renew Estate commented that including storage along the path of the preferred option can improve interconnector capability and provide renewable firming and FCAS services.[74]

We have undertaken with Entura an assessment of least-cost short-term non-interconnector solutions that could be implemented before 2022/23. Candidate services identified were: (1) system strength; (2) inertia (RoCoF); and (3) helping fill a shortage of FCAS when under a prior outage of Heywood. Section 5.5 summarises the results of this assessment and, while there is not considered to be a role for these solutions in the interim on an economic basis, there may be in the longer-term.

---

72 EnergyAustralia, p. 4.

73 TEC, p. 2, The Energy Project, p. 2, Energy Consumers Australia, p. 3.

74 Renew Estate, p. 2.

4.3.2 Cost and specification assumed for the HVDC option

ARCMesh's submission considered that the costs of the HVDC option considered in the PADR were too high, relative to HVAC. In particular, they have undertaken extensive assessments of the scope and design of an HVDC option to Queensland, including engaging estimators, and quote that the capital costs in the PADR could be between 16 and 22 per cent lower. ARCMesh also consider that a superior route for the Queensland option would be to head due west, parallel to the Queensland and New South Wales border.[75]

In light of this submission, we undertook further assessment of the likely costs and routing of HVDC options. Appendix G summarises this assessment and provides a detailed response to all points raised by ARCMesh, both in its submission to the PADR as well as during participation in the stakeholder deep dive sessions held as part of our detailed consultation on this RIT-T. Appendix H provides a high-level comparison of HVDC and HVAC systems.

In addition, we engaged engineering firm Jacobs to independently review the transmission line estimates of Option B, generally and in light of ARCMesh's specific comments. The Jacobs' report is included as a standalone report accompanying this PACR.

We have reflected the finding of this assessment in the costs that have been assumed for the HVDC option considered for new interconnection between South Australia and Queensland (Option B). Given the interest in HVDC technology shown in submissions, we have also included an additional variant of the SA-New South Wales interconnector option that incorporates an HVDC link (rather than an AC link) between Robertstown in SA and Darlington Point in New South Wales (ie, new Option C.3.iii).

However, we note that in order to capture the benefits associated with avoiding transmission investment to connect new renewable generation, both of the HVDC options considered need to incorporate mid-point converter stations, which has been added to the two HVDC options. This adds substantially to the costs of these options, despite the cost reduction assumed in the HVDC transmission lines.

Throughout the course of this RIT-T, we have worked closely with Powerlink on this option. Powerlink's submission noted this and how Powerlink has worked collaboratively with ElectraNet on Option B to define the scope and provide input into the cost of this option, assess the impact that this option has on the existing power transfer limits of the interconnected NEM and review the technical assumptions for assessing the market benefits.[76]

ARCMesh also queried the approach taken to estimating changes in network losses for the HVDC options, compared to the HVAC options. In particular, ARCMesh stated that, while DC power flow modelling is appropriate for AC interconnectors, it underestimates the reduction in losses expected for HVDC.[77] We do not agree with the view expressed by ARCMesh regarding the applicability of the approach taken to modelling losses for HVDC options and, moreover, note that, even if it did underestimate the reduction in losses, it is unlikely to be material in the identification of the preferred option.

---

75 ARCMesh, pp. 5-8 & 11.

76 Powerlink, p. 1.

77 ARCMesh, pp. 13-14.

4.3.3 The South Australia - Victoria option and network hardening costs

AusNet Services proposed alternative route options for a new South Australia - Victoria interconnector (Option D), including via Sydenham instead of Moorabool, which it considered would avoid bushfire risks.[78]

It also considered that the 'network hardening' assumption made in the PADR to reflect operational risks associated with bushfires (which reflect the costs of 300 MW OCGT) is unreasonable and could be mitigated with lower cost options, and noted that the risk of a bushfire leading to coincident and wide spread damage to both the existing Heywood interconnector and a new interconnector is not currently classified by AEMO as a credible contingency.

The alternative routes proposed by AusNet Services all focus on addressing the potential bushfire risk in South Australia by avoiding routing through Tungkillo. However, all of the routes continue to go via Horsham and Ballarat, and therefore continue to present a substantial bushfire risk in what has been identified as a high bushfire area.[79]

We therefore continue to consider that the risks of bushfires in the area traversed by a new South Australia - Victoria interconnector is material and would need to be addressed through the inclusion of network hardening measures of the order assumed in the PADR, in order to manage the risks to remain at the same level as currently.

AusNet Services also submitted that the costs associated with the Western Victoria augmentation should be removed from Option D in the SAET RIT-T assessment, as this investment is being progressed via a separate RIT-T.[80]

In the PADR we included the full costs of the augmentation as part of Option D, and took account of the interaction between the two RIT-T processes via inclusion of a sensitivity in relation to the Western Victoria RIT-T, which excluded the costs that are common with that separate investment. However, in light of the publication of the PADR for the separate Western Victoria RIT-T[81] and the augmentation being identified by AEMO in the ISP as a Group 1 project for immediate progression, we have revised our approach in this RIT-T to exclude these costs from Option D.

We have, however, considered the impact of this assumption via a sensitivity which continues to incorporate all of these costs as part of Option D (see section 8.5.2).

The MEA Group submitted that modelling should be done in consultation with AEMO to clearly understand the benefits that flow from including 50 per cent series compensation between Robertstown and Buronga.[82]

---

78 AusNet Services, pp. 2-3.

79 See for example, the State Government of Victoria's bushfire risk map, available at: https://services.land.vic.gov.au/landchannel/images/bushfire_prone_area_state.png

80 AusNet Services, pp. 3-4. A similar point was made by Engie in their submission (see pp. 3-4) and The Energy Project at the Sydney deep dive session on 16 August 2018.

81 AEMO, *Western Victoria Renewable Integration December*, Project Assessment Draft Report, December 2018.

82 MEA Group, pp. 1-2.

We have worked closely with AEMO throughout the course of this RIT-T, including in considering the benefits of series compensation. Since the PADR was released, we are no longer considering option variants that involve series compensation (ie, Option 3i and Option 4i in the PADR) as further technical assessment has identified alternatives that provide the same capability, but avoid potentially restricting the connection of renewable generation to the series compensated line section.[83]

4.3.4 Alternative South Australia to NSW route options, including via Victoria

AusNet Services proposed an alternative route option for a new SA-New South Wales interconnector via Kerang in Victoria, which it considered would enable exploitation of renewable energy resources in Victoria. AusNet Services considers that this variant provides most (if not all) of the benefits of the Victorian option modelled in the PADR as well as additional benefits from avoided REZ transmission costs to support renewable generation developments on the Red Cliffs – Kerang line in Victoria that are forecast by the ISP to connect in the mid-2020's, as well as bringing forward the benefits from stronger interconnection between New South Wales and Victoria through the SnowyLink South project.[84]

We have included a new option in the PACR assessment (Option C.3ii) that reflects the option suggested by AusNet Services. This option is described in section 5.3.2, with the results reported in section 8.

A number of parties submitted that the route outlined in the PADR could be enhanced by the addition of the Buronga to Red Cliffs upgrade included in the ISP.[85] This augmentation has now been included in all of the South Australia – New South Wales options assessed and Appendix E summarises AEMO's assessment of the incremental net market benefits of this augmentation.

Havilah Resources, a resource company seeking network connection in the Broken Hill area, proposed a line route from Burra towards Broken Hill and back towards Wagga.[86] They commented that the increased cost of this alternative line route should not hinder long-term strategic infrastructure development. Similarly, SACOME's submission suggested that an interconnector path via the Braemer province should be considered, in order to facilitate mining loads in that area, which would provide wider state economic benefits.[87]

Whilst noting these submissions, our assessment is that in both cases the additional costs of these routes would not be outweighed by a corresponding increase in benefits within the electricity market. As noted earlier, the RIT-T framework does not incorporate consideration of broader benefits to the wider economy. We have also engaged AME Advisory to undertake an independent analysis of the issues raised in relation to the Curnamona Province, which has been released alongside this PACR.

---

83 Arising from the potential risk of sub-synchronous oscillations and consequential damage to generators and network equipment connected to the series compensated line section.

84 AusNet Services, pp. 4-5.

85 AusNet Services, p. 5, MEA Group, p. 2 & South Australia Department for Energy and Mining, p. 46.

86 Havilah Resources, pp. 4-5.

87 SACOME, pp. 9-10.

4.4 Staging of options and coordination with other transmission developments

The South Australian Government highlighted in its submission that it is targeting an interconnector between South Australia and New South Wales to be in-place by mid-2021. To this end, the government has committed up to $14 million for early works and to fast-track planning and regulatory approvals.[88] As part of the New South Wales Transmission Infrastructure Strategy released in November 2018, the New South Wales government announced a similar policy stating that it aims to accelerate the delivery of a new South Australia - New South Wales interconnector by 2023.[89]

The expected energisation date of the interconnector options is in the period 2022-2024, with a 1 July 2023 date assumed in the detailed modelling. However, ElectraNet is working with the South Australian Government to investigate an expedited delivery of the preferred interconnector option which increases the likelihood of achieving a 2022 delivery date.

PIAC, SACOSS, the EUAA and The Energy Project also suggested that a potential staged implementation of the preferred option should be examined.[90] We considered the staging of investment for all interconnector options as part of the pre-screening exercise prior to the PADR release and reported this analysis in the PADR.

A key conclusion from this assessment was 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).

We also note that the benefits that have been identified in relation to the alternative options rely on the entire investment being in place. That is, in the case of a new SA- New South Wales interconnector, the expected near-term benefits accruing in South Australia would not be realised in the absence of the full investment on the New South Wales side of the border.

There is therefore no scope to adopt 'a more strategically timed approach to the New South Wales elements'[91] of the investment without forgoing the substantial benefits that are expected to accrue immediately the investment is put in place.

The Energy Project queried whether further network investments are needed in New South Wales to unlock all potential benefits for consumers.[92] We note that the benefits of the preferred option stand by themselves and compound when further upgrades are added, as per the ISP. Moreover, while the new interconnector would add around 800 MW of transfer capacity between the regions, it provides closer to 1,400 MW of additional connection capacity towards the deeper network in New South Wales.

The TEC submitted that the benefit of deferring an interconnector by using non-interconnector technologies in the short- to medium-term has not been considered.[93]

---

88 Hon Dan van Holst Pellekaan MP (Minister for Energy and Mining), p. 1.

89 NSW Transmission Infrastructure Strategy, available at: https://energy.nsw.gov.au/renewables/clean-energy-initiatives/transmission-infrastructure-strategy#-nsw-transmission-infrastructure-strategy-

90 PIAC, p. 2, SACOSS, p. 2, EUAA, p. 4 and The Energy Project, p. 6.

91 The Energy Project, August submission, p. 25 and November supplementary submission, p. 11.

92 This was raised by the Energy Project at the Sydney public forum on 16 August 2018.

93 TEC, pp. 4-5.

We note that, even if the deferral of the preferred option could be achieved through non-interconnector options, this is not expected to deliver greater net market benefits since:

- the annual benefit of deferring the expenditure is in the order of $90 million;
- there are expected annual benefits of around $250 million in the first few years after energising; and
- there would be significant costs associated with procuring the non-interconnector options.

A number of parties suggested that the net market benefits should be investigated with Snowy 2.0 assumed to be in-place. Since the PADR was released, AEMO has published its inaugural ISP, which excluded the proposed Snowy 2.0 project in its main network development path since it does not meet AEMO's definition of committed, but includes it in a separate scenario to examine how it may support the flexibility and system security requirements of the future energy mix.

We consider that Snowy 2.0 is unlikely to have a material additional impact on the dispatch of South Australia's gas generation fleet and, moreover, the most likely option to be influenced by Snowy 2.0 is the preferred option.

Specifically, following the completion of the preferred option, there is expected to be an increase in congestion between Canberra and Sydney and Snowy 2.0 is likely to result in an increase in the amount of transmission between these locations, thereby alleviating congestion following energising of the preferred option. This is expected to increase the benefits of the preferred option, as the two are complementary developments, and do not alter the relativities between the options.

We have also conducted a sensitivity for the South Australia to Queensland option (Option B) that considers the potential for this option to defer the second stage of the QNI Group 2 upgrade identified in the ISP. Section 8.5.1 outlines how this actually decreases the estimated net market benefits of Option B.

4.5 Specific comments on RIT-T analysis framework

Some submissions raised specific comments on the framework adopted for the RIT-T analysis, including the assessment timeframe, use of scenarios and discount rate.

4.5.1 Assessment period

The PADR adopted a 21-year time period for the assessment. A number of parties contended that assuming a shorter period would favour the non-interconnector option.[94]

[94] The Energy Project, p. 5, PIAC, p. 1; and Energy Consumers Australia, p. 3, TEC, p. 2 Business SA, p. 1 and SACOSS, pp. 2-3.

The NER and the AER's RIT-T Application Guidelines are not prescriptive regarding the choice of assessment period, saying only that 'the duration of modelling periods should take into account the size, complexity and expected life of the relevant credible option to provide a reasonable indication of the market benefits and costs of the credible option'. However, the AER Guidelines do state that:[95]

> 'in the case of very long-lived and high-cost investments, it may be necessary to adopt a modelling period of 20 years or more'

Other RIT-T assessments of interconnectors and other major transmission augmentation (ie, 'long-lived and high-cost investments') in Australia have adopted assessment periods ranging from 20 to 50 years.[96] This includes RIT-Ts completed within the last year, as well as earlier RIT-Ts where the extent of uncertainty in relation to future energy sector policies, generator retirements and future demand outlook was arguably as uncertain as it remains today.

In responding to points raised regarding the assessment period, we sought advice from HoustonKemp Economists on the appropriate assessment period for the investments being considered in this RIT-T.[97]

HoustonKemp highlights that the guiding principle for determining the relevant assessment period should be that it is sufficiently long so that it captures the key differences in the costs and market benefits across the credible options assessed. That is, the assessment period should be the point at which identification of the preferred option stabilises, and assuming a longer period would not change the identified preferred option, as beyond this point the relativity of the costs and benefits between options is not expected to change materially.

We adopted an assessment period extending to 2040 to ensure that both short and long-term market benefits are captured, consistent with the long-lived nature of the assets involved. Given the difference between options in relation to longer term benefits, this approach provides a reasonable indication of the differences in expected net market benefits between options over their expected life.

Adopting a shorter assessment period risks identifying a suboptimal option as preferred, as it would omit the market benefits associated with options that enable New South Wales demand to be met with low cost generation as New South Wales coal plant retires in the 2030s, as well as omitting the benefit from avoiding transmission expenditure that is expected to be required to connect REZs from the mid-2030s.

In both cases, these benefits, although longer term, still occur relatively early in the overall expected life of the assets. Since these longer-term benefits do not accrue equally across all options, omitting them would result in material differences in the benefits expected between options not being taken into account in the investment decision.

---

95 AER, *RIT-T Application Guidelines*, September 2017, p. 39. This was also reiterated in the recently updated AER Guidelines, see: AER, *RIT-T Application Guidelines*, December 2018, p. 63.

96 The 2014 TransGrid and Powerlink QNI RIT-T adopted a 50-year assessment period, whilst the RIT-T conducted by AEMO and ElectraNet for the Heywood interconnector upgrade adopted a 41-year period. More recently, the TransGrid and Ausgrid Powering Sydney's Future RIT-T and the recently completed ElectraNet Eyre Peninsula RIT-T both adopted a 20-year assessment period.

97 This advice has been released alongside this PACR.

We also tested the robustness of the RIT-T outcome to the adoption of a shorter assessment period and found it to not be affected (see section 8.6.5).

Appendix F provides additional detail on the considerations going into selecting the assessment period length more generally.

The Energy Project presented analysis over a 15-year period (that was also referred to in other submissions), which misinterpreted the terminal value concept and incorrectly identified Option A as being preferred over this shorter period. We have engaged directly with The Energy Project to clarify the approach used. A full discussion of the use of terminal values can be found in Appendix F.

4.5.2 Discount rate

A number of parties raised queries about the discount rates used in the assessment. Specifically:

- The AEC questioned the use of the central 6 per cent 'weighted average cost of capital' (WACC) since it is more reflective of the returns expected from low-risk and regulated assets than for assets such as generators which are exposed to market risk[98] and
- SEA Gas commented that the high 'proposed WACC' used in the RIT-T should be increased on account of it being below the observed 10-year bond rate during 1970s and 1980s, unless some other form of regulatory protection is applied.[99]

The Energy Project also raised a number of points in relation to the discount rates used (which were referenced by other submitters). We cover each of these points in Appendix F, which responds to the various issues raised by The Energy Project (and other respondents that refer to The Energy Project analysis).

ElectraNet notes that the discount rate in the RIT-T differs fundamentally in purpose to any regulated rate of return (or 'WACC').

Specifically, the discount rate in the RIT-T is required to be 'commercial' (distinct from 'regulated') and is used purely to take account of the time-value-of-money ensuring costs and benefits are in the same denominated unit, while the regulated rate of return explicitly determines the annual return on assets network businesses like ElectraNet are permitted to earn.

The 6 per cent central discount rate is in line with other recent RIT-T assessments.[100] We have tested the sensitivity of the assumed discount rate to a lower bound of 3.8 per cent and an upper bound of 8.5 per cent, and found that Option C.3 continues to be identified as the preferred option within this range.[101]

---

98 AEC, p. 3.

99 SEA Gas, pp. 2-3

100 Including that used by AEMO in its current Western Victoria RIT-T and that used by TransGrid and Ausgrid in the 2017 Powering Sydney's Future RIT-T, as well as by Ausgrid and Jemena in recent RIT-Ds. We note that Powerlink has used a slightly higher central discount rate of 7.04 per cent in its recent repex RIT-Ts, which is within the sensitivity tested in this PACR.

101 See section 8.5. We note The Energy Project's assertion in its original submission (p. 22) that 'the NPV results appear to be quite sensitive [..] to discount rates'. The analysis presented in section 8.5.5 refutes this statement.

We have also assessed the boundary value at which the choice of discount rate would no longer result in Option C.3 having positive estimated net market benefits, and found this value to be close to 14 per cent (real, pre-tax), as set out in section 8.5.5.

4.5.3 Cost estimates and the sharing of costs (and risks) between regions

A number of parties raised queries regarding the cost estimates used for the interconnector options, including:

- SACOME who queried the basis of estimates and noted that a material increase in costs would reduce the net market benefits and impact on whether a new interconnector proceeds to construction;[102]
- Origin Energy highlighted that the complexities of constructing large transmission projects should be accounted for to ensure that market participants have as accurate a view of the costs as possible (and specified an allowance for contingency capex, native title, development approval and any required deep network augmentation);[103]
- Similarly, Delta Electricity suggested that the cost estimates appeared to be standardised and not take account of the unique costs and challenges of the routes assessed (eg, environmental approvals and acquiring easements);[104] and
- the AEC stressed the need to ensure that the estimated cost at this stage is robustly derived and that, should the project be energised, the 'as-built' cost is close to the expected cost.[105]

ElectraNet agrees with each of these points and notes that significant effort has gone into the cost estimates used in this RIT-T, including through engaging external consultants to provide independent reviews and estimates.

In our opinion, the costs have been estimated as accurately as is realistically possible at this stage and take account of all relevant contributing factors for projects of this size. In saying this, uncertainty still exists and so we have undertaken specific sensitivity testing of the result to the assumed capital costs (as set out in section 8.5 below).

ARCMesh estimated that the HVAC options to New South Wales should have their costs increased by approximately $530 million from those quoted in the PADR, with $500 million being attributed to having to build a 330 kV line from Wagga to Yass.[106]

While ElectraNet's modelling finds congestion on this transmission route (ie, deeper in the New South Wales network), which restricts the benefits of the interconnector options, neither the costs or benefits of relieving this congestion have been included in the assessment and would be subject to a separate RIT-T process.[107]

---

[102] SACOME, pp. 7-8.

[103] Origin Energy, p. 2.

[104] Delta Electricity, p. 2.

[105] AEC, p. 1.

[106] ARCMesh, p. 9.

[107] This is expanded on in Appendix G.

This applies to all jurisdictions investigated. An important point here is that augmenting the deeper network from Wagga to Yass would not only add costs to the HVAC options to New South Wales as suggested by ARCMesh, but would also deliver material additional market benefits that are expected to outweigh the additional costs.

A number of parties commented that the allocation of costs and benefits are disproportionately split between New South Wales and South Australia.[108] We note that the RIT-T is required to look at market benefits across the NEM as a whole to find the optimal solution, without assessing inter-regional impacts. Cost allocation, and the sharing of risk, sit outside of the RIT-T process and changes to the regulatory framework in this regard are currently being considered by governments and regulators.

Under the NER, where transmission assets in one region are used to supply customers in another region, part of the cost of those assets are charged to customers in the importing region through an 'inter-regional TUOS' or 'IR-TUOS' charge. The Energy Project expressed the view that estimating the impact of the IR-TUOS regime would help customers engage in the RIT-T process.[109]

The current arrangements for determining IR-TUOS have been in place since February 2013 and were intended to make TUOS charges more reflective of the actual costs incurred in providing transmission services. However, the current regime only takes into account peak annual usage for each asset and does not consider the extent of energy flows between regions, or the contribution assets make to providing system strength or contributing to system stability in other ways.

ElectraNet would support a broader review of the continuing suitability of the current IR-TUOS arrangements, and whether modifications would result in a more equitable allocation of costs between customers in different regions based on the benefits that assets provide to those regions, regardless of the asset's geographic location. Notwithstanding this, the appropriateness of the current IR-TUOS arrangements is an issue that is separate to this RIT-T application, and modifications to the arrangements are not precluded by the outcome of this RIT-T.

Because it is based on the peak utilisation of each asset, forecasting IR-TUOS charges is both complex and highly uncertain. ElectraNet's experience has been that IR-TUOS charges can fluctuate substantially from year to year for interconnector assets. We have not therefore attempted to forecast IR-TUOS as part of this PACR.

We note that the AEMC recently stated, as part of its final report on the coordination of generation and transmission investment in December 2018, that there may be some elements of the existing inter-regional transmission charging arrangements that could be changed to better align the costs of interconnectors with those that benefit from the investment. The AEMC recommend that these should be considered in more depth through re-examining the IR-TUOS arrangements, and work will commence in March 2019 on this.[110]

---

108 Delta Electricity, p. 3, Origin Energy, p. 2, The Energy Project, p. 2, PIAC, p. 2, Energy Consumers Australia, p. 3 & TEC, p. 2.

109 TEP submission, p. 16.

110 AEMC, *Coordination of Generation and Transmission Investment*, Final Report, 21 December 2018, p. viii.

The updated ACIL Allen assessment of the potential impact on electricity prices and assessment of the broader economic benefits finds that the network costs that are attributed to customers in South Australia and New South Wales are in fact proportionate to the bill reduction benefits each are expected to receive.

The figure below re-presents this finding and additional detail can be found in the updated ACIL Allen report, which has been released alongside this PACR.

Figure 6 – ACIL Allen modelled customer bill impacts [111]

Source: ACIL Allen Consulting, February 2019.

[111] ACIL Allen Consulting, South Australia New South Wales Interconnector, Updated Analysis of Potential Impact on Electricity Prices and Assessment of Broader Economic Benefits p. 16

5. Four credible options have been assessed, including new variants for interconnection to New South Wales

Summary points:

- This PACR has considered six variants of four credible options.
- We have revised the costs of the non-interconnector option (Option A) and the South Australia - Queensland option (Option B), following submissions.
- Two new variants for interconnection between South Australia and New South Wales have been considered.
- We have incorporated a new Buronga to Red Cliffs augmentation component in all interconnection options between South Australia and New South Wales, following assessment by AEMO.
- We have reduced the scope of the interconnection options between South Australia and Victoria (Option D), to reflect the concurrent Western Victoria Renewable Integration RIT-T currently being progressed by AEMO.

We have investigated variants of four credible options as part of the PACR assessment, comprising options involving new interconnectors between South Australia and the three neighbouring NEM states, as well as a predominantly local South Australian 'non-interconnector' option.

The options assessed differ from those considered in the earlier PADR following feedback from submissions, as well as further technical work by ElectraNet and market modelling by AEMO, and include two new variants. In particular:

- We have revised the costs of elements of the non-interconnector option (Option A), following further review and consideration of submissions. The scope of Option A remains the same as in the PADR.
- We have revised the costs and specification of the HVDC option between South Australia and Queensland (Option B) and included a mid-point converter station, following consideration of further information provided by ARCMesh.[112]
- We have also included a new HVDC variant for interconnection between South Australia and New South Wales including a mid-point converter station (new Option C.3.iii), given the revision in the assumed costs of adopting HVDC technology.
- We have assessed an additional option variant to C.3 for interconnection between South Australia and New South Wales that deviates from Buronga to Kerang and onwards to Darlington Point, as proposed in a submission from AusNet Services (new Option C.3.ii).

[112] See section 3.4.2 and Appendix G.

- We have incorporated a new Buronga to Red Cliffs augmentation component in all interconnection options between South Australia and New South Wales (Options C.3, C.3.ii and C.3.iii), following assessment undertaken by AEMO that demonstrates a positive incremental market benefit from including this investment.[113,114]

- We have reduced the scope of the interconnection options between South Australia and Victoria (Option D), to reflect the concurrent Western Victoria RIT-T being progressed by AEMO, and the ISP recommendation that the Western Victoria Group 1 augmentation should proceed without delay.[115]

- We are no longer considering option variants that involve series compensation (ie, Option 3i and Option 4i in the PADR), or the option for interconnection between South Australia and New South Wales via Darlington Point (Option C.4 in the PADR), as further technical assessment has identified alternatives that provide the same power transfer capability but avoid potentially restricting the connection of renewable generation to the series compensated line section.[116]

- We are no longer considering options for interconnection between South Australia and New South Wales that were shown in the PADR as having a substantially lower net market benefit (ie, Options C1 (second Murraylink), Option C.2 (275 kV) and Option C.5 (500 kV)). Adoption of AEMO's ISP assumptions and information provided in submissions have not introduced any new information that would be expected to materially change the relativity of net market benefits associated with these options.

- We have considered the scope for interim non-interconnector investments to be incorporated ahead of energising the preferred option.

Several submissions called for consideration for staged development of the options considered in this RIT-T, such as the development of the South Australian sections ahead of the New South Wales sections, or the development of lower capacity options initially. Table 6 summarises why we do not consider a staged development is feasible.

The options assessed in this PACR (and how they have changed since the PADR) are summarised in Table 3 and discussed in more detail in the remainder of this section. The additional option variants considered in the PADR but which have not been assessed in the PACR are discussed in section 5.6, together with the reasons these options are no longer considered credible options.

For completeness, section 5.7 presents the options that were considered earlier in the RIT-T process and not progressed, together with the reasons that these options are not considered credible.

Appendix I provides a disaggregated breakdown of the key cost components for each network option.

113 AEMO's assessment is presented in Appendix E.

114 A number of submissions also called for this to be included, see: AusNet Services, p. 5, MEA Group, p. 2 & South Australia Department for Energy and Mining, p. 46.

115 We have tested the sensitivity of the RIT-T outcome to this assumption, see section 8.5.

116 Arising from the potential risk of sub-synchronous oscillations and consequential damage to generators and network equipment connected to the series compensated line section.

Table 3 – Summary of the four credible options assessed in this RIT-T

Overview	Distance (km)[117]	Capital cost[118]	Annual contract cost	Notional Maximum Capability (MW)[119]		Change since the PADR
				Heywood	New interconnector	
'Non-interconnector' option						
Option A – Least cost non-interconnector option in South Australia	NA	$3m	$110m[120]	650	–	Cost of BESS elements revisited following submissions. Scope remains the same.
An interconnector to Queensland						
Option B – HVDC between north South Australia and Queensland	1,450	$1.98b	–	750[121]	700	HVDC costs reduced following submissions; new mid-point converter station added to support renewable energy connection
New South Wales interconnector options						
Option C.3 – 330 kV line between Robertstown South Australia and Wagga Wagga NSW, via Buronga, plus Buronga-Red Cliffs 220 kV line	916	$1.53b	–	750	800	Buronga-Red Cliffs 24 km 220 kV line component added, based on AEMO assessment demonstrating incremental net benefit. Further more detailed cost estimation has reduced costs of key components.

117 All distances are approximate. For the NSW options the km distance shown excludes the 24 km Buronga-Red Cliffs component, for clarity.

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

119 The notional maximum capabilities are not to be treated as additive due to network interactions. For example, the preferred option is modelled to deliver approximately 1,300 MW of combined transfer capacity.

120 This figure is for the central scenario and is the average over each year of the assessment period.

121 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)[117]	Capital cost[118]	Annual contract cost	Notional Maximum Capability (MW)[119]		Change since the PADR
				Heywood	New interconnector	
Option C.3ii – 330 kV line between Robertstown South Australia and Wagga Wagga NSW, via Buronga, Red Cliffs, Kerang and Darlington Point	1,016	$1.73b	–	750	800	**New option** via Kerang (Victoria), proposed in submission. Also includes 24 km Buronga-Red Cliffs 220 kV line component.
Option C.3iii – HVDC transmission between Robertstown SA and Darlington Point via Buronga; HVAC line between Darlington Point and Wagga Wagga NSW, plus Buronga-Red Cliffs 220 kV line	916	$1.64b	–	750	800	**New option** based on HVDC technology, in response to submissions. Also includes 24 km Buronga-Red Cliffs 220 kV line component.
A new interconnector to Victoria						
Option D – 275 kV line from central SA to Victoria	510[122]	$1.15b	–	750	650	Scope of option reduced to reflect concurrent Western Victoria RIT-T (ISP Group 1 project) – reduces cost of lines components.

[122] Includes the Horsham-Ararat replacement component (90 km).

All network options also include a Special Protection Scheme (SPS) to prevent cascaded tripping of the new interconnector or the Heywood interconnector following either the non-credible loss of either interconnector or a credible contingency following a planned outage of any line on either interconnector corridors.

The SPS will be designed to shed some load or generation along with some battery response, to keep the system in a secure operating condition and connected to the NEM system, following loss of either interconnector.

In the market modelling, combined interconnector power transfer limits have been applied to ensure that the loss of either interconnector will keep the remaining interconnector intact and allow the stable operation of the SA power system.

The scope of the SPS 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.

The credible options assessed are illustrated in Figure 7 below.

Figure 7 – Overview of the options (and variants) assessed[123]

While a stylised straight-line representation of interconnector routes has been included in the figure above for simplicity, detailed desk-top assessments have been undertaken to identify notional routes for each option. Indicative estimated costs of land and easement acquisition have been factored into the cost estimates for the various interconnector options based on this analysis.

---

123 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 capacities of these lines for ease of exposition.

We chose the 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 reasonably foreseeable operating conditions.

Under all new interconnector options, existing inertia and RoCoF constraints on the Heywood interconnector have been removed as the SA islanding risk is significantly diminished.

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 either the Heywood interconnector or the proposed interconnector. The South Australian power system will continue to benefit from connection to the NEM. Therefore, a shortage of inertia will only occur if a NEM-wide inertia shortage were to occur, which is not a factor influencing the outcomes of this RIT-T.[124]

5.1 Option A – Non-interconnector option

The PADR included a non-interconnector option that was based on advice from engineering consultants Entura, which took into account submissions from non-network proponents on the earlier PSCR. Entura developed a least cost non-interconnector solution for inclusion in the RIT-T assessment. The Entura report describing the least-cost non-interconnector option developed for the PADR is re-released alongside this PACR. The non-interconnector option was scoped to prevent a system black event that could occur from a loss of the existing Heywood interconnector as the initiating event.

We received a number of submissions on the non-interconnector option in response to the PADR. We engaged Entura to review the points raised in these submissions, and to advise on whether and how the non-interconnector option should be revised in response.

In particular, Entura reviewed the scope of the components included in Option A in response to points raised by parties in submissions. The conclusion of this was that the PADR scope remained appropriate and more detail can be found in Appendix C.

Separately we have also undertaken further costing analysis in relation to the battery components of the non-interconnector option, which has resulted in a downwards revision to the costs of the BESS components of the option. Specifically, we have taken into account the opportunities for additional revenue streams for the BESS component in further refining the costs, which have now reduced by approximately 15 per cent.

Following this further work, the key components of the least cost non-interconnector solution considered in this PACR, and the aggregate average annual cost of this solution (under the central scenario) are set out in Table 4 below.

We note that the costs for the majority of components for Option A have been estimated on the basis of prices set out in responses by non-network proponents to the earlier PSCR.

[124] In some scenarios, inertia in NSW falls below the level required to sustain a NSW island. Whilst this is an unlikely outcome, ElectraNet has estimated the costs of providing inertia from synchronous condensers and considers that a solution can be reasonably implemented.

These prices are commercial-in-confidence and therefore have not been disaggregated in this PACR (or the earlier PADR). Two of the non-network proponents who submitted those prices have continued to engage with us and made submissions to the PADR which have not altered the prices at which they have said they are prepared to provide these solutions.

Table 4 – 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)	Confidential	Confidential	Confidential	Confidential
Osborne cogeneration				
Solar thermal at Davenport				
BESS – Tailem Bend				
Murraylink (Transfer of FCAS)				
BESS (location to be determined)				
Minimum load control				
Total combined cost	**$110**[125]	**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.

As noted in the PADR, the non-interconnector solution includes a number of risks and uncertainties that have not been fully accounted for in this RIT-T assessment. The key ones, as highlighted by Entura at the PADR stage, continue to be:

- the non-interconnector option does not meet the defined minimum system performance levels under all conditions;
- 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; and
- the continued growth in rooftop PV installations is leading to the minimum grid demand approaching zero in the mid-2020s (refer to section 5.1 of the PADR).

Fully accounting for these factors would increase the cost of this option further.

125 This figure is for the central scenario and is the average over each year of the assessment period.

5.2 Option B – HVDC between northern South Australia and 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:

- HVDC converter stations including converter transformers at Davenport and Western Downs;
- a HVDC converter station at Broken Hill including converter transformers, to enable renewable generation (wind and solar) to be connected around Broken Hill;
- augmentation of existing substations at Davenport, Broken Hill and Western Downs;
- a new HVDC line from Davenport to Western Downs via Broken Hill; and
- a Special Protection Scheme (to detect and manage loss of either interconnectors).

Strong connection nodes at both ends means that there would be reduced risk of constraints over the interconnector under Option B.

We have undertaken further assessment of the potential cost of HVDC lines and commissioned assessment by independent engineering consultants Jacobs. This review has concluded that a reduction in the estimated cost of HVDC lines is appropriate.

Capital costs for this option are estimated to be in the order of $1,980 million. This estimate has been revised since the PADR to reflect:

- Further investigation into likely HVDC transmission line costs, in response to submissions received on the earlier PADR.[126] This has had the impact of decreasing the cost estimates for the HVDC line from $1,040 million in the PADR to $970 million in this PACR.
- The inclusion of a new mid-point converter station as part of the option specification (which increases the cost of this option). Assessment since the PADR has highlighted that for this option to facilitate connection of renewable generation and provide benefits associated with avoided REZ transmission capex, it needs to include mid-point converter stations. These converter stations are estimated to cost $280 million each (which has been sourced directly from manufacturers of converter stations).

Overall these changes have resulted in an increase in the cost of this option of approximately $180 million since the PADR.

[126] In particular a submission from ARCMesh, discussed in section 3.4.2 and Appendix G.

While a new mid-point converter station has been included to enable this option to capture the benefits of connecting REZs (and avoiding/reducing the associated transmission capital costs that would be incurred otherwise) in response to submissions, the assessment finds that this is actually net negative. Specifically, these estimated benefits for Option B are in the order of $75 million, which is less than the cost of the mid-point converter station required to generate them ($280 million). Section 8 outlines how if both this cost and benefit are removed from the assessment of Option B, the estimated net market benefits increase (from $50 million to $350 million) but it does not affect identification of the preferred option.

In assessing Option B, we have taken into account the QNI limit improvements as advised by Powerlink with this option in-place. The separate PACR Market Modelling Report provides detail on the exact limit interactions assumed.

Construction is expected to require two to three years, with energisation possible by the end of 2023, subject to obtaining necessary environmental and development approvals.

5.3 Option C – New interconnection between South Australia and NSW

The PADR identified new interconnection between South Australia and New South Wales via Buronga as the option that satisfied the RIT-T. This finding has been confirmed by the assessment AEMO has conducted for the ISP.

The PADR flagged that there were a number of aspects of the options to New South Wales that require further investigation to refine the scope, including the compatibility of fixed series compensation with the connection of new renewable generation and the potential benefits of strengthening the link between Buronga in New South Wales and Red Cliffs in Victoria. The options included in this PACR reflect this additional analysis. It is expected that the project scope will be further refined during project detailed design and delivery.

The PACR assessment has considered three option variants relating to new interconnection between South Australia and New South Wales, via Buronga. Two of these variants are new and have been developed in response to submissions on the PADR.

Several submissions suggested that a potential staged implementation of the preferred option should be examined, and in particular one that optimises the timing of the NSW components of the investment.[127] We do not consider such staging of investment between South Australia and New South Wales to be feasible, as the expected near-term benefits accruing in South Australia would not be realised in the absence of the investment in New South Wales.[128]

[127] PIAC, p. 2, SACOSS, p. 2 and The Energy Project, p. 6.

[128] Our consideration of the potential for staging is set out in section 4.4 as well as Appendix F which responds to the points made in The Energy Project submissions.

These options are scoped to provide 800 MW of transfer capacity and to increase transfer capacity on the existing Heywood interconnector to 750 MW, while delivering combined transfer capacity modelled at 1,300 MW. This is in addition to the existing transfer capacity of Murraylink (approximately 200 MW) which is 'firmed up' by the augmentation associated with these options.

5.3.1 Option C.3 – 330 kV line between Robertstown in South Australia and Wagga Wagga in NSW, via Buronga

Option C.3 involves constructing a new 330 kV line between the mid-north region of South Australia and Wagga Wagga in New South Wales, via Buronga with an augmentation between Buronga and Red Cliffs in Victoria. The indicative route investigated runs approximately 916 km from Robertstown in South Australia via Buronga in New South Wales and through to Wagga Wagga, including 24 km line from Buronga to Red Cliffs in Victoria. This option is assumed to provide 800 MW of transfer capacity.

The key components of this option are as follows:

- a new 330 kV double circuit line between Robertstown and Buronga;
- a new 330 kV double circuit line between Buronga and Darlington Point;
- a new single circuit 330 kV line between Darlington Point and Wagga Wagga;
- a new 330 kV substation at Robertstown, including two 275/330 kV transformers at Robertstown;
- new 330 kV Phase Shift Transformers at Buronga (in order to share power transfers between new and existing interconnectors);
- two 330/220 kV transformers at Buronga;
- augmentation of existing substations at Robertstown, Buronga, Darlington Point, Wagga Wagga and Red Cliffs;
- a new double circuit 220 kV line (conductor strung on one side and operated as a single circuit) from Buronga to Red Cliffs in Victoria;[129]
- turn in the existing 275 kV line between Robertstown and Para into Tungkillo;
- static and dynamic reactive plant at Robertstown, Buronga and Darlington Point; and
- a Special Protection Scheme (to detect and manage loss of either interconnectors).

[129] Appendix E summarises the economic assessment undertaken by AEMO regarding implementing the Red Cliffs to Buronga augmentation, which includes their assessment that having this strung as a double circuit line will provide additional net market benefits over a single circuit line by allowing future expansion.

This option remains as specified in the PADR, with the exception of the addition of a new 24 km 220 kV line from Buronga to Red Cliffs in Victoria.[130] The PADR flagged that the addition of this component would facilitate the connection of additional solar capacity in western Victoria, providing increased access to the Sydney and Adelaide load centres.

The addition of this component has now been assessed by AEMO to provide an incremental net market benefit. AEMO's assessment is presented in Appendix E. The results of the RIT-T assessment presented in section 9 for this option have been derived on the basis of including this component.

Further technical assessment has confirmed that the addition of the Buronga-Red Cliffs augmentation, together with minor changes in the network configuration around the Buronga to Darlington Point corridor and relying on a reasonable level of load shedding following the non-credible loss of either interconnector, will maintain the combined capacity of the existing Heywood interconnector and new interconnector as per the preferred option in PADR, without the need for series compensation.

The effective South Australian import capacity across both interconnectors under this option is therefore 1,300 MW.[131]

Capital costs for this option are estimated to be in the order of $1,530 million, which includes the cost of the additional Buronga-Red Cliffs 220 kV component. Specifically,

- the cost of the main option components has increased from the earlier PADR estimate for Option C.3 to $1,485 million (an increase of $50 million), following further detailed cost estimation; plus
- the cost of the additional Buronga- Red Cliffs 220 kV component is estimated at $46 million.

On balance, the cost estimate for this option is $96 million higher than that assumed in the PADR for Option C.3, ie, a seven per cent increase.

Construction is expected to require approximately two years with energisation possible between 2022 and 2024, subject to obtaining necessary environmental and development approvals. The economic assessment for this PACR assumes a 1 July 2023 energisation date.

However, as discussed earlier, the South Australian Government has provided funding to allow preliminary works for this option to be expedited, which increases the likelihood of achieving a 2022 delivery date.

5.3.2 Option C.3ii – 330 kV line between Robertstown in South Australia and Wagga Wagga in NSW, via Buronga, Kerang (Victoria) and Darlington Point

Option C.3ii is a new option that has been included in the PACR assessment following a submission from AusNet Services.

---

130 Turning the existing 275 kV line between Robertstown and Para into Tungkillo is also new since the PADR, but has a minor cost associated with it (approximately $5 million).

131 The PADR analysis had assumed a combined constraint of 1,150 MW under this option.

This option is a variant of the above 330 kV option that increases interconnection between Robertstown SA and Wagga Wagga in New South Wales via Buronga, but which is also routed via Kerang in Victoria and Darlington Point in New South Wales. This routing potentially enables the unlocking of renewable generation resources at the bottom of the Murray River REZ area, rather than the top.

The indicative route investigated runs approximately 1,016 km from Robertstown in South Australia via Buronga in New South Wales and then through Kerang in Victoria and Darlington Point and through to Wagga Wagga, including 24 km line from Buronga to Red Cliffs in Victoria. This option is assumed to provide 800 MW of transfer capacity.

This option also incorporates an upgrade of the 220 kV line from Buronga to Red Cliffs in Victoria.

The key components of this option are as follows:

- a new 330 kV double circuit line between Robertstown 330 kV and Buronga 330 kV;
- a new 330 kV double circuit line between Buronga and Kerang;
- a new 330 kV double circuit line between Kerang and Darlington Point;
- a new single circuit 330 kV line between Darlington Point and Wagga Wagga;
- a new 330 kV substation at Robertstown including two 275/330 kV transformers at Robertstown;
- new 330 kV Phase Shift Transformers at Buronga (in order to share power transfers between new and existing interconnectors);
- two 330/220 kV transformers at Buronga;
- a new 330/220 kV transformer at Kerang;
- augmentation of existing substations at Robertstown, Buronga, Darlington Point, Wagga Wagga, Kerang and Red Cliffs;
- a new double circuit 220 kV line (conductor strung on one side, operated as a single circuit) from Buronga to Red Cliffs in Victoria;[132]
- turn in the existing 275 kV line between Robertstown and Para into Tungkillo;
- static and dynamic reactive plant at Robertstown, Buronga, Kerang and Darlington Point; and
- a Special Protection Scheme (to detect and manage loss of either interconnectors).

[132] Appendix E summarises the economic assessment undertaken by AEMO regarding implementing the Red Cliffs to Buronga augmentation, which includes their assessment that having this strung as a double circuit line will provide additional net market benefits over a single circuit line by allowing future expansion.

Capital costs for this option are estimated to be in the order of $1,730 million. Construction is expected to require approximately two years with energisation possible between 2022 and 2024, subject to obtaining necessary environmental and development approvals.

The economic assessment for this PACR assumes a 1 July 2023 energisation date. As for Option C.3, the funding for preliminary works provided by the South Australian Government may enable earlier energising of parts of this option.

5.3.3 Option C.3iii – HVDC transmission between Robertstown in South Australia and Darlington Point and Wagga Wagga in NSW, via Buronga

Option C.3iii is also a new option that has been included in the PACR assessment following submissions that highlighted the potential for the costs of HVDC lines to be lower than had been assumed in the PADR.

As noted in section 5.2 above, we have undertaken further assessment of the potential cost of HVDC lines and commissioned an assessment by independent engineering consultants Jacobs. This review has concluded that a reduction in the estimated cost of HVDC lines is appropriate. In light of this, and the interests expressed in HVDC technology more broadly, we have included a variant of Option C.3 that utilises an HVDC link for the Robertstown – Darlington Point portion of the investment.

The key components of this option are as follows:

- a new 400 kV HVDC line between Robertstown and Darlington Point;
- a new single circuit 330 kV line between Darlington Point and Wagga Wagga;
- HVDC converter stations including converter transformers at Robertstown and Darlington Point;
- a mid-point HVDC converter station including converter transformers at Buronga, in order to enable the connection of renewable generation;
- augmentation of existing substations at Robertstown, Buronga, Darlington Point, Red Cliffs and Wagga;
- a new double circuit 220 kV line (conductor strung on one side and operated as a single circuit) between Buronga and Red Cliffs in Victoria;[133]
- turn in the existing 275 kV line from Robertstown to Para into Tungkillo; and
- a Special Protection Scheme (to detect and manage loss of either interconnectors).

[133] Appendix E summarises the economic assessment undertaken by AEMO regarding implementing the Red Cliffs to Buronga augmentation, which includes their assessment that having this strung as a double circuit line will provide additional net market benefits over a single circuit line by allowing future expansion.

As with the case of the HVDC South Australia – Queensland interconnector option (Option B), a mid-point converter station would need to be included within this option in order to facilitate the connection of renewable generation. Without this element, the benefits associated with the development of additional renewable generation and the avoidance of associated REZ transmission would not be obtained.

Capital costs for this option are estimated to be in the order of $1,640 million. Construction is expected to require approximately two years with energisation possible between 2022 and 2024, subject to obtaining necessary environmental and development approvals.

The economic assessment for this PACR assumes a 1 July 2023 energisation date. Again, the funding for preliminary works provided by the South Australian Government may enable earlier energising of parts of this option.

5.4 Option D – 275 kV line between central South Australia and Victoria

Option D utilises a connection from Tungkillo in South Australia to 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 between Tungkillo in South Australia to Horsham in Victoria, and then an additional 90 km between Horsham and Ararat.

The PADR flagged the interaction between this option and the investments being considered by AEMO in relation to Western Victoria Renewable Integration which include increasing interconnection between the Melbourne load centre and Ararat in Western Victoria.

A RIT-T is currently being applied to this investment by AEMO and a PADR was released in December 2018, which includes the full cost of this augmentation. The Western Victoria augmentation has also been identified in the ISP as a Group 1 project.[134]

As a consequence, we have assumed that the network investment identified in the ISP associated with Western Victoria Renewable Integration proceeds in the base case. This reduces the scope and costs of the additional investment required under Option D, compared with that assumed in the PADR. We have however also considered as a sensitivity the impact of the Western Victoria investment not proceeding (see section 8.5.2).

The key components of this option are therefore now as follows

- a new double circuit 275 kV line between Tungkillo and Horsham;
- two 275/220 kV Phase Shifting Transformers at Horsham (in order to share power transfers between new and existing interconnectors);

[134] The COAG Energy Council requested the ESB to report to the December 2018 meeting on how the Group 1 ISP projects can be implemented and delivered as soon as practicable and with efficient outcomes for consumers.

- replacing the existing Horsham to Ararat single circuit 220 kV line (including all sections in-between) with a double circuit 220 kV line;
- augmentation of existing substations at Tungkillo, Horsham and Ararat;
- turn in the existing 275 kV line from Robertstown to Para into Tungkillo;
- static and dynamic reactive plant to Tungkillo, Tailem Bend and Horsham;
- a Special Protection Scheme (to detect and manage loss of either interconnectors); and
- additional domestic generation capacity[135] in South Australia to manage the potential loss of both interconnectors in one event – most likely a bushfire around Tungkillo in South Australia or Ballarat in Victoria.

A maximum transfer capacity of 650 MW has been assessed for Option D. This is due to the existing capacity of Heywood (ie, 650 MW) and needing to be able to cater for the loss/tripping of either interconnectors.

Further technical assessment has confirmed that this option is able to overcome constraints on the combined capacity of the existing Heywood interconnector and a new interconnector, without the need for series compensation. The effective capacity across both interconnectors under this option is therefore 1,100 MW.[136]

We have also continued to incorporate the costs of 'network hardening' to reflect the operational risks associated with this bushfire prone region.[137] A severe bushfire could lead to coincident and wide spread damage to both the existing Heywood interconnector and a new interconnector, with extended time period to bring it back into service.

Further, this raises the prospect that an outage of both interconnectors could be reclassified by AEMO as a credible contingency.[138]

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) that would leave South Australia no worse off than it is today if South Australia were to be islanded.

Capital costs for this option are estimated to be in the order of $1,150 million, comprised of:

- $850 million for the network component; and
- $300 million for network hardening.

[135] This has been reflected based on the costs of an OCGT plant in South Australia, as described further above.

[136] The PADR analysis had assumed a combined constraint of 950 MW under this option.

[137] AusNet Services questioned the need for these network hardening costs. We have set out our response to the concerns raised in section 4.3.3.

[138] 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.

Overall, the costs of this option have remained unchanged since the PADR.

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

5.5 Interim non-interconnector investments

Following submissions on the PADR, ElectraNet has engaged Entura to investigate the opportunity for non-network solutions to help ensure satisfactory network performance (in terms of inertia, RoCoF and FCAS) for the current network arrangement during the interim period before the energisation of a new interconnector. This consideration has been in addition to the new synchronous condensers ElectraNet is procuring to address a system strength shortfall.

ElectraNet is addressing the declared system strength gap outside of this RIT-T process. We have recommended to AEMO that the installation of four large synchronous condensers will meet the immediate system strength requirement. The proposed system strength solution will enable the South Australian power system to be operated without directing synchronous generators on for system strength purposes. This system strength solution is also expected to alleviate renewable generation caps in place in South Australia, which will be further alleviated when the new interconnector has been energised.

Entura have considered additional support in the form of heavier synchronous condensers, additional synchronous condensers and additional batteries. Entura found that there is some value in considering additional support for the interim period but that this value is mainly indirect through providing redundancy and operational flexibility.

Given that the proposed system strength solution is expected to alleviate renewable generation caps in place in South Australia, we consider there is not a clear need to include interim non-interconnector components before a new interconnector is energised. We acknowledge there may be a role for these solutions to further increase net market benefits in combination with increased interconnection. Any such consideration will be undertaken through a separate process.

A full discussion of this assessment of interim non-interconnector components, including the additional support considered, can be found in the Entura report, being released alongside this PACR.

5.6 Options in the PADR that are no longer considered credible

The PADR assessment included six additional option variants which have not been included in this PACR, as they are no longer considered to be credible options.

Three of these earlier variants are either no longer considered to be technically feasible (Option C.4) or are no longer considered to be separate, viable variants (Options C.3i and Option Di), following further technical assessment.

The PADR assessment of a further three variants (Option C.1, C.2 and C.5) demonstrated that these options had a substantially lower net market benefit than the other options considered, across all scenarios. There is no reason to expect that this finding would change in the PACR assessment. There was no new information provided in submissions that would materially change the assessment of these options.

The key change between the PADR and PACR wholesale market modelling assessment relates to the modelling of benefits associated with avoided REZ transmission investment. These benefits either do not apply to these options (Option C.1 and C.2) or would not be of an order of magnitude to influence the earlier PADR outcome (Option C.5).

The other change in the modelling relates to the South Australian gas-fired generator assumptions, which is also not expected to alter the relativities between the South Australia – New South Wales variants. The time and resources required to continue to model these option variants is therefore not proportionate to the expected outcome of the RIT-T analysis, and we have concluded from the earlier analysis that these options are not economically viable.

Discontinuing consideration of these options has enabled us to instead focus our assessment on additional variants of those options that were found to be more credible in the PADR assessment.

Table 5 – Options included in the PADR which are no longer considered credible

Description	Reason for exclusion for PACR assessment
Option C.1 – New DC link from Riverland SA to NSW (‘Murraylink 2’)	PADR assessment showed low or negative net market benefit. This option was proposed in a submission to the PSCR, but there were no supporting submissions following the PADR assessment.
Option C.2 – 275 kV line from Robertstown in SA to Wagga Wagga NSW, via Buronga	PADR assessment showed substantially lower net market benefit than for other options. The refinements to the market modelling in the PACR to better capture benefits associated with avoiding transmission investment associated with REZs would not change this outcome, as these benefits would not accrue to the 275 kV option as much as the 330 kV option whilst increasing benefits associated with the 330 kV options.

Description	Reason for exclusion for PACR assessment
Option C.3i – 330 kV line from Robertstown in SA to Wagga Wagga NSW, via Buronga, plus series compensation (or similar)	Further technical assessment has confirmed[139] that the addition of series compensation may restrict the connection of renewable generation due to technical consideration, reducing benefits associated with renewable energy development. Specifically, 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. This assessment has also identified that series compensation is no longer needed in order to reduce constraints on the combined operation of the Heywood interconnector and a new interconnector, due to changes in proposed network configuration under this option and with reasonable levels of load shedding. In effect, this option has become redundant, with the benefits now being captured directly by Option C.3.
Option C.4 – 330 kV line from Robertstown in SA to Wagga Wagga NSW, via Darlington Point	Further technical assessment has shown that bypassing Buronga on route to Darlington Point would not capture benefits associated with avoided REZ transmission, and would also have a higher cost associated with the requirement to include an additional switching station to manage system technical performance.
Option C.5 – 500 kV line from Northern SA to east NSW	PADR assessment showed low or negative net market benefit associated with this option, driven by its substantially higher cost. The refinements to the market modelling in the PACR to better capture benefits associated with avoiding transmission investment associated with REZs would not be expected to fundamentally alter this outcome, given the magnitude of the option cost.
Option Di – 275 kV line from central SA to Victoria plus series compensation (or similar)	Consistent with Option C.3i, further technical assessment has confirmed that the addition of series compensation would restrict the connection of renewable generation, reducing benefits associated with renewable energy development. This assessment has also identified that series compensation is no longer needed in order to reduce constraints on the combined operation of the Heywood interconnector and a new interconnector. In effect, this option has become redundant, with the benefits now being captured directly by Option D.

[139] ElectraNet noted in the PADR that this may be an outcome of series compensation, and further analysis has confirmed this to be the case.

5.7 Other options previously considered but not progressed

A range of other options have also been considered by ElectraNet over the course of this RIT-T, both at the initial PSCR stage[140] and as part of the detailed pre-screening assessment of potential credible options undertaken between the PSCR and PADR.[141]

The table below summarises the key findings from these assessments.

Table 6 – Other options previously considered but not progressed

Description	Reason for exclusion from the RIT-T assessment
New interconnectors with significantly greater capacity than the existing Heywood interconnector	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.[142] This led to the majority of the interconnector options in the PADR being assumed to be between 600-800 MW.
HVAC to Queensland	For interconnection to Queensland, the long distance dictates the use of HVDC as the preferred transmission technology, even with the added expense of DC converter stations, due to its expected lower cost overall.
Single circuit 275 kV and 330 kV to NSW	Capacity limits of single circuit 275 kV and 330 kV lines mean that a line of one of these voltages was considered to not be technically feasible at any cost.
HVDC line from northern South Australia to east NSW	A DC line from northern South Australia to east NSW was considered to be highly inflexible and expensive to connect/cut into.
HVDC to Victoria	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.
HVAC to Victoria of capacity greater than 275 kV	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.
Staging of investment for all interconnector options	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 than the initial cost of stringing one-side (the logistics of live-line stringing a

140 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.

141 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.

142 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.

Description	Reason for exclusion from the RIT-T assessment
	second line would also be more complex, and have a significant cost). In addition, 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.
Further increases to the Heywood Interconnector capacity	ElectraNet investigated the ability of expanding the Heywood Interconnector capacity in order to meet the identified need. Two options were considered, the "Krongart Option" from the earlier Heywood augmentation RIT-T and a further incremental option of adding further reactive support along the existing Heywood Interconnector corridor. Neither of these options mitigate the risk of a separation event occurring, or the magnitude of the impact of that event in terms of unserved energy. Specifically, these options are susceptible to the same drivers for separation events considered as part of this RIT-T (eg, bush-fires, storms, etc.) and are anticipated to worsen the expected unserved energy due to the relationship between interconnector flows and the risk of severe disruption in South Australia during a separation event. ElectraNet therefore considers this option is unable to meet the system security component of the identified need for this RIT-T.
Connection to other jurisdictions	Connections to other jurisdictions such as Tasmania and Western Australia have not been considered as credible due to the large relative distances when compared to other alternatives.

6. Estimating net market benefits

Summary points:

- We continue to use market modelling to estimate key categories of net market benefit.
- This now includes direct modelling of the benefit associated with avoiding REZ transmission costs.
- Our modelling inputs have been updated and generally align with the ISP except for gas prices and emissions reduction targets, where we have considered a wider spread of potential future outcomes in order to fully stress-test the analysis.
- We have undertaken extensive sensitivity testing around key variables (including those in the ISP).

The RIT-T requires many of the 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.[143]

We performed detailed market modelling in PLEXOS[144] to assess the market benefits of the various credible options over three future scenarios as well as a number of sensitivities.

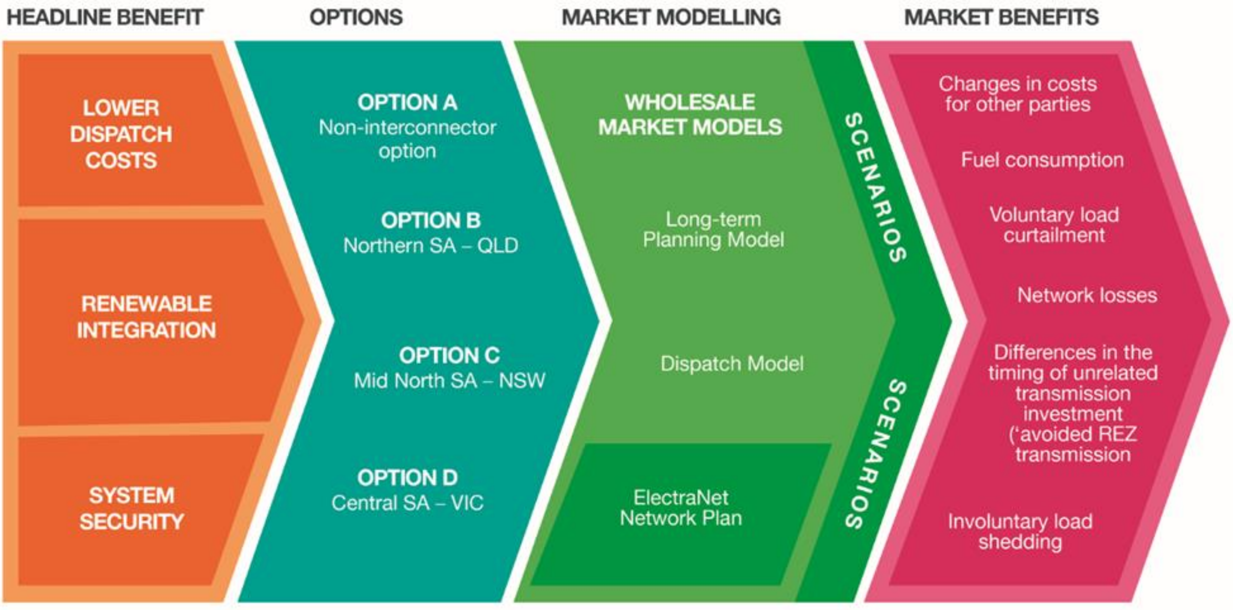
6.1 Overview of the market modelling

A high-level summary of the market modelling is illustrated in the figure below.

[143] 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.

[144] PLEXOS is a market modelling software commonly used in the electricity sector.

Figure 8 – Overview of the market modelling



There are three key components of the market modelling – the long-term expansion model, the time sequential dispatch model and the network representation.

The market modelling approach was described in the earlier PADR (and associated market modelling report). In response to requests from stakeholders for further detail, we have also provided an expanded description in the market modelling report published alongside this PACR, to continue to provide transparency to market participants.

6.2 Market benefit categories calculated using market modelling[145]

Each new interconnector option has the following impact on market outcomes:

- a 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 (particularly in South Australia), 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 and to connect new renewable generation in NSW to avoid the higher costs associated with gas generation in NSW, as NSW black coal plant retires;

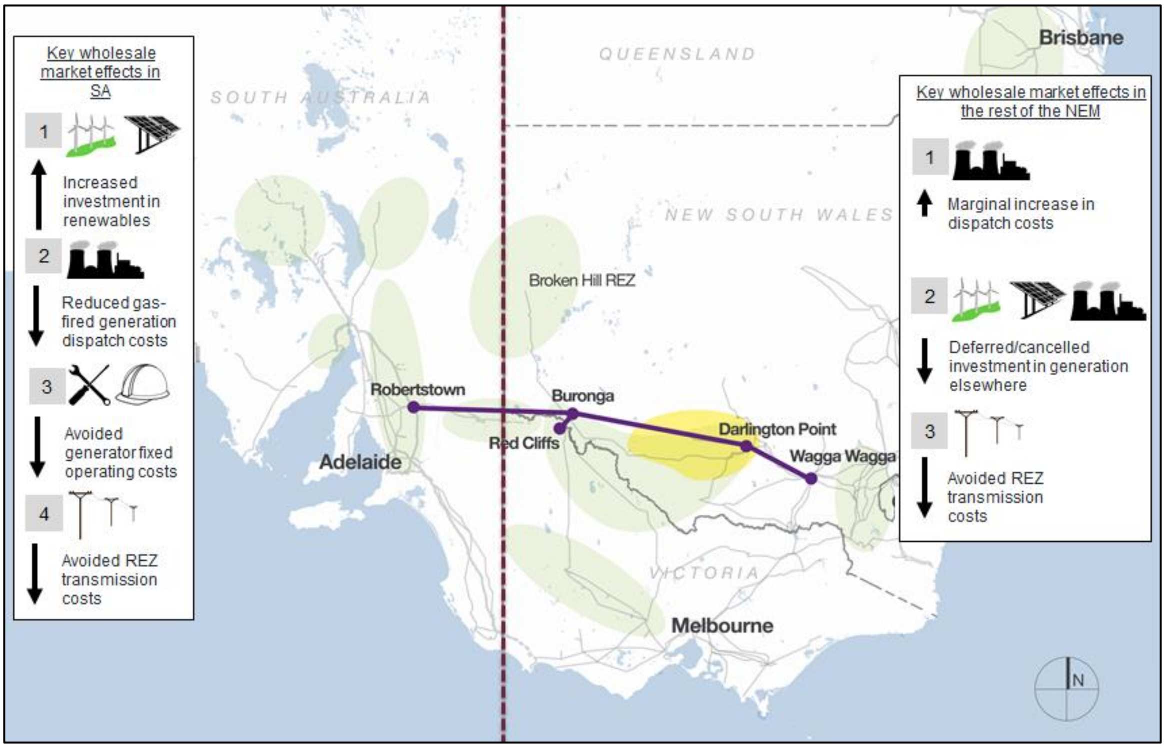
[145] The PADR provides an expanded discussion of each of the benefit categories estimated using market modelling, which has not been repeated here.

- 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 potentially offset by increased investment in renewable generation capacity in South Australia.
- allows development of some of the REZs identified by AEMO in the ISP (for all options except South Australia to Victoria), avoiding the need for additional intra-regional transmission investment that would otherwise be required by the mid-2030s to enable this development. This provides a benefit reflecting the difference in timing of unrelated transmission investment.

There is a possibility that the Queensland option (Option B) will defer the need for the QNI Stage 2 upgrade highlighted in the ISP. We find that this outcome actually *reduces* the estimated net market benefits for this option, compared to the case where the QNI Stage 2 upgrade remains unaffected and so have included it as a sensitivity (presented in section 8.5.1).

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

Figure 9 – Illustrative summary of key wholesale market effects – using Option C.3 as an example



The approach taken to estimating each of these market benefit categories was discussed in the PADR and also in the earlier PADR market modelling report. The PACR market modelling report being released alongside this PACR provides further details, where requested in submissions.

The classes of market benefit which we consider not to be material for this RIT-T remain the same as for the PADR and are set out in Appendix D.

The scope of the RIT-T 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 Changes to the modelling assumptions and approach since the PADR

There have been a number of changes made to the modelling (and in particular the assumptions adopted), to reflect continuing changes in market and regulatory arrangements, as well as to address comments made in response to the PADR.

The most material changes in assumptions are:

- An updating of all assumptions to reflect those adopted by AEMO in the ISP and the 2018 Electricity Statement of Opportunities (ESOO).[146]
  - In response to submissions, the PACR now aligns all generator input assumptions with the ISP input assumptions, including the minimum operation of South Australian gas plant (although we have also undertaken sensitivity testing around these assumptions, as outlined in section 4.1.1 above).
  - The key exceptions are emissions targets and gas prices, where we have adopted assumptions in the high and low scenarios[147] that represent a wider spread of potential future outcomes, compared to those used in AEMO's core scenarios in the ISP – in order to fully stress-test the analysis.
- A fully integrated assessment of the benefits associated with deferral of transmission investment that the ISP projects would otherwise be required to unlock priority REZs.
  - The PADR adopted an approach that integrated AEMO's ISP findings in relation to these benefits with our PLEXOS modelling.[148] In this PACR, the REZ developments identified by AEMO in the ISP have now been reflected in the network representation used for the market modelling, which enables the associated transmission deferral benefits to be estimated as an outworking of our market model. For some options this has resulted in a change in the extent of this benefit, compared to the earlier PADR. The accompanying market modelling report presents more detail on the approach we have adopted.

---

[146] This was raised by Engie's submission to the PADR (p. 2) in relation to Solar PV and battery penetration projections.

[147] Specifically we have continued to adopt higher and lower assumed gas prices than the ISP in our high and low scenarios, and have also continued to test a 'no further emission reduction target' in our low scenario.

[148] This approach was adopted as a result of the over-lapping timeframes for publication of the PADR and the ISP. However the PADR flagged our intention to integrate this analysis as part of the PLEXOS modelling in the PADR.

   - This has necessitated the use of a 'multiple-block' methodology for the wholesale market modelling,[149] while the PADR used a 'one-block' methodology to approximate the wholesale market effects.[150]

- Applying the current South Australian Government inertia requirement (ie, the 3 Hz/s) to all scenarios investigated (including the high scenario, which previously reflected a higher 1 Hz/s standard).

- The wholesale market modelling assumptions have been updated to reflect cycling constraints on gas generators, which was a point raised in submissions;

- We have amended our assumption on the scope for potential transmission investment deferral under a new SA-Queensland interconnector, to deferral of Stage 2 of the QNI upgrade only ($560 million).[151] This reflects identification by AEMO in the ISP of Stage 1 of the QNI upgrade as a Group 1 project which should be pursued immediately.

   - In addition, we have now considered this deferral as a sensitivity test, rather than including it in our core analysis due to being found to deliver a net cost (as outlined in section 8.5.1).

- Additional sensitivities have been run to reflect feedback in submissions in relation to key assumptions adopted in the model:

   - This includes higher than anticipated NSW coal prices, different assessment periods, lower costs for non-interconnector support, lower avoided transmission costs associated with connecting REZs and the interaction with the coincident Western Victoria Integration RIT-T. The results of these sensitivities are presented in section 8.5.

There is continuing uncertainty in relation to future emissions and reliability policies in the NEM, with the National Energy Guarantee (NEG) policy no longer being Federal Government policy, albeit that the reliability component of the NEG may form part of an alternative future policy.

---

149 The granularity of the modelling methodology is driven by the interaction with modelling the benefits associated with deferral of transmission investment that the ISP projects would otherwise be required to unlock priority REZs. In particular, when these benefits are explicitly modelled (as they are in the PACR), the computational requirements necessitate using a 'multiple-block' methodology approach to approximate the wholesale market effects. A 'multiple-block' methodology is where long-term planning modelling is conducted for number of periods that, together, cover the entire assessment period and differs to a 'one-block' methodology where this modelling is conducted for the entire assessment period (which was able to be used in the PADR since the avoided REZ transmission cost benefits were not explicitly modelled).

150 This approach was adopted in the PADR as a result of the over-lapping timeframes for publication of the PADR and the ISP. The different approaches taken to modelling these benefits is discussed further in section 6.3.

151 The PADR analysis assumed that would defer the timing of unrelated transmission investment of $560 million in a QNI Upgrade from 2023 until 2040. The $560 million has been sourced from: TransGrid & Powerlink, *Expanding NSW-QLD transmission transfer capacity*, Project Specification Consultation Report, November 2018, p. 26.

Notwithstanding the uncertainty about the specifics of future policies, the modelling for this RIT-T includes a constraint on overall emission levels that reflects Australia's COP 21 commitments in the central scenario (and tests alternative emissions reduction targets in the high and low scenarios), as well as a constraint on generation planting to ensure that the NEM reliability standard is met in all future periods.[152]

This approach is consistent with that adopted by AEMO in the ISP, and focuses on the outcomes that future policies need to deliver in order to comply with existing emission levels and reliability commitments in a least cost manner, rather than the mechanism used to deliver those outcomes.

The PACR also includes a benefit associated with network capital cost deferral, which was not included in the PADR but captures the interaction between the interconnector options and two unrelated network investments that ElectraNet expects to have to undertake in the base case (namely, a turn in at Tungkillo and substation works at Robertstown).[153]

Additional network modelling undertaken since the PADR has identified that each interconnector option has minor timing (deferral) implications for these two investments, compared to the base case. The estimated market benefits are not materially different across the options (ranging from $3 million to $10 million in PV terms).

6.4 General modelling parameters

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

While the capital components of the credible options have asset lives extending beyond 2040, the modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life.

The length of the assessment period was commented on by a number of parties in submissions to the PADR. However, we do not consider that any of the material presented warrants a change to the assessment period, and that the 21-year period remains appropriate.

We discuss these points and the rationale for the assessment period selected in section 4.5.1 above. We have also undertaken additional robustness testing, which shows that adoption of a shorter assessment period would not alter the preferred option.

We also continue to adopt 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.

---

152 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.

153 The non-interconnector option does not affect the timing of these two unrelated investments.

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. We have also identified the 'boundary value' beyond which the choice of discount rate would affect identification of the preferred option.

A number of parties commented on the discount rates used in the PADR assessment. We discuss each of these issues, and our responses, in section 4.5.2 above.

7. Scenario analysis and sensitivity testing

Summary points:

- The RIT-T assessment considers three reasonable scenarios, which differ in relation to demand outlook, assumed gas prices, assumed emissions targets and generator capital costs.
- The scenarios reflect a broad range of potential outcomes across the key uncertainties that are expected to affect the future market benefits of the investment options being considered.
- We have also undertaken a wide range of sensitivity tests in order to test the robustness of the outcome to key uncertainties.

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 adoption of different scenarios tests the robustness of the RIT-T assessment to different assumptions about how the energy sector may develop in the future.

The robustness of the outcome is also investigated through the use of sensitivity analysis in relation to key input assumptions. We have expanded the sensitivity analysis in the PACR in response to comments in submissions.

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

7.1 The RIT-T assessment considers three ‘reasonable scenarios’

The RIT-T is focused on identifying the top ranked credible option in terms of expected net market benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future ‘states of the world’).

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net market benefit.[154] It is this 'expected' net market benefit that is used to rank credible options and identify the preferred option.

Consistent with the approach in the earlier PADR, 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.

The table below provides an overview of the three scenarios considered.

Table 7 – Overview of scenarios considered

Central Scenario	Low Scenario	High Scenario
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	Reflects a state of the world with low gas prices, low demand and no emissions reduction targets over and above the existing LRET	Reflects a state of the world with high gas prices and high demand, alongside aggressive emissions reduction targets

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

The scenarios differ in relation to demand outlook, assumed gas prices, assumed emissions targets and generator capital costs. All three scenarios reflect the same assumptions regarding jurisdictional emissions targets (consistent with the ISP) and the South Australia inertia requirement.

One submission commented that the high scenario assumptions in the PADR of a tightening of the inertia constraint in South Australia to a 1 Hz/s RoCoF combined with high gas prices was unrealistic.[155] We consider that such a tightening is a potential future outcome. However, the PACR modelling now applied the current South Australian Government inertia requirement (ie, the 3 Hz/s limit) to all scenarios investigated. Any such tightening of this requirement would only increase the estimated net market benefits of the preferred option.

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.

154 The AER RIT-T Application Guidelines explicitly refer to the role of scenarios as the primary means of taking uncertainty into account: 'Where the calculation of the market benefits or costs of a credible option is affected by material uncertainty over the future market supply and demand conditions and characteristics, this is to be primarily reflected in the choice of the range of reasonable scenarios'. See: AER, RIT-T Application Guidelines, 18 September 2017, p. 30 (which was also reiterated in the recently updated Guidelines, see: AER, RIT-T Application Guidelines, December 2018, p. 42).

155 See discussion in section 4.1.3.

Table 8 – Summary of key variables in each of the scenarios considered

Variable	Central Scenario	Low Scenario	High Scenario
Electricity demand (including impact from distributed energy resources)	AEMO 2018 ESOO neutral demand forecasts	AEMO 2018 ESOO slow change demand forecasts	AEMO 2018 ESOO fast change demand forecasts plus potential SA spot load development of 345 MW
Gas prices – long-term	$9.17/GJ (AEMO ISP Neutral scenario)	$7.40/GJ ($0.62/GJ lower than AEMO ISP Slow change)	$11.87 GJ in Adelaide ($1.68/GJ higher than AEMO ISP Fast change scenario)
Emission reduction renewables policy – in addition to Renewable Energy Target (RET)	Emissions reduction around 28% from 2005 by 2030 (AEMO ISP Neutral scenario; Federal government policy)	No explicit emission reduction target beyond current RET	Emissions reduction around 52% from 2005 by 2030 (AEMO ISP Fast change scenario)
Jurisdictional emissions targets	VRET 25% by 2020 and 40% by 2025 QRET 50% by 2030		
SA inertia requirement – RoCoF limit for non-credible loss of Heywood Interconnector	3 Hz/s (current SA Government requirement)		
Generator capital costs	AEMO 2018 ISP	15% lower than central scenario	15% higher than central scenario

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

In developing these scenarios, we have drawn on the 2018 ISP inputs developed by AEMO, and in particular on the slow change, neutral and fast change ISP scenarios, as well as on AEMO's July 2018 ESOO.[156] However, to provide a broad enough range of assumptions to adequately test the robustness of the RIT-T outcome, some divergence from the ISP scenarios has been applied.

156 AEMO Electricity Statement of Opportunities 31 July 2018.

In relation to future demand, we have continued to include in the 'high' scenario additional demand associated with potential future loads in South Australia, in particular reflecting all potential new mining project developments in South Australia.

Moreover, as section 8 sets out, the identification of the preferred option is the same in all three scenarios investigated and so amending this assumption would not affect the conclusion of this PACR (instead, the net market benefits of all options would likely fall slightly under the high scenario if the MW of potential new load was reduced).

We have also continued to adopt high and low forecasts for gas prices in our assessment, which are wider than 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),[157] 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.[158]

Finally, our low scenario includes no explicit emissions reduction target beyond the current RET, in contrast to the ISP slow change assumption of a 28 per cent reduction by 2030. We have also now aligned with the ISP in testing the impact of a 52 per cent reduction in emissions by 2030 (reflecting the ISP 'fast change' scenario).

7.2 Weighting of the reasonable scenarios

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

Table 9 – Assumed weights applied to each reasonable scenario

Central scenario	Low scenario	High scenario
50%	25%	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 8), we have also carefully considered the results in each scenario.

157 Refer to earlier EnergyQuest report.

158 The results of this RIT-T were tested to the extreme $5.89/GJ assumption in the PADR, and it was found to not affect the identified preferred option.

We have also tested the robustness of the selection of the preferred option to the underlying scenario weightings (see section 8.4). We found that the conclusions of this RIT-T are independent of 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, we have also continued to consider the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing.

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

- higher than anticipated NSW coal prices – this can be expected to impact the owners' decisions about whether to undertake refurbishment of those plant to extend their lives, or to retire them, and so has an impact on the modelled retirement dates for NSW coal plant;
- the potential for a SA-Queensland interconnector option (Option B) to defer the second stage of a QNI upgrade – we have assumed for the purpose of this sensitivity that this second stage ($560 million) is deferred for 10 years;
- the outcome of the coincident Victorian RIT-T being undertaken by AEMO. However, in contrast to the PADR this sensitivity now reflects an increase in costs for the SA-Victoria interconnector option (Option D) if the Western Victoria augmentation does not go ahead, given the change in the base case assumption that this Group 1 ISP project will proceed;
- removing the minimum operation constraints on these plants (ie, consistent with the approach taken the PADR);
- assuming that all units of Torrens Island B retire at or before 50-years of age under the base case;
- assuming a new interconnector has no impact on the operation of Pelican Point and Osborne (ie, they do no retire nor change their behaviour);
- lower assumed avoided REZ transmission cost benefits;
- lower assumed non-network costs;
- lower HVDC costs compared to HVAC costs;
- a shorter assessment period;
- removing terminal values from the assessment; and
- other general sensitivities, ie, discount rates, capital cost estimates.

The results of the sensitivity tests are discussion in section 8.5.

8. Net present value results

Summary points:

- Option C.3 (a new 330 kV interconnector between South Australia and New South Wales, via Buronga, with an augmentation between Buronga and Red Cliffs) has the greatest net market benefit of all options in each of the three scenarios considered.
- The net benefit of Option C.3 is predominantly driven by dispatch cost benefits (in particular avoided South Australian gas generation) and ranges from $720 million (low scenario) to $1.34 billion (high scenario) over the 21 year assessment period.
- This conclusion is robust to a range of sensitivity tests and more extreme ‘robustness tests’.

This section outlines the results of the economic assessment. In particular, it presents the results for each of the three scenarios outlined in section 7.1 above, discusses the weighted results and then presents all sensitivity tests investigated.

8.1 Central scenario

The central scenario reflects the best estimate of the evolution of the market going forward, including ‘neutral’ demand forecasts, a long-term gas price of $9.17/GJ, generator capital cost assumptions based on the ISP and a national emissions reduction of around 28 per cent below 2005 levels by 2030.[159]

The PACR assessment finds that a new 330 kV line between Robertstown in the mid-north region of South Australia and Wagga Wagga in New South Wales, via Buronga, with an augmentation between Buronga and Red Cliffs (ie, Option C.3) provides the greatest net market benefit under the central set of assumptions.

Option C.3 is estimated to have the greatest net market benefit of all options considered at approximately $765 million, which is around $100 million (15 per cent) greater than Option C.3.ii (the next best South Australia - NSW option, routed via Kerang in Victoria) and $485 million greater than Option D (the top ranked non-NSW option). The South Australia – Queensland option (Option B) is found to only have a relatively marginal net market benefit ($50 million).

Option A (the non-interconnector option) is estimated to have a net market cost of approximately $75 million.

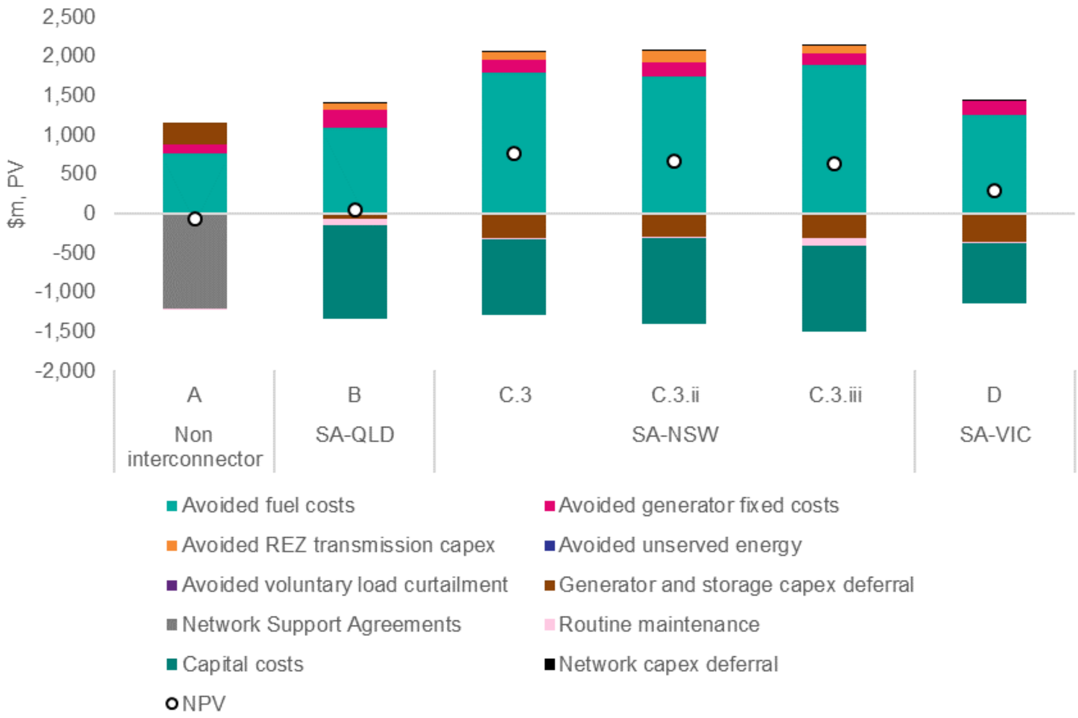
The figure below shows the overall estimated net market benefit for each option under the central scenario.

159 A full summary of all key assumptions in this scenario can be found in Table 8 in section 7.

Figure 10 – Summary of the estimated net market benefits under the central scenario

Figure 11 shows the composition of estimated net market benefits for each option under the central scenario.

Figure 11 – Breakdown of estimated net market benefits under the central scenario



The key findings from the updated assessment of all options are that:

- Market benefits of all options continue to be primarily derived from avoided variable costs associated with the dispatch of generation (principally avoided South Australian gas generation).

  - This benefit accrues immediately and has risen from the PADR as a result of changed assumptions regarding the operation of South Australian gas generators (refer to section 4.1) as well as higher demand in line with the 2018 ESOO forecasts.

  - New interconnector options allow more variable generation from South Australia, particularly wind, to be exported to the rest of the NEM over time and reduce 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 the gas generators in South Australia, which results in avoided fixed operation and maintenance costs compared to the base case.

  - This benefit has fallen since the PADR as Torrens Island B, which has a relatively large fixed operating cost, is now retired in the base case (the PADR found that it did not retire under the base case) while Osborne and Pelican Point are now expected to retire after interconnection, but only partly offsetting this benefit decrease due to their relative fixed costs – as a result the present value of these avoided costs is now estimated to be $155 million for the preferred option, whereas it was estimated at $208 million in the PADR.

- 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, and storage in South Australia, which provides dispatchable capacity, that replaces gas fired generation.

- The NSW and Queensland interconnector options provide benefit through being able to avoid the intra-regional transmission costs that would otherwise be required to unlock additional renewable generation resources (ie, the 'avoided REZ transmission capex' benefit).[160]

  - The avoided REZ transmission capex benefit is lower than estimated in the PADR.[161]

  - These estimated benefits for Option B are in the order of $75 million, which is actually less than the cost of the mid-point converter station required to generate them ($280 million) – removing both this cost and benefit from the assessment of Option B increases its estimated net market benefits (from $50 million to $350 million) but it is still found to be materially below Option C.3.

[160] The ability of the Queensland option to deliver these benefits has been included since the PADR in response to submissions, as outlined in sections 4.2.2 and 5.3.3. This has required the inclusion of a mid-point converter station as part of this option.

[161] As outlined in section 6.3, the REZ developments identified by AEMO in the ISP have now been reflected in the network representation used for the market modelling, which enables the associated transmission deferral benefits to be estimated as an outworking of our market model. The accompanying market modelling report presents more detail on the approach we have adopted.

   - Similar benefits do not arise under the Victorian option, as the Western Victoria augmentation assumed in the base case will unlock the REZ in that area, and there will be no further benefits in connecting back to Adelaide.

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

   - Correspondingly, Option B has the highest estimated costs due to the relatively long line length required to connect South Australia to Queensland.

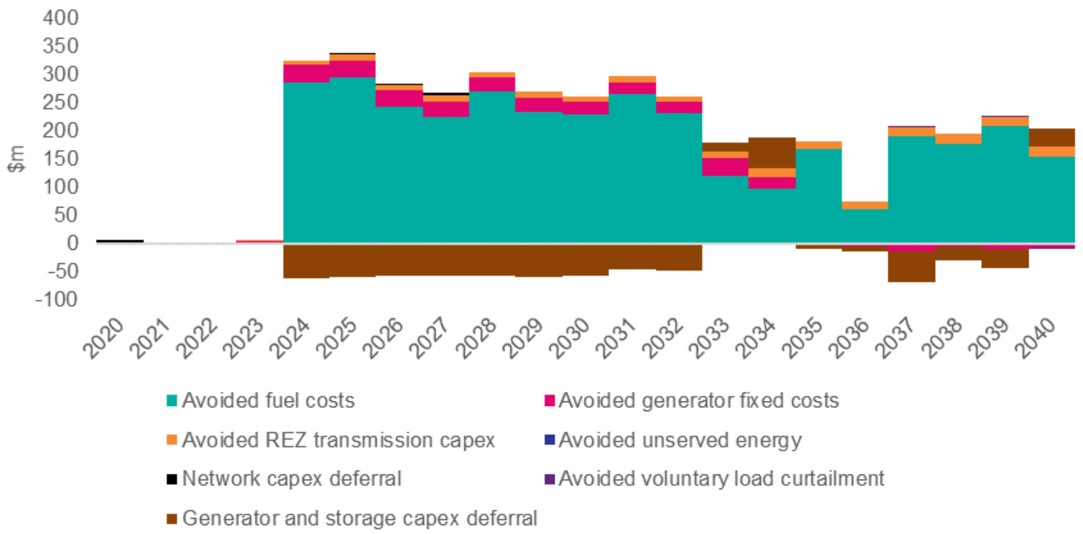
   - Option D, the interconnector option to Victoria, has the lowest costs out of the interconnector options, due to the relatively short line distance and the assumption that part of the augmentation will be completed as part of the separate Western Victoria augmentation being progressed by AEMO.

- 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.

   - These costs have been largely sourced directly from proponents and were not commented on by these parties in submissions to the PADR. On the whole, the non-interconnector option cost in NPV terms over the assessment period is of similar magnitude to the interconnector options, as shown in Figure 11 above.

The figure below presents the estimated gross benefits for Option C.3 for each year of the assessment period under the central scenario.[162]

Figure 12 – Breakdown of gross market benefits for Option C.3 (SA-NSW interconnector) under the central scenario



[162] This figure only presents the annual breakdown of estimated gross market benefits for the preferred option. The separately released spreadsheet presents an annual breakdown of costs and benefits for all options.

The benefits of avoided fuel costs appear as soon as the interconnector is energised, as do the avoided fixed generator operation and maintenance costs, primarily as South Australia gas generators retire. The avoided fuel costs last the length of the period but reduce over time, reflecting the fact that affected generators would eventually retire under the base case, at which point the predominant flow on the interconnector reverses and provides energy to New South Wales.

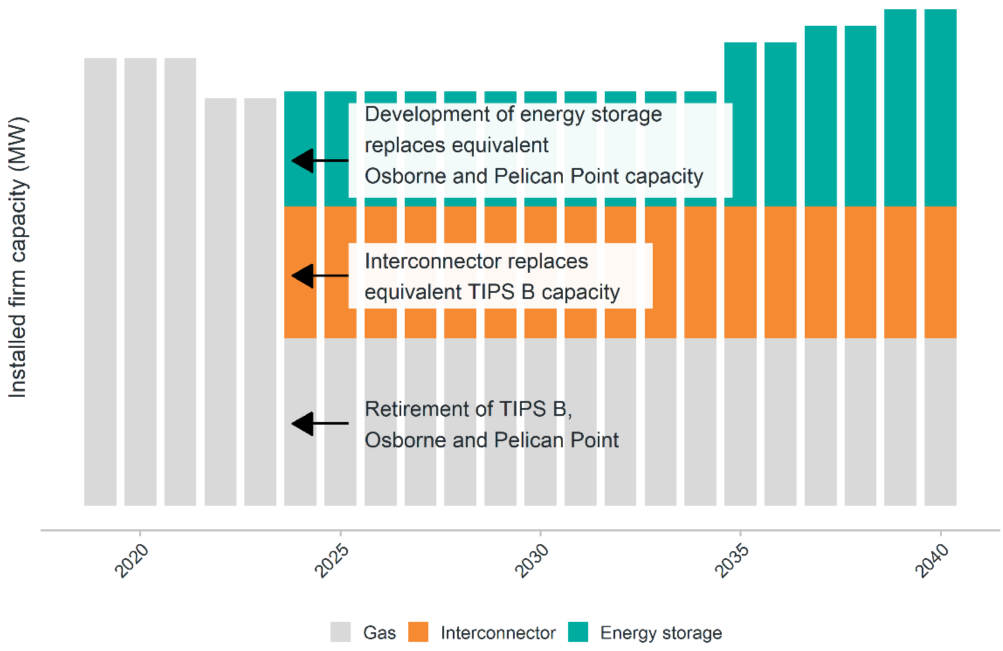
In terms of the underlying key changes in generator output (in GWh), relative to the base case, Option C.3 is found to avoid a significant amount of South Australian gas generation, which is offset by New South Wales black coal generation (primarily in the short- to medium-term, ie, before Eraring and Bayswater retire in 2034 and 2035) as well as significant additional output from renewable sources (both existing and new REZ sources).

While there is an increase in low cost New South Wales black coal generation with Option C.3 in-place, which has a high emissions intensity, there is a much larger corresponding reduction in South Australian gas generation, which also has a high emissions intensity. Moreover, the national emissions reduction of around 28 per cent below 2005 levels by 2030 is met with the interconnector in place (as it is under the base case).

From the mid-2030s (ie, after Eraring and Bayswater retire), variations in avoided dispatch reflect a greater utilisation of existing plant, which avoids the need for investing in new plant to meet New South Wales demand. There is also found to be a significant benefit from avoided or deferred investment in new generation and storage that would otherwise be required when Eraring and Bayswater retire (shown by the brown benefit in 2033 and 2034 in Figure 12 above).

The modelling shows the South Australian gas generation capacity that retires with a new interconnector in-place is replaced by both new transfer capacity and energy storage. The figure below shows that new transfer capacity effectively replaces the capacity lost from Torrens Island B retiring, while new energy storage replaces the equivalent capacity lost from Osborne and Pelican Point retiring.

Figure 13 – Installed major gas capacity in South Australia under Option C.3



The avoided REZ transmission capital costs also appear as a benefit from as soon as the interconnector is energised, which reflects that Option C.3 lowers the cost of connecting renewable generation in western Victoria.

These benefits were not included in the PADR as they relate to the Buronga to Red Cliffs augmentation that has been added to the preferred option since the PADR was released. The benefit of these lower REZ transmission capital costs almost doubles from the mid-2030s, consistent with when these costs would be incurred otherwise to replace retiring coal in New South Wales.

There are large negative benefits (ie, costs) associated with generator and storage capital expenditure across the period due to increasing investment in higher capital cost, yet overall more efficient plant. This is driven by the finding that new energy storage in South Australia replaces Pelican Point and Osborne power stations with a new interconnector in-place.

8.2 Low scenario

The low scenario is intended to represent the lower end of the potential range of realistic net benefits associated with the various options.

The low scenario is therefore based on a set of conservative assumptions reflecting a future world with low demand forecasts, a lower long-term gas price ($7.40/GJ), generator capital costs that are 15 per cent lower than the ISP assumptions and no explicit national emission reduction target beyond the current RET. [163]

Under the low scenario, the South Australia – New South Wales interconnector options continue to rank materially ahead of interconnection with either Victoria or Queensland. Net market benefits for Option C.3 are $720 million, or $45 million (6 per cent) below the estimated net market benefit in the central scenario.

Option C.3 remains the top-ranked option with marginally greater net benefits ($55 million/ 8 per cent) than Option C.3.ii (the second ranked option overall) and $520 million over Option D (the top ranked non-NSW option).

The net benefits of the South Australia – Queensland option increases in this scenario (to $200 million). Option B performs better under the low scenario with a more efficient delivery of generator and storage capital deferrals and resulting fuel costs savings matching the preferred option more closely.

Option A continues to have a significant estimated net market cost.

The figure below shows the overall estimated net market benefit for each option under the low scenario.

Figure 14 – Summary of the estimated net market benefits under the low scenario

163 A full summary of all key assumptions in this scenario can be found in Table 8.

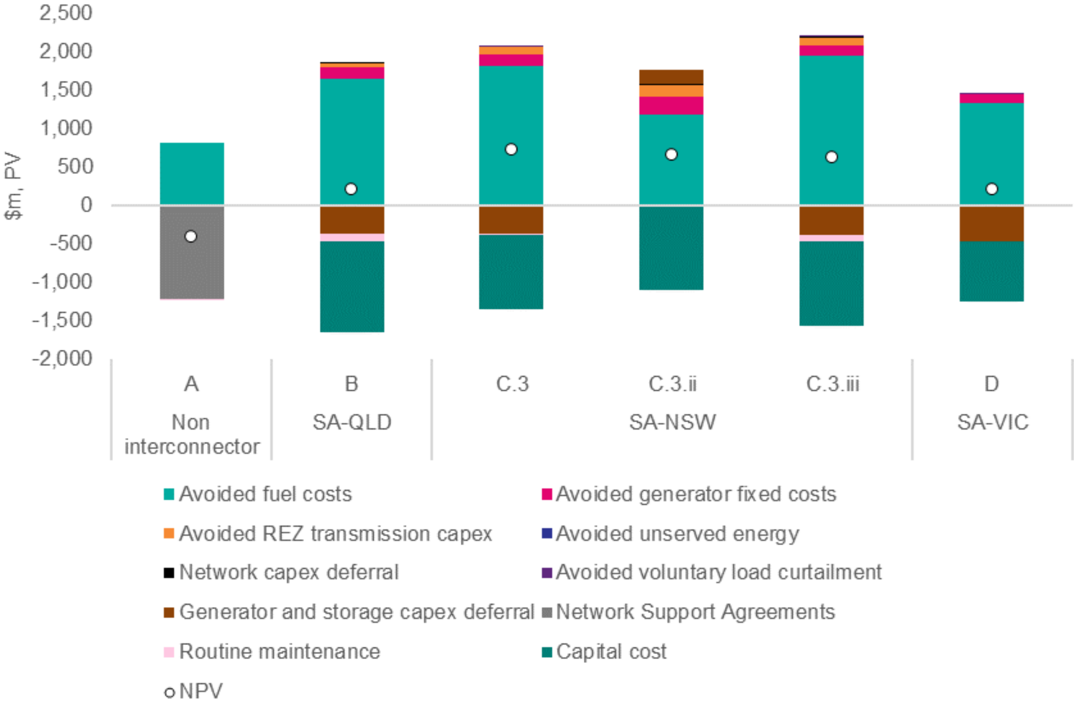
ElectraNet
electranet.com.au

The figure below shows the composition of estimated net market benefits for each option under low scenario.

As with the central scenario, the majority of the estimated market benefits are attributed to the avoidance of dispatch of gas fired generation in South Australia. However, due to the low gas price assumption and lower demand assumptions in this scenario, the level of avoided dispatch costs is lower relative to the other scenarios considered.

A key difference 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 greater net saving. This is because the only driver of investment under the low scenario is to replace coal generators (ie, there is no load growth included, and no national emission reduction target) and interconnection allows existing generators to be used more efficiently.

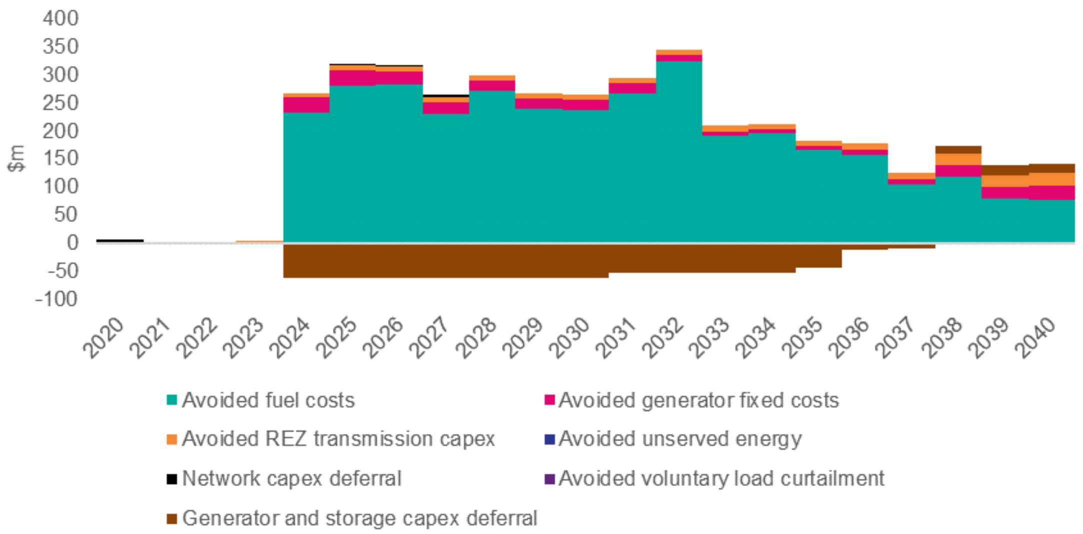
Figure 15 – Breakdown of estimated net market benefits under the low scenario



The figure below presents the estimated gross benefits for Option C.3 for each year of the assessment period under the low scenario.[164] The pattern of estimated benefits is similar to the central scenario (the key exception relates to the profile of generator deferral, as noted above).

[164] This figure only presents the annual breakdown of estimated gross market benefits for the preferred option. The separately released spreadsheet presents an annual breakdown of costs and benefits for all options.

Figure 16 – Breakdown of gross market benefits for Option C.3 under the low scenario



8.3 High scenario

The high scenario represents the upper end of the potential range of realistic net benefits associated with the various options.

The high scenario is therefore based on a strong set of assumptions regarding the net market benefits, and reflects a world with higher demand forecasts (including potential additional South Australian spot load development), a higher long-term gas price ($11.87/GJ), generator capital costs that are 15 per cent higher than the ISP assumptions and a more aggressive national emissions reduction.[165]

The South Australia – New South Wales options continue to perform materially better than the alternative interconnector options under this more aggressive scenario. The overall net benefit is substantially higher than in the central scenario.

Option C.3 remains the top-ranked option with estimated net market benefits of approximately $1.34 billion. This is around $100 million/8 per cent higher than option C.3.iii (the second ranked option overall).

Under the high scenario, Option B is found to be the highest ranked non-NSW option, but is still materially below Option C.3 ($280 million lower, or 21 per cent).

Option A has a positive net benefit in the high scenario but is still materially lower than the interconnector options.

The figure below shows the overall estimated net market benefit for each option under the high scenario.

[165] A full summary of all key assumptions in this scenario can be found in Table 8.

Figure 17 – Summary of the estimated net market benefits under the high scenario

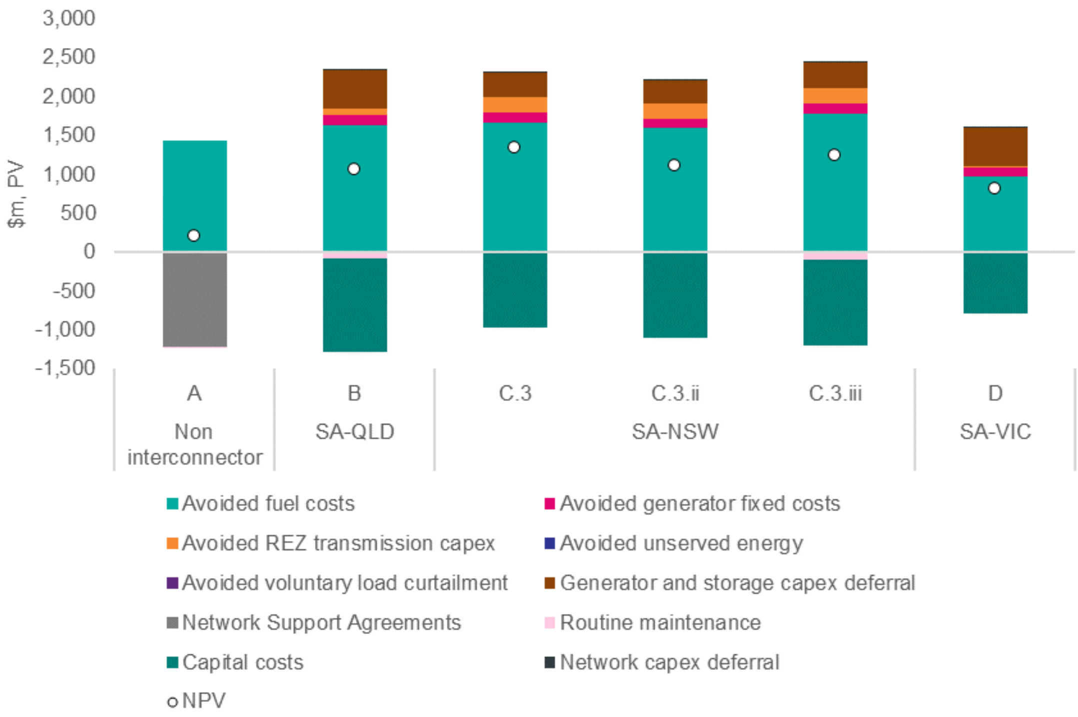
Under the high scenario, the gross market benefits are substantially higher relative to the central scenario.

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 higher demand forecasts and stronger emission limitations which drive increased gas fired generation across the NEM in this scenario in the absence of interconnection.

The figure below shows the composition of estimated net market benefits for each option under the high scenario.

Figure 18 – Breakdown of estimated net market benefits under the high scenario

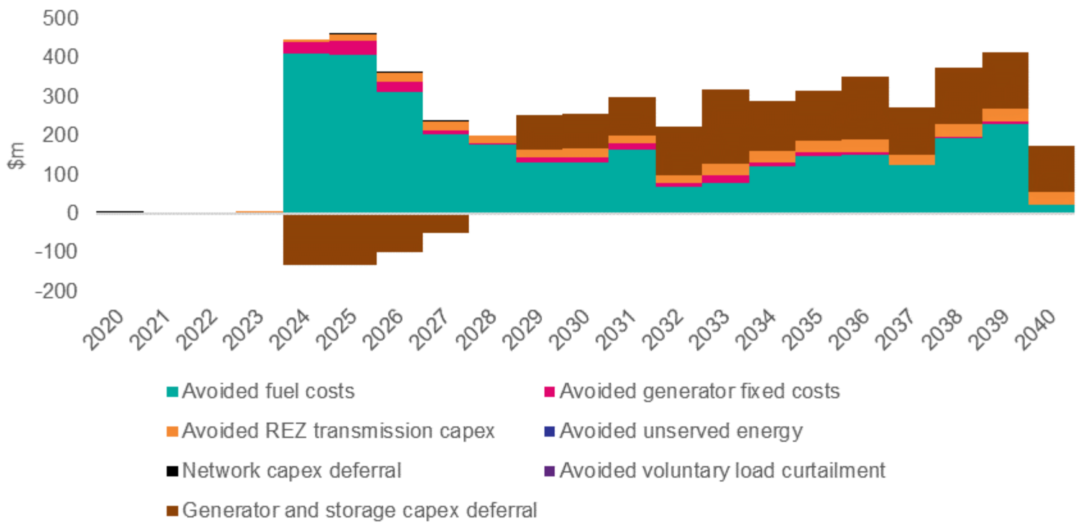


The figure below presents the estimated gross benefits for Option C.3 for each year of the assessment period under the high scenario.166

While there is a greater overall quantum of avoided fuel costs estimated than under the other scenarios, this benefit tapers off more quickly under the high scenario. This is due to the finding that investment in new generators and storage ramps up under the high scenario (due higher demand and the higher emissions target included in this scenario), as shown in brown below, which offsets the fuel cost savings initially realised.

[166] This figure only presents the annual breakdown of estimated gross market benefits for the preferred option. The separately released spreadsheet presents an annual breakdown of costs and benefits for all options.

Figure 19 – Breakdown of gross market benefits for Option C.3 under the high scenario



8.4 Weighted net market benefits

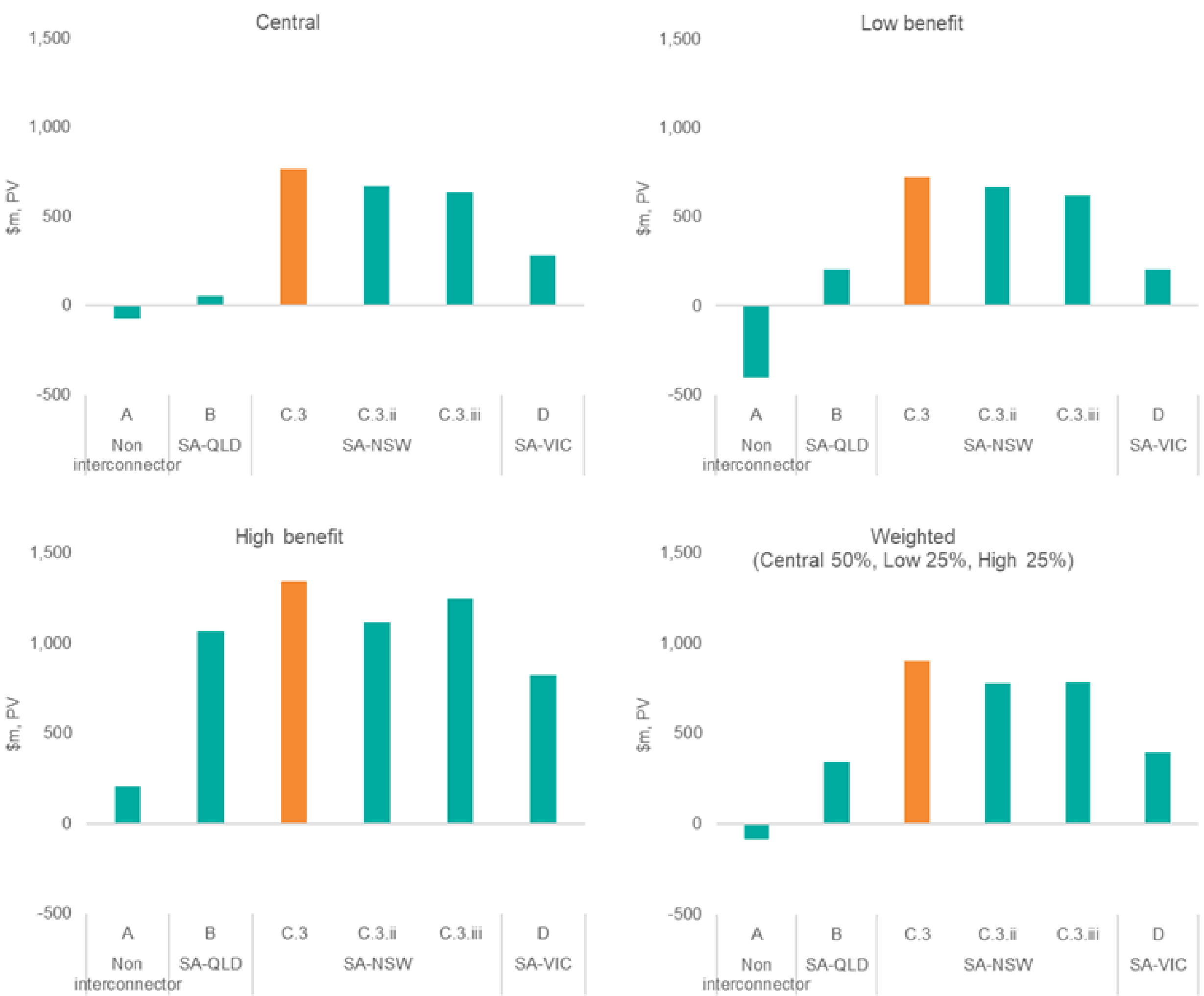
The figure below shows the net market benefits under all three scenarios and the weighted outcome.

The preferred option across all scenarios is Option C.3. The finding that Option C.3 is the preferred option is therefore independent of the weightings applied to the scenarios.

This is consistent with the finding in the PADR and means that investment in Option C.3 is a 'no regrets' decision.

Under the weighted outcome, Option C.3 is expected to deliver approximately $900 million of net market benefits.

Figure 20 - Net market benefits under all scenarios



8.5 Sensitivity analysis

We have undertaken a range of sensitivity analyses to test the robustness of the market modelling outcomes. Specifically, we have assessed:

- the potential for a South Australia to Queensland interconnector option (Option B) to defer the second stage of a QNI upgrade;
- the impact of the Western Victoria Renewable Integration augmentation not going ahead;
- removing the minimum operation constraints on South Australian gas plants (ie, consistent with the approach taken the PADR, as discussed in section 4.1.1);
- the estimated capital costs of the interconnector options; and
- the commercial discount rate applied.

To simplify the presentation of the results in this section, we have only presented one South Australia to New South Wales option in each sensitivity chart, ie, so there is only one option for each route depicted. Where the NSW option is not the preferred Option C.3 we discuss this and compare the top ranked NSW option to Option C.3.

All assumptions in each sensitivity match those used in the central scenario, with the exception of the variable being tested.

In addition, section 0 outlines further testing undertaken of the robustness of the preferred option. This additional testing has largely been undertaken in response to points raised in submissions to the PADR and reflects:

- removing the 'avoided REZ transmission cost' benefit;
- lower non-network costs;
- lower HVDC costs for the South Australia to Queensland HVDC option compared to the other options;
- higher coal prices for NSW generators; and
- a shorter assessment period.

While the three scenarios investigated include a wide range of underlying gas prices (and a wider range than contemplated in the ISP), we have not undertaken a standalone gas price sensitivity as part of the PACR. The PADR assessment tested gas prices down to $6/GJ (ie, below those assumed in the low scenario).

At this price, the preferred option did not change and the preferred option continued to deliver net market benefits. We also note that $6/GJ gas prices appear to be well below all realistic expectations of future gas prices delivered to Adelaide based on independent advice, ISP assumptions and stakeholder feedback.

8.5.1 The potential for Option B to defer Stage 2 of the QNI upgrade

The PADR assumed that Option B would defer all of the QNI upgrade. We have amended our assumption on the scope for potential transmission investment deferral under a new South Australia - Queensland interconnector to be a deferral of Stage 2 of the QNI upgrade only. This reflects identification by AEMO in the ISP of Stage 1 of the QNI upgrade as a Group 1 project, ie, a project that should be pursued immediately.

To test the sensitivity of the preferred option to this assumption we have assumed that the $560 million[167] Stage 2 upgrade is deferred by ten years under Option B.

The figure below shows that this assumption *removes* approximately $330 million from the estimated net market benefits of Option B. Under these assumptions, Option B is found to have significant overall estimated net market cost and continues to be ranked substantially below Option C.3.

[167] TransGrid & Powerlink, *Expanding NSW-QLD transmission transfer capacity*, Project Specification Consultation Report, November 2018, p. 26.

Figure 21 – Impact of assuming Option B defers QNI Stage 2 by 10 years

This result is driven by the finding that, while there is a benefit of approximately $270 million due to the deferral of the Stage 2 QNI investment by ten years, the estimated fuel cost savings for Option B have declined by around $560 million (on account of the Stage 2 investment being deferred).

On balance, there is no net benefit to Option B from delaying the QNI Stage 2 augmentation.

8.5.2 Interaction with the Western Victoria Renewable Integration RIT-T

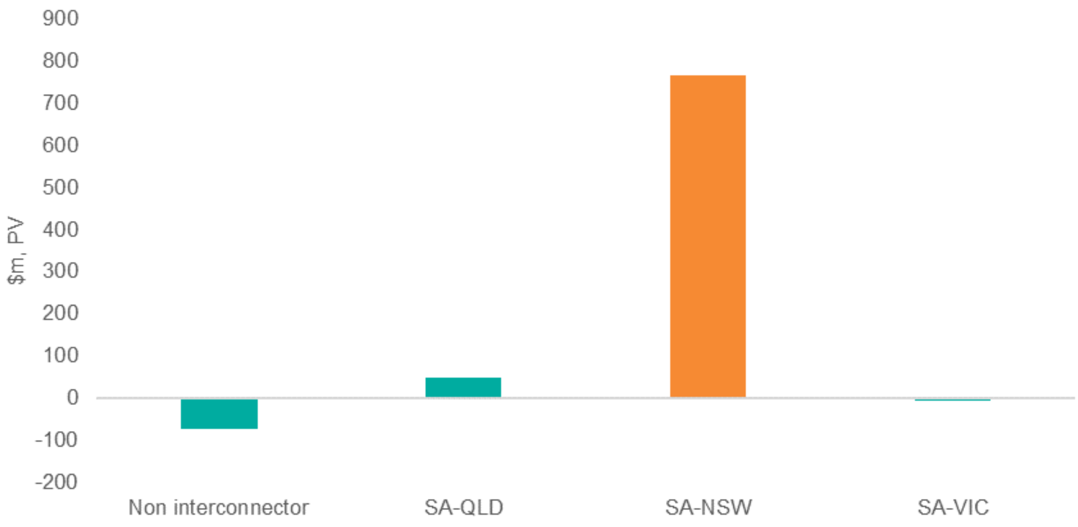
We have considered the interaction between this RIT-T and AEMO's concurrent Western Victoria RIT-T. However, in contrast to the PADR, this sensitivity now reflects an *increase* in costs for the South Australia - Victoria interconnector option (Option D) if the Western Victoria augmentation does not go ahead, given the change in the base case assumption that this Group 1 ISP project will proceed.

In addition, in the event that this separate investment does not proceed, there would be a decrease in the market benefit of South Australia – New South Wales interconnection via Buronga.

The figure below demonstrates that the identification of Option C.3 as the preferred option is not affected by the outcome of the Western Victoria RIT-T.

Option D is now found to have negligible estimated net market benefits and the difference in estimated net market benefits between Option C.3 and Option D has widened from those shown in Figure 10 from $485 million to $770 million.

Figure 22 – Impact of assuming the Western Victoria Renewable Integration does not proceed



8.5.3 Alternate assumptions regarding minimum operation levels of SA gas generators

Several submissions raised questions relating to the assumed timing of the retirement of gas-fired generators in South Australia in the PADR modelling, and the differences with the ISP. Section 4.1.1 outlines the reasons for the observed differences between these two sets of modelling results, including because the PADR did not assume any minimum operation levels for South Australian gas plant.

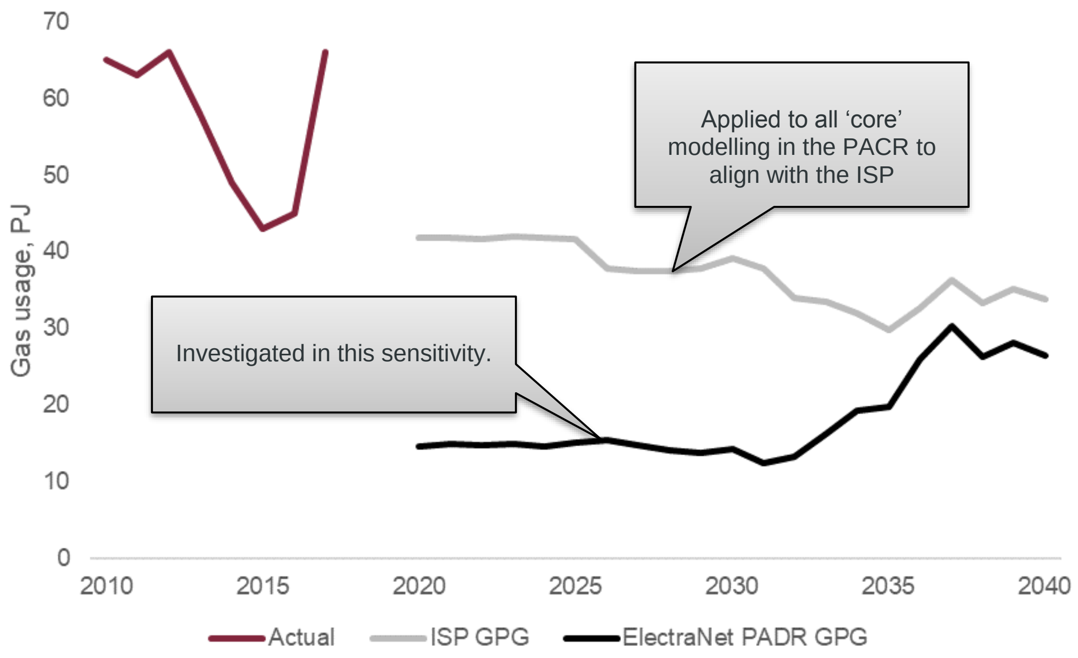
While the PACR assumes minimum operation levels for South Australian gas plant (similar to ISP), we have also investigated a sensitivity where these do not apply (ie, consistent with that assumed in the PADR).

The figure below demonstrates the extent of difference in the modelled operation of these generators under the base case, in terms of the gas used in aggregate, as well as how each sits relative to historical gas usage by South Australian gas generators.

Specifically, it shows that the PACR minimum operation levels are lower than actual historical gas usage by generators in South Australia, while the PADR operation levels, which have been applied in this standalone sensitivity, are well below both these levels.

We therefore consider that this sensitivity represents a highly conservative set of assumptions.

Figure 23 – Summary of the two different South Australian gas generator assumptions investigated – aggregate gas usage for SA gas powered generation (GPG) under the base case



The figure below demonstrates that even under these conservative assumptions, Option C.3 continues to be the preferred option and continues to have positive net market benefits.

Figure 24 – Impact of alternate assumptions regarding the operation of SA gas plants

The estimated net market benefits of all options are below those shown in Figure 10 on account of the reduced scope for avoiding fuel costs under the base case in which Torrens Island B is assumed to retire (as discussed in section 4.1.1).

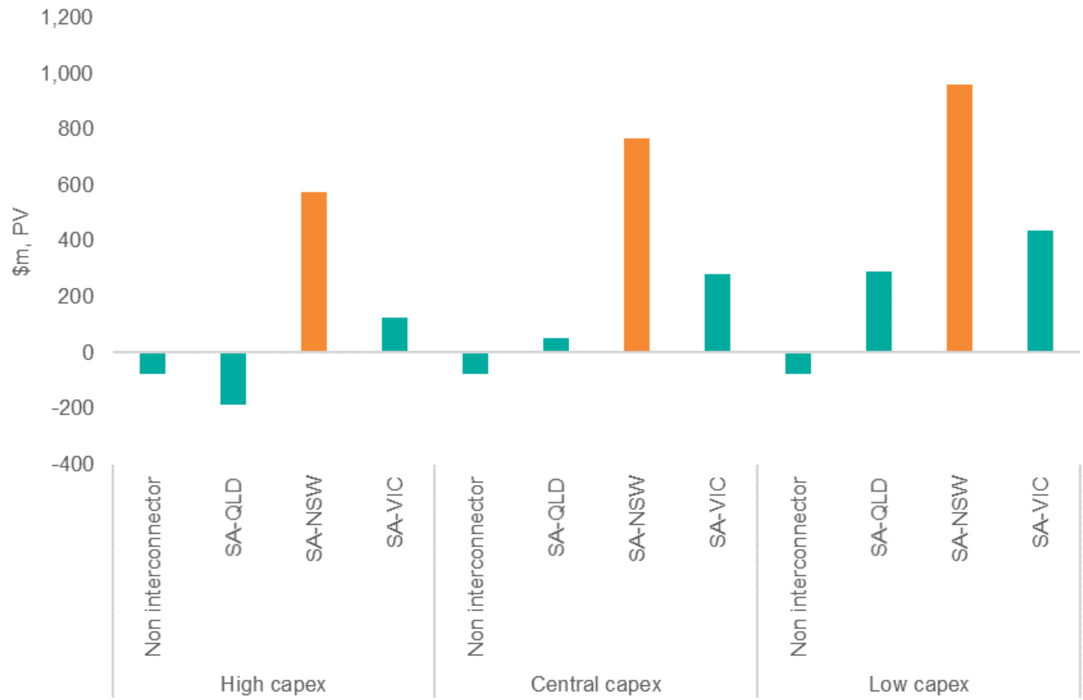
8.5.4 Estimated interconnector option capital costs

As in the PADR, we have tested the sensitivity of the results to the underlying capital costs of the interconnector options.

The figure below shows that Option C.3 remains the preferred option under 20 per cent lower and higher capital cost assumptions. For clarity, this changes the capital costs of all options at the same time.

Option A's estimated net market benefits are not affected in this sensitivity since its costs are in the form of network support agreements (ie, operating expenditure). A sensitivity is run on the estimated costs of Option A in section 0.

Figure 25 – Impact of 20 per cent higher/lower capital costs



We have extended this sensitivity testing and find that Option C.3's capital costs would need to be at least 80 per cent higher than the central estimates for it to no longer have positive estimated net market benefits.

Furthermore, capital costs of all options would need to be at least 260 per cent higher than the central capital cost estimates for Option D to become preferred over Option C.3.

8.5.5 Discount rates

The figure below illustrates the sensitivity of the results to different discount rate assumptions. In particular, it illustrates three tranches of net market benefits estimated for each credible option – namely:

- a high discount rate of 8.5 per cent;
- the central discount rate assumption of 6 per cent; and
- a low discount rate of 3.8 per cent.

Option C.3 is preferred under all three different discount rate assumptions. We have extended this sensitivity and find that the discount rate would need to be almost 14 per cent (real, pre-tax) for Option C.3 to have a negative estimated net market benefit.

Figure 26 – Impact of different discount rates

ElectraNet
electranet.com.au

8.6 Additional robustness testing

In addition to the sensitivity tests run in the sections above, we have also investigated a number of further robustness tests in response to points raised in submissions. These include:

- removing the 'avoided REZ transmission cost' benefit;
- lower non-network costs;
- lower HVDC costs for the South Australia to Queensland HVDC option compared to other options;
- higher coal prices for NSW generators;
- a shorter assessment period;
- removing terminal values from the assessment;
- assuming that all units of Torrens Island B retire at or before 50-years of age under the base case; and
- assuming a new interconnector has no impact on the operation of Pelican Point and Osborne (ie, they do no retire nor change their behaviour).

All variables remain the same as in the central scenario, with the exception of the variable being tested.

The results of each of these additional robustness tests is outlined in the sections below.

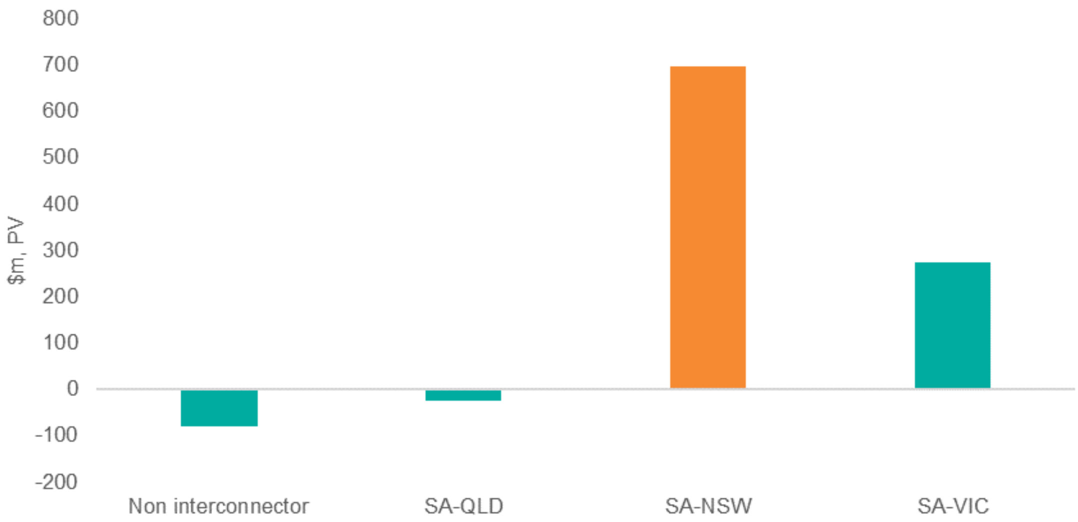
8.6.1 Avoided REZ transmission cost benefit

A range of submitters queried whether the RIT-T framework could include benefits associated with the avoided transmission costs for future REZ development. Section 4.2.2 outlines how this category of market benefits is consistent with the RIT-T framework.

Notwithstanding, we have investigated an extreme sensitivity that removes all of these benefits from the assessment. This sensitivity removes all estimated avoided REZ transmission capital cost benefits as well as the additional converter station from the Queensland option (as this allows these benefits to be captured in the core set of results) and the cost of the Buronga to Red Cliffs augmentation from the New South Wales options.

The results of this sensitivity are shown in the figure below and show that Option C.3 continues to have the highest net market benefit of all options, even when the avoided REZ transmission cost benefit is excluded.

Figure 27 – Impact of removing the avoided REZ transmission cost benefit



While ElectraNet has tested this sensitivity, recent market developments have proceeded at a faster rate than anticipated. Since late 2018, over 600 MW of solar generation has reached committed status west of Wagga Wagga. This level of generation has exceeded the trigger for TransGrid's 'Support South Western NSW for Renewables' contingent project. Additional triggers for this project in north western Victoria have also been exceeded.

Irrespective of the outcome of this RIT-T, south western NSW will require augmentation in the next five years. TransGrid's contingent project application estimated the likely costs of augmentation at between $89 and $473 million. These costs are likely to be incurred in all options considered in this RIT T and are already included in the costs of Option C.3 and variants.

While ElectraNet has modelled the benefit of avoided REZ transmission costs, these recent market developments have proceeded at a faster rate than anticipated and have not been captured in this assessment. Their inclusion is expected to add to the estimated net market benefits of the preferred option.

In addition, the NSW government transmission strategy is seeking to connect 4,950 MW of capacity centred on Hay along the existing Balranald to Buronga corridor to facilitate the retirement of NSW black coal generators.[168]

[168] NSW Transmission Infrastructure Strategy, available at: https://energy.nsw.gov.au/renewables/clean-energy-initiatives/transmission-infrastructure-strategy

8.6.2 Reduction in the estimated non-interconnector costs

The Energy Project submitted that the costs of the non-interconnector option (Option A) had been overestimated in the PADR. As set out in Appendix F, the costs of Option A are based on offers submitted by potential proponents.

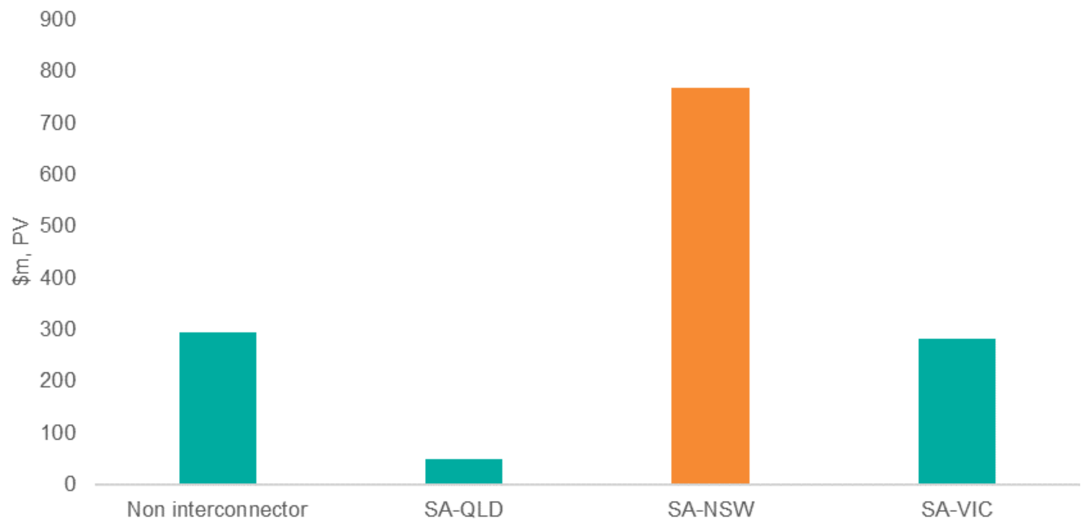
Notwithstanding, we have tested the sensitivity of the identification of the preferred option to a 30 per cent reduction in the assumed annual network support payments made under Option A, whilst keeping the costs of the interconnector options constant.

This reflects both the points raised by The Energy Project but also the potential for funding outside of the NEM to reduce the costs of this option, eg, through schemes such as the $50 million fund the South Australian Government announced in November 2018 to support new energy storage projects.[169]

The figure below summarises the results of this sensitivity and demonstrates that Option C.3 remains the preferred option, even if the costs of the components of Option A were assumed to be 30 per cent lower.

Moreover, from threshold analysis, we find that Option A's costs would need to reduce by approximately 70 per cent from the central cost estimates for it to be ranked equal first with Option C.3.

Figure 28 – Impact of assuming 30 per cent lower Option A costs



[169] Premier of South Australia's website, available at: https://premier.sa.gov.au/news/50-million-fund-to-support-new-energy-storage-projects-to-make-electricity-more-affordable-and

8.6.3 Reduction in the Queensland HVDC costs

ARCMesh noted in its submission that it has undertaken assessments of the optimal scope and design of an HVDC interconnection from South Australia to Queensland and considers that its costs could be 24 per cent lower than those estimated in the PADR.[170]

While Appendix G provides detailed responses to each of the points raised by ARCMesh, we have also undertaken a further sensitivity by reducing the costs of the South Australia to Queensland HVDC Option B by 25 per cent, whilst leaving the costs of the other options unchanged.

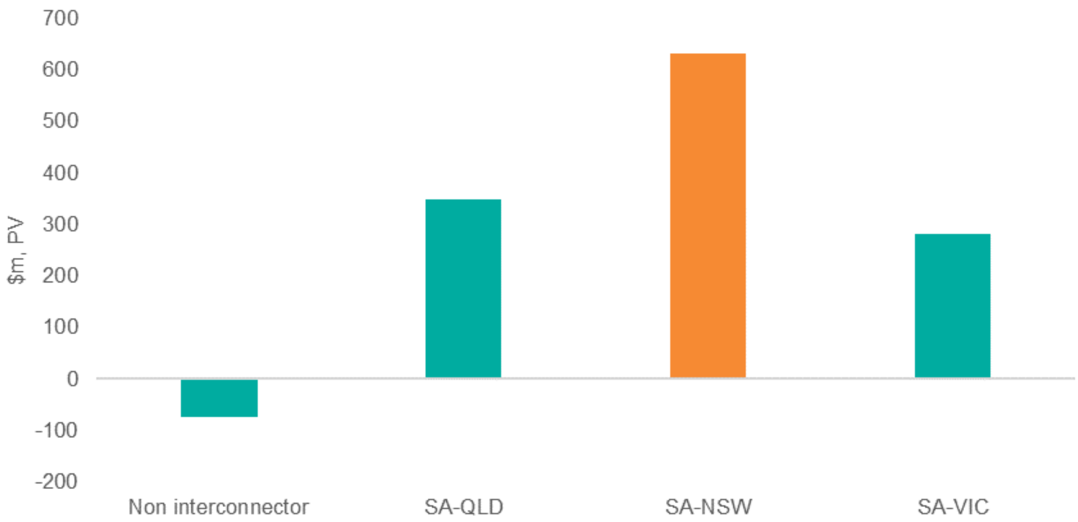
This 25 per cent reduction in the total cost of the option is equivalent to reducing the HVDC line cost by 50 per cent (ie, by assuming no reduction in convertor station costs).

This cost reduction is on top of the reduction in HVDC line costs that has already been reflected in the PACR analysis.

We consider this to be an extreme sensitivity.

Nonetheless, the results of this sensitivity reported in the figure below show that the South Australia – New South Wales Option C.3 is still preferred.

Figure 29 – Impact of assuming 25 per cent lower HVDC costs



We do not consider this sensitivity to be realistic, but include it for completeness.

170 ARCMesh, p.8.

8.6.4 Higher New South Wales coal prices

We have investigated a sensitivity involving $6.80/GJ black coal fuel costs for New South Wales generators, as suggested by Delta Electricity, which is significantly higher than the ISP forecasts.[171]

This sensitivity has been run solely for the preferred option to test whether this assumption affects the conclusion that this option is expected to deliver strongly positive net market benefits.

This sensitivity has not been run for all options as the computational requirements and modelling run-times are substantial and a higher NSW coal prices is expected to only materially affect the South Australia – New South Wales interconnector options.

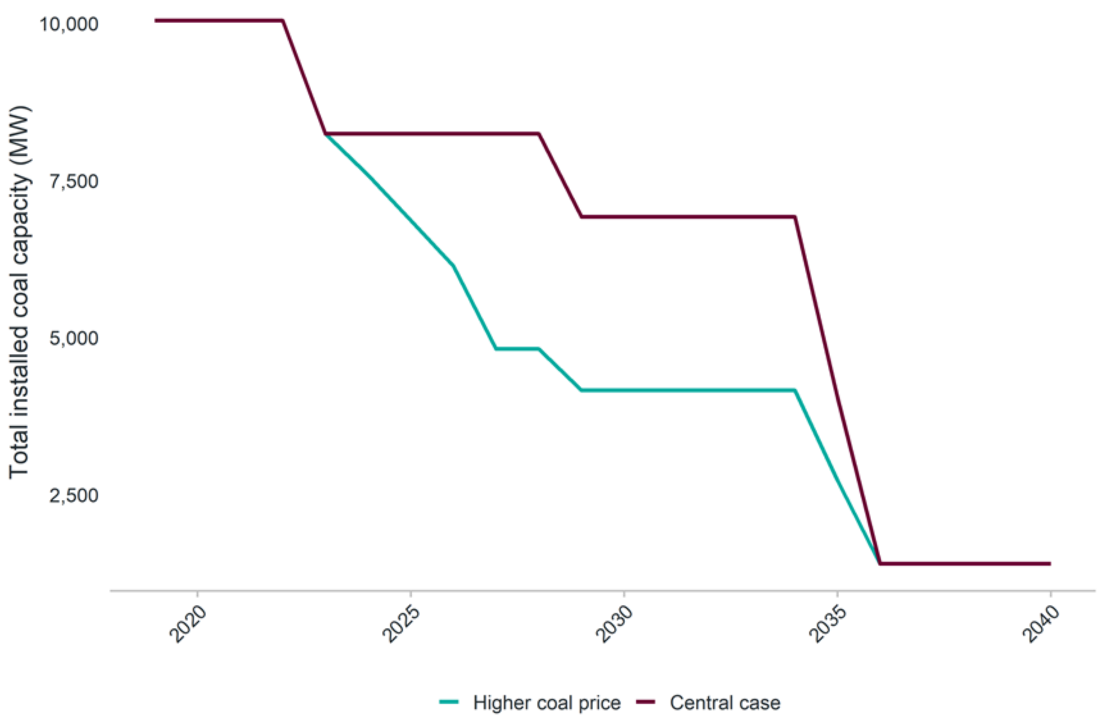
Running this sensitivity has found that the expected net market benefits of Option C.3 decrease by approximately $635 million under the central scenario to $130 million. As a consequence, Option C.3 continues to provide a market benefit even under this higher coal price assumption.

The decrease in estimated benefits is as a result of faster coal generator retirement in New South Wales and closing the gap between the costs associated with coal and gas generation. This is illustrated in the figure below, which compares the retirement of New South Wales coal generators under this sensitivity to the central scenario.

The benefits associated with offsetting gas generation in South Australia are lower than under the central scenario yet remain the largest single source of benefit. However, the interconnector also has a larger impact on avoided capital costs such as for new generation and transmission investments that would otherwise be needed.

[171] Delta Electricity, p. 2.

Figure 30 – Effect of assuming higher NSW coal prices on the retirement of NSW coal generators

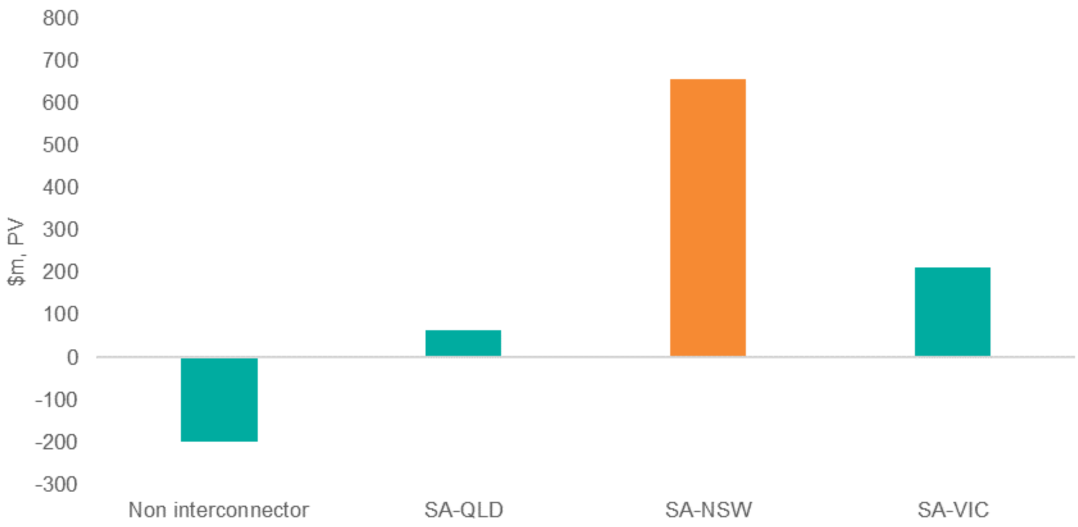


8.6.5 Shorter assessment period

The Energy Project submitted that the identified preferred option appeared sensitive to the selection of the assessment period and that adopting a shorter, 15-year, assessment period would result in a different preferred option. We outline the justification behind adopting the assessment period we have used in section 4.5.1 and Appendix F.

Notwithstanding, the figure below shows that the South Australia – New South Wales option (Option C.3) is still preferred even under this shorter assessment period.

Figure 31 – Impact of assuming a 15-year assessment period



8.6.6 Removing terminal values from the assessment

A number of parties have enquired about the use of terminal values in an economic assessment like a RIT-T and whether they affect the identification of the preferred option.

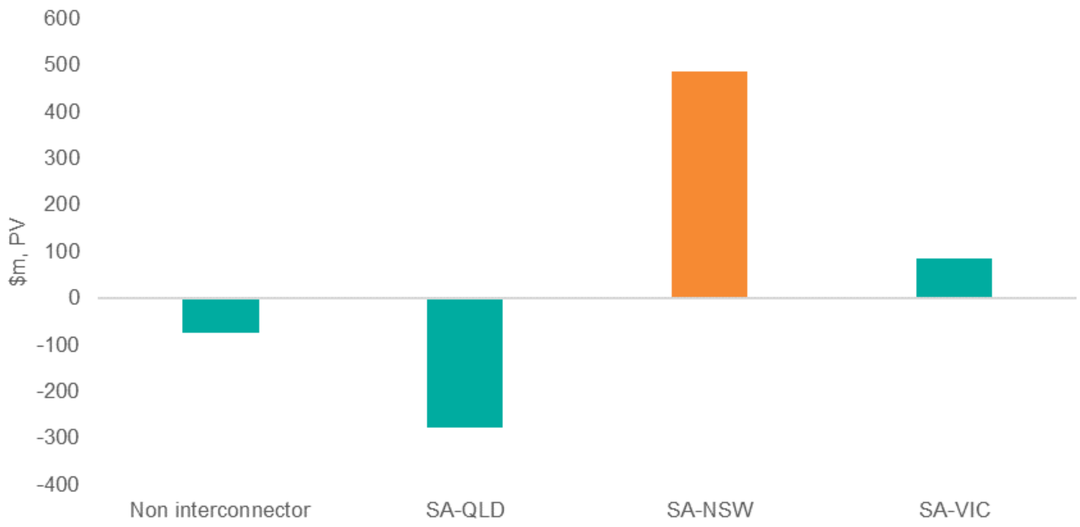
Appendix F outlines in detail how terminal values are common practice in assessments of this nature and recognise that, where options involve long-lived assets, these assets continue to have a value at the end of the assessment period. This ensures that the costs and the benefits are compared over the same period.

Notwithstanding, we have investigated a sensitivity test where the terminal values of all options are completely removed from the assessment. For clarity, this effectively compares the full cost of assets with long lives (eg, 50 years) with a benefit stream measured only over the assessment period (ie, 21 years). This is therefore considered an extreme sensitivity as it does not compare costs and benefits over a common period.

This sensitivity finds that, while the net market benefits fall for all options (on account of the full cost now being included), Option C.3 is still strongly preferred over the other options and has significantly positive estimated net market benefits, as shown in the figure below.

This fits with analysis summarised in Appendix F that shows that that costs of the preferred option will be completely recovered within nine years from energisation under the central scenario.

Figure 32 – Impact of removing terminal values from the assessment



8.6.7 All Torrens Island B units retire at or before 50-years of age under the base case

We have tested the effects of removing refurbishment and end of technical life assumptions on the South Australia gas plants.

These assumptions were applied to the black and brown coal plants in the core modelling and this sensitivity tests whether these assumptions are material assumptions for the selection of the preferred option.

We find that Torrens B retires in 2027 in the base case under this sensitivity, when it is 50-years of age. The table below summarises the retirement dates of all Torrens B units under this sensitivity and the central set of results.

Table 10 – Sensitivity of net market benefits to Torrens Island B retirement – retirement years

Generators	Scenarios			
	Central – Base case	Central – Option C.3	Sensitivity – Base case	Sensitivity – Option C.3
TORRB1	2025	2023	2025	2023
TORRB2	2031	2023	2027	2023
TORRB3	2032	2023	2027	2023
TORRB4	2033	2023	2027	2023

Pelican Point and Osborne do not reach 50 years before 2040 and hence continue to operate until 2040.

This sensitivity reduces the expected net market benefit of Option C.3 by approximately $240 million, reducing the fuel cost benefit by $170 million and the avoided fixed operating costs by $70 million.

This sensitivity has not considered the possible avoidance of capital associated with the replacement of Torrens Island B later in the horizon and so, as such, this is considered a conservatively high estimate of the reduction in benefit.

8.6.8 Assuming Pelican Point and Osborne are unaffected by a new interconnector

To extend the investigation of the robustness of the preferred option to the assumptions regarding the operation of South Australian gas plants, we have also run a sensitivity that assumes a new interconnector has no impact on the operation of Pelican Point and Osborne (ie, they do no retire nor change their behaviour).

That is, the operation of the two units once a new interconnector is energised is assumed to be the same as in the base case. This is considered a highly conservative sensitivity.

With these assumptions in place, the expected net market benefits reduce by approximately $595 million, but the preferred option still delivers significant net market benefits (of around $170 million under the central scenario). The estimated fuel cost saving is found to reduce by approximately $1.1 billion, which is partially offset by a reduction in storage costs of around $500 million.

9. Conclusion

The RIT-T assessment shows that a new 330 kV HVAC interconnector between Robertstown in South Australia and Wagga Wagga in NSW, via Buronga, together with a 220 kV augmentation between Buronga and Red Cliffs in Victoria is expected to deliver the highest net market benefit in the majority of scenarios and sensitivity tests, as well as under the weighted assessment.

This means that Option C.3 has been found to satisfy the RIT-T as the preferred option.

This option is scoped to provide 800 MW of transfer capacity and to increase transfer capacity on the existing Heywood interconnector to 750 MW, while delivering combined transfer capacity modelled at 1,300 MW. This is in addition to the existing transfer capacity of Murraylink (approximately 200 MW) which is 'firmed up' by the augmentation associated with the preferred option.

The key components of this option are as follows:

- a new 330 kV double circuit HVAC line between Robertstown and Buronga;
- a new 330 kV double circuit HVAC line between Buronga and Darlington Point;
- a new single circuit 330 kV HVAC line between Darlington Point and Wagga Wagga;
- a new 330 kV substation at Robertstown, including two 275/330 kV transformers at Robertstown;
- new 330 kV Phase Shift Transformers at Buronga (in order to share power transfers between new and existing interconnectors);
- two 330/220 kV transformers at Buronga;
- augmentation of existing substations at Robertstown, Buronga, Darlington Point, Wagga Wagga and Red Cliffs;
- a new double circuit 220 kV line (conductor strung on one side and operated as a single circuit) from Buronga to Red Cliffs in Victoria;[172]
- turn in the existing 275 kV line between Robertstown and Para into Tungkillo;
- static and dynamic reactive plant at Robertstown, Buronga and Darlington Point; and
- a Special Protection Scheme (to detect and manage loss of either interconnector).

This option remains as specified in the PADR, with the exception of the addition of a new 24 km 220 kV line from Buronga to Red Cliffs in Victoria and removal of series compensation.[173]

---

172 Appendix E summarises the economic assessment undertaken by AEMO regarding implementing the Red Cliffs to Buronga augmentation, which includes their assessment that having this strung as a double circuit line will provide additional net market benefits over a single circuit line by allowing future expansion.

173 Turning the existing 275 kV line from Robertstown to Para into Tungkillo is also new since the PADR, but has a minor cost associated with it (approximately $5 million).

The PADR flagged that the addition of this component would facilitate the connection of additional solar capacity in western Victoria, providing increased access to the Sydney and Adelaide load centres.

Capital costs for this option are estimated to be in the order of $1.48 billion across both South Australia and New South Wales, with a further augmentation between Buronga and Red Cliffs costing $46 million across New South Wales and Victoria. The total cost of this option is $1.53 billion.

The new interconnector is estimated to deliver net market benefits of around $900 million over 21 years (in present value terms), including wholesale market fuel cost savings in excess of $100 million per annum as soon as the interconnector is energised.

This puts 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 about $66 in South Australia and $30 in New South Wales, and an annual reduction for small business customers of around $132 in South Australia and $71 in New South Wales.

The scenario and sensitivity analysis presented in this PACR confirms that this option will provide material market benefits over a wide range of potential future outcomes for future gas prices, emissions policies, demand outcomes and capital costs.

Moreover, under the central scenario, we find that the market benefits realised from the investment are expected to exceed the investment cost (in NPV terms) nine years from energisation. Put another way, we estimate that costs of the preferred option will be completely recovered within nine years from energisation.

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.

Construction is expected to require two years, once all necessary environmental and development approvals have been obtained, with energisation possible between 2022 and 2024.

However, given the benefits that will be obtained as soon as the new interconnector is in place, we are working closely with the South Australian Government and TransGrid to undertake pre-approval works to bring forward the completion timeframe of the project as soon as possible.

The South Australian Government's underwriting of early works and the agreed framework for cooperation between the South Australian and New South Wales Governments increases the likelihood of achieving a 2022 delivery date.

ElectraNet and TransGrid have launched Project EnergyConnect to deliver the new interconnector, subject to obtaining all regulatory approvals. More information, including status updates, are available on the Project EnergyConnect website at www.projectenergyconnect.com.au.

APPENDICES

This page is intentionally blank

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.

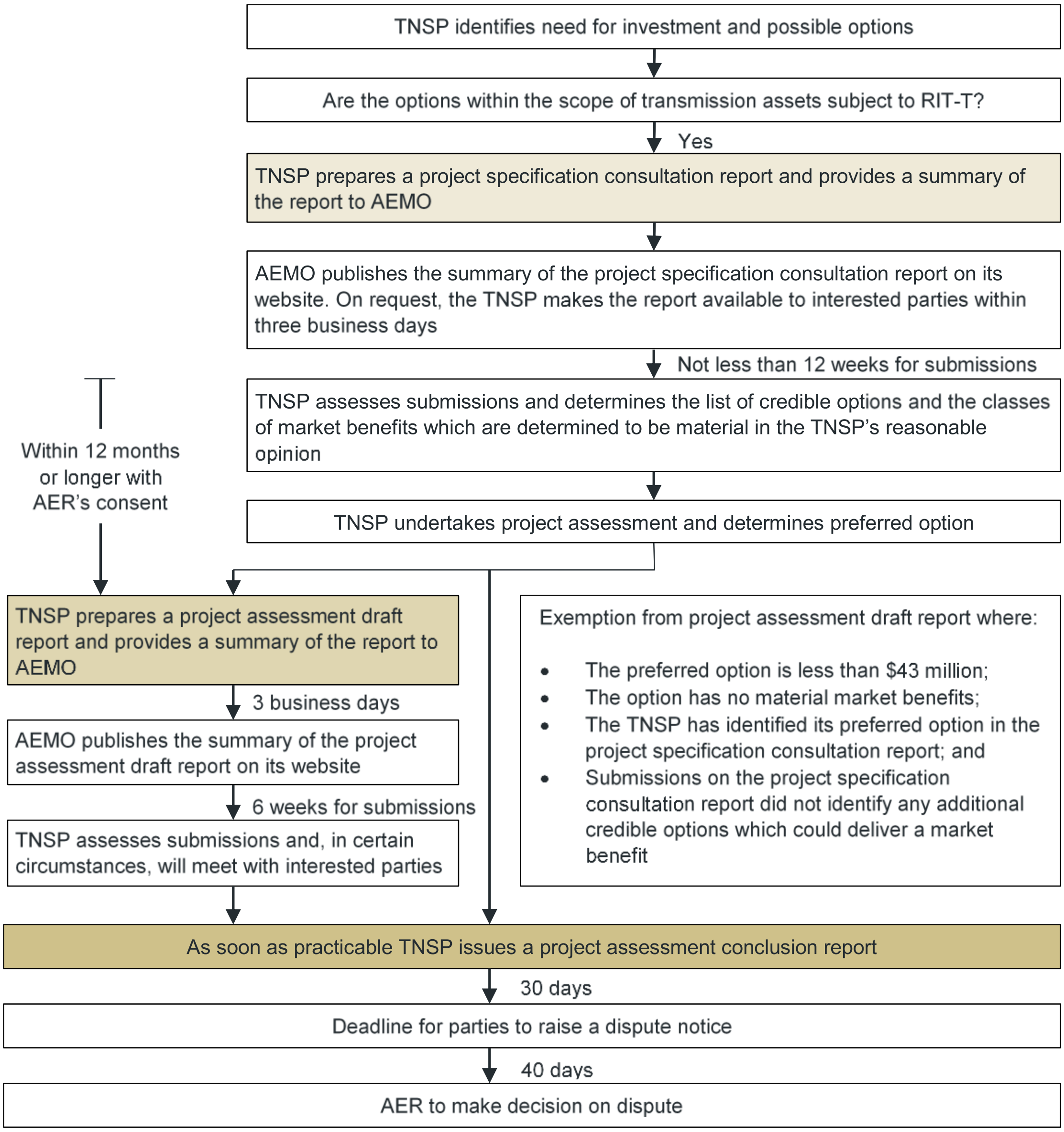
A comprehensive list of applicable regulatory instruments is provided in the Rules.

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 33 – RIT-T process



Appendix C Summary of consultation on the the PADR

This appendix provides a summary of points raised by stakeholders during the PADR consultation process, ie, the formal submissions received on the PADR, discussions had at separate public forums and deep dive sessions held in Sydney and Adelaide, as well as other engagement and communications with stakeholders outside of these processes.

The points raised are grouped by topic and a response is provided to every point raised. All section references are to this PACR, unless otherwise stated.

In addition, we have prepared separate appendices responding to:

- the additional incremental benefits of the Buronga to Red Cliffs augmentation – Appendix E;
- issues raised by The Energy Project (and other respondents that refer to The Energy Project analysis) – Appendix F; and
- the issues raised by ARCMesh – Appendix G.

Table 11 – Summary points raised in consultation on the PADR

Summary of comment(s)	Submitter(s)	ElectraNet response
Operation of SA gas-fired generators		
Assumed operation and retirement dates for SA gas-fired generation		
ElectraNet has not sufficiently considered, or presented in the modelling, the commercial realities of the remaining synchronous generation. Engie considers that additional information on the economic viability of SA gas plants must be made available in order to demonstrate that the claimed benefits are in fact achievable and are not reduced by additional cost to customers (eg, through requiring them to operate to provide local frequency control and inertia in SA). Further clarity around the difference in generator retirements in SA between the ISP and the PADR modelling is required.	EnergyAustralia, p. 3[174] & Engie, pp. 3-4.	Section 4.1.1 provides additional detail on the assumed operation of SA gas plants going forward, including the interaction with the ISP assumptions. In addition, by design, the operation of the new interconnector is constrained below the notional capability of the interconnector to manage the non-credible loss of the Heywood interconnector (and vice versa). This makes isolation of South Australia from the NEM a low probability event. Hence the requirement for local inertia or frequency control will be extremely rare. The inertia gap declared by AEMO in the 2018 NTNDP applies only at times of credible risk of separation and/or actual separation from the NEM. Credible separation would occur during infrequent storm events or a prior outage of transmission elements. After the completion of an additional interconnector via a diverse route, these conditions are not expected to occur. Separation would continue to be active considerations for AEMO were the non-interconnector option to be deployed.

[174] This was also raised by EnergyAustralia at the Sydney deep dive session on 16 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
The modelling of OCGT generators assumes slow start generators and ignores the potential benefits of fast start technology that is available from aero derivatives and reciprocating technology. These generators are likely to increase the efficiency of responding to price spikes and accounting for these types of generators entering the market could affect the economics of the preferred interconnector option by lowering overall prices within SA.	Origin Energy, p. 1.	The market modelling dispatches generators to meet the supply/demand balance in each region. The modelling is indifferent between existing or new generators and assumes plants are dispatched according to cost. It is not expected that the cost efficiencies of existing and new generators (including those outlined by Origin Energy) are materially different. The economics of the interconnector is not driven by price volatility, rather the resource costs of meeting supply and demand over the longer term
Questions whether the closure of TIPS B has been modelled.	EUAA[175] & AGL[176]	The modelling predicts TIPS B will retire once a new interconnector comes on line, whereas TIPS B is assumed to retire later under the base case. Some of the avoided gas fuel consumption comes from this. This lost capacity is replaced by increased import capability, and reduced requirements for local dispatchable capacity in SA.
Accounting for the impact on hedging services		
Further explanation is required of how the 100 MW uplift in the Heywood interconnector's capacity as a result of a new interconnector could likely be relied upon by generators looking at options to hedge firm between states.	Business SA, p.1.[177]	Section 4.1.2 and the accompanying CQ Partners report outlines how the ability to utilise both interconnectors for hedging, along with utilising settlement residue auction units and also local utility scale storage plus peaking gas generators, will assist in the ability of parties to manage spot price risk.
A new interconnector has the potential to make the current unavailability of hedging contracts in SA worse and should not be ignored. The non-interconnector option is expected to increase (or at least preserve) local dispatchable generation in SA and hence the supply of hedge contracts.	EnergyAustralia, p.4.	Section 4.1.2 and the accompanying CQ Partners report outlines how a new interconnector will help with the current difficulties in obtaining hedging contracts in SA.
If investment proceeds with an expanded interconnector capacity, then generators plan to invest to offer firming capacity in South Australia.	Confidential	This accords with the analysis undertaken by CQ Partners, which is discussed in Section 4.1.2 of this PACR.

[175] This was raised by EUAA at the Adelaide deep dive session on 17 August 2018.

[176] This was raised by AGL at the Sydney deep dive session on 16 August 2018.

[177] This was also raised by Business SA during the Adelaide Public Forum on 18 July 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
The impact on system security and reliability needs		
Query the decision not to explicitly model FCAS benefits given these costs have been the cause of significant price spikes across SA over the past 5 years, growing from $5 million per annum to above $50 million per annum.	MEA Group, p. 1.	FCAS (and other ancillary services) have been considered as part of this RIT-T but are not expected to be material in terms of identifying the preferred option. Specifically, all interconnector options are expected to lower FCAS costs but this is not expected to be material (in either the difference *between* options, or relation to the other categories of market benefits estimated). Appendix D provides more detail. Recent changes to the operation of the market, enabled by new dispatchable capacity in South Australia have already significantly reduced the cost of FCAS in South Australia. Provision of contingency FCAS is of low resource cost, whilst the market prices may not always reflect this. The RIT-T is restricted to considering the resource costs only. A change in cost of FCAS will not materially alter the requirement for FCAS
Including storage along the path of the preferred option can improve interconnector capability and provide FCAS services.	Renew Estate, p. 2.	This may be correct, but it has not been captured in the analysis since changes in FCAS costs are not expected to be material in terms of identifying the preferred option. Appendix D provides more detail. Batteries and other investments that may further support interconnection are not prevented from development later as a result of this RIT-T if they drive sufficient market or commercial benefits in their own. Batteries at strategic locations can also provide a direct uplift to the combined interconnector transfer capacities. AEMO has explored a battery solution along these lines in the Western Victoria Renewable Integration RIT-T and found negative benefits for such an investment.[178]

[178]AEMO, Western Victoria Renewable Integration RIT-T, December 2018, pp. 7.

Summary of comment(s)	Submitter(s)	ElectraNet response
The assumed retirement of SA gas plants once the interconnector is built suggests that the identified need of security may not be fully satisfied by the project. Delta Electricity suggests that an explicit scenario involving these plants shutting down should be assessed, as well as the cost of maintaining system security and reliability if a SA to NSW interconnector trips (eg, through AEMO's RERT response).	Australian Energy Council, p. 2 & Delta Electricity, pp.2-3.	Section 3.3 outlines how all options considered can provide benefits from enhancing security of supply in SA. Section 8.5 presents the impact on the assessment from assuming differences in the assumed dates for SA gas plant retirement, compared with the technical retirement dates adopted in the ISP.
The three REZs the preferred option crosses are not attractive for renewable energy projects such as Concentrated Solar Power (CSP), that can bring system resilience benefits, such as inertia and dispatchability. The preferred option is unlikely to attract renewable energy that can provide inertia or grid support services. The AEMO REZs do not recognise the different resource requirements between PV and CSP or the benefits of CSP.	SolarReserve, p. 4.	ElectraNet is responding to a system strength gap in South Australia, declared by AEMO[179]. AEMO has also declared an inertia gap in South Australia in the 2018 NTNDP.[180] Both the above gaps are being progressed outside of this RIT-T. Given the rapid change in generation mix, especially in SA, these system aspects will be the focus during AEMO and Electra Net's routine planning work.
Queries how the system strength cap has been modelled.	EnergyAustralia[181]	The cap on non-synchronous generation has been modelled. Details of the non-synchronous cap can be found in the network technical assumptions report. The base case requirement is for four synchronous machines. Two are supplied by synchronous condensers at Davenport and two synchronous generators in the PACR. There was a two synchronous generation unit requirement assumed in the PADR.

[179] https://www.electranet.com.au/what-we-do/projects/power-system-strength/

[180] AEMO, 2018 NTNDP, December 2018, pp. 4-5.

[181] This was raised by EnergyAustralia at the Sydney deep dive session on 16 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
The impact that additional interconnection will have on both new investment and early retirement of generators needs to be examined, especially as it relates to system security.	Origin Energy, p. 3 & EnergyAustralia, p.2.	The wholesale market modelling assesses both the impact on new investment and the retirement of generators. We have also investigated the sensitivity of the results to earlier than assumed gas generator retirement, as outlined in section 8.5. The plausibility of replacement decisions has also been explored and found to be reasonable. In addition, all interconnector options considered will improve system security since they have been scoped in such a way that a non-credible loss of either HVAC interconnector can be survived without disconnecting South Australia from the NEM. This alleviates the risk of low inertia system, as low inertia is relevant only during and after a complete separation event.
Encourage ElectraNet to ensure that the inertia assumptions align with AEMO's inertia assumptions for the future solution (and, in particular, that the assumed inertia level is not low relative to AEMO's modelled requirement).		
The identified need should not include enhancing the system security as this has been addressed in recent market developments and rule changes.	EnergyAustralia, p.2.	This is acknowledged and the assumptions for the base case have been updated since the PADR to reflect the latest status of system strength and inertia work up until December 2018. Section 3.3 outlines how all options considered can provide benefits from enhancing security of supply in SA. Specifically, it outlines how options can contribute to meeting system security standards in SA at a *lower cost* than would otherwise be the case.

Summary of comment(s)	Submitter(s)	ElectraNet response
ElectraNet should provide clarity on additional interconnector benefits after removing the non-synchronous cap and RoCoF limits in the base case.	EnergyAustralia, pp.2, 6 & 7.[182]	The cap on non-synchronous generation has been modelled. Details of the non-synchronous cap can be found in the network technical assumptions report. The RoCoF constraint will continue to constrain the Heywood interconnector based on the amount of inertia online for import conditions to limit the rate of change of frequency in a non-credible contingency scenario. A new interconnector alleviates 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. We do not consider it credible to remove the non-synchronous cap and RoCoF limits from the base case. The non-synchronous cap is a market constraint imposed by AEMO, while the RoCoF limits are required by the South Australian Government. However, the base case will reflect the level of binding of these constraints in the modelling.

[182] This was also raised by EnergyAustralia at the Sydney Public Forum on 16 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
It is not clear if the Entura modelling has considered other market developments such as changes to the generator technical performance standards and the do no harm component of the managing power system fault level rule change. Entura has also not identified whether further fault level and or voltage regulation requirements will still likely be required adding additional costs to the interconnector option.	EnergyAustralia, p.4.	Entura investigated a non-interconnector option that does not involve a new interconnector. This planning study did not cover detailed connection requirements, which could only add costs to the non-interconnector solution. Doing so would further reduce the economic viability of this option. In terms of further fault level and/or voltage regulation requirements, Entura have confirmed that the base case is assumed to be required for both the non-interconnector option and also for all the new interconnector options. The base case includes new synchronous condensers providing inertia, fault level and voltage regulation. The cost of these proposed machines is excluded from the estimates of both the non-interconnector option, and all the new interconnector options. Further, a new interconnector will significantly reduce the risk of islanding and therefore inertia related requirements, while also contributing to system strength. However, any local system strength issue in the future will be addressed on a as needs basis
What impact will a new interconnector have on system security and the need to maintain the minimum inertia requirement, especially in islanded situations.	Origin Energy, p. 3.	All interconnector options considered will improve system security since they have been designed in such a way that a non-credible loss of either HVAC interconnector can be survived without disconnecting South Australia from the NEM. Specifically, combined transfer limits lower than notional limits have been applied to ensure that the islanding risk is minimised.

Summary of comment(s)	Submitter(s)	ElectraNet response
ElectraNet has assumed that sufficient infrastructure will be installed outside of this RIT-T to raise the current system strength constraint on inverter connected generators from 1,295 MW to 1,875 MW without providing adequate justification for that assumption.	Tilt Renewables, p.1.[183]	The modelling assumes that minimum system strength requirements are met when considering both new interconnector and non-interconnector options (as outlined above, the base case requirement is for four synchronous machines). Meeting these requirements will increase the amount of non-synchronous generation that may be online in SA, however, some limits on non-synchronous generation are still expected. In addition to alleviating the 1,295 MW cap on non-synchronous generation, the credible options considered in this RIT-T improve system security by alleviating the RoCoF constraint operating on the existing Heywood Interconnector. ElectraNet's PADR modelling assumed that the minimum system strength requirements that AEMO has specified apply today and are met. The RIT-T assessment then determines whether there is any economic merit in increasing system strength further in order to lift limits on non-synchronous generation.

[183] This was also raised by Tilt Renewables during the Adelaide Public Forum on 18 July 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
Interested in the effect of a new interconnector on the system protection scheme in SA and the cost implications, in light of more renewable generation entering the SA market.	ESCOSA[184]	AEMO has specified that a special protection scheme is required in SA. ElectraNet has implemented this emergency control scheme. AEMO in its Power System Frequency Risk Review published in June 2018 has recommended that an augmentation to the current scheme be considered and we are working with AEMO in developing this scheme. A new interconnector will dramatically reduce the risk of a situation arising in which the existing scheme is needed to operate. While the scheme will still be needed with a new interconnector in place, triggering will be primarily based on detection of loss of either interconnector. The special protection scheme is a low-cost measure to enhance system security via an emergency protection scheme.
Interested in understanding the linkage between savings in gas generation under AC v DC options and the associated benefits and costs.	ARCMesh[185]	Gas generation savings are similar in magnitude. There is no difference in the way AC v DC interconnectors address the system security constraints in South Australia. In order to address system security constraints and to ensure the modelled operation of the AC interconnectors, a range of other costs are incurred in the AC options to provide various supporting equipment required to meet broader system security requirements. RoCoF constraints are also assumed to fall away with all interconnector options including DC despite DC having some differences in the way this is achieved, and hence delivering associated benefits.

[184] This was raised by ESCOSA during the Adelaide Public Forum on 18 July 2018.

[185] This was raised by ARCMesh at the Adelaide deep dive session on 17 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
HVDC inverters can respond with system strength. A DC option with early installation of converters would solve the immediate system strength problem.	ARCMesh[186]	The current system strength shortfall in South Australia needs to be addressed urgently and cannot wait for the development of a new interconnector. Synchronous condensers are needed urgently now whether a new AC or DC link is ultimately built, and are planned to be in place by 2020. It is worth noting that for HVDC VSC systems to provide system strength similar to synchronous generators, the HVDC VSC system has to be oversized and also have a suitable energy source on the DC side. This would not be the case before the DC link between South Australia and Queensland is built.
With the system strength gap declared, synchronous condensers will be required and are being pursued in three SA locations, but synchronous condensers are also being included in the preferred option.	ARCMesh[187]	ElectraNet is addressing the declared system strength gap outside of this RIT-T process. ElectraNet has recommended to AEMO that four large synchronous condensers will meet the system strength gap. These synchronous condensers are needed in SA urgently and are assumed in the base case. They are no longer assumed in the preferred option.
Queries whether a RIT-T is required for the short-term synchronous condensers.	ARCMesh[188]	The short-term synchronous condenser project is exempt from the RIT-T under the Rules given its urgency. However, ElectraNet is required to undertake an equivalent economic assessment and will continue to engage with stakeholders in relation to this assessment.

[186] This was raised by ARCMesh at the Adelaide deep dive session on 17 August 2018.

[187] This was raised by ARCMesh at the Adelaide deep dive session on 17 August 2018.

[188] This was raised by ARCMesh at the Adelaide deep dive session on 17 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
Feedback on the market modelling approach and assumptions		
Higher NSW coal prices should be tested		
Assumed coal prices are too low for NSW and should be at least $1.50/GJ higher to align with current export parity.	Delta Electricity, p.2.	Section 4.2.1 summarises how we have included a new sensitivity with higher coal prices. Section 8.5 presents the results of this sensitivity.
Assumed coal prices are too low and additional sensitivity analysis to higher coal prices is required. It would appear necessary to test results at coal prices of at least $5.00/GJ.	SEA Gas, p. 3.	
It is unclear what consideration has been given to legacy coal contracts coming to an end, and the consequent increasing linkage between international and NSW coal prices. Similarly, the impact of any potential LNG import terminals in the southern states is a reasonable scenario that should be considered given recent proposals for such projects.	Origin Energy, p. 1.	Section 4.2.1 summarises how we have included a new sensitivity with higher coal prices. Section 8.5 presents the results of this sensitivity. A separate scenario for the impact of any potential LNG import terminals has not been developed since Australian gas prices are now linked to export prices. Therefore any such terminal is not expected to affect the long-run price of gas. Specifically, while there are reported gas prices being offered in excess of export parity currently, this is not expected to persist in the long-term.
If a coal plant in NSW or QLD retires earlier than anticipated, the subsequent benefit to consumers, will not occur for as long as modelled. The impact of early retirement of coal plants should be examined.	Origin Energy, p. 2.	Section 4.2.1 summarises how we have included a new sensitivity with higher coal prices, which affects the owners' decision to retire these plants. Section 8.5 presents the results of this sensitivity.
Consistency of the 'REZ benefit' with the RIT-T framework		
The Queensland option passes close by the Broken Hill REZ and, more generally, crosses some high quality solar resources that, without this interconnector would not be considered as possible REZs. ElectraNet should consider reviewing the value of a new REZs for this option and the overall market benefit that this would provide.	SolarReserve, p. 5.	ElectraNet notes that the PACR assessment does include this benefit for the Queensland route but notes that, due to the HVDC technology, it requires additional mid-point converter stations, which are expensive. The specific REZ that is picked up by the Queensland route is near Broken Hill in New South Wales. See Section 4.2.2.

<table>
<tr><th>Summary of comment(s)</th><th>Submitter(s)</th><th>ElectraNet response</th></tr>
<tr><td>These benefits cannot be properly measured and assigned in the current RIT-T framework. If this category of market benefit is excluded, the QLD option becomes the preferred option in the central scenario (but the weighted results affirm C3i as the preferred option).</td><td>The Energy Project, p. 21, TEC, p. 2[189] & PIAC, p. 1.[190]</td><td>Section 4.2.2 outlines the legitimacy of these avoided transmission costs in the context of the RIT-T framework. Appendix F provides a detailed response to all points raised by The Energy Project.</td></tr>
<tr><td>Queries which REZs are assumed to be developed.</td><td>The Energy Project.[191]</td><td>In the PACR, these are found to develop progressively based on criteria developed in the ISP which includes quality of resource, proximity to the network, capability of the network, and regional diversity of resources.

ISP Group 1 projects have been assumed which results in the strengthening of VNI and QNI however, these projects do not unlock REZs.

The western Victoria renewables RIT-T is assumed which develops the Western Victoria REZ.</td></tr>
<tr><td>Deferral of REZ transmission works are speculative and should be excluded from the assessment. Delta Electricity suggests that transmission deferrals only be contemplated for approved projects.</td><td>Australian Energy Council, p. 3, Delta Electricity,[192] p. 5 & EnergyAustralia, p.6.</td><td rowspan="2">Section 4.2.2 outlines the legitimacy of these avoided transmission costs in the context of the RIT-T framework.</td></tr>
<tr><td>Should ElectraNet and TransGrid consider that the market benefits relate mostly to its potential long-term role in facilitating a REZ in southwest NSW, they should pursue changes to the RIT-T framework to ensure that these benefits can be adequately internalised.</td><td>TEC, p. 5.</td></tr>
</table>

189 References The Energy Project submission in making this point.

190 References The Energy Project submission in making this point.

191 This was raised by The Energy Project at the Adelaide deep dive session on 17 August 2018.

192 This was also raised by Delta Electricity at the Sydney deep dive session on 16 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
Additional detail on the specific REZ transmission costs that are assumed to be avoided should be provided, as well as an explanation as to why the Queensland and Victorian interconnector options do not avoid any such costs.	AusNet Services, p. 3,[193] MEA Group, p. 1 & TasNetworks.[194]	The ISP assumptions have been adopted, whereby renewables close to the network connect without incurring transmission cost, after which the penalty cost of unlocking more distant renewable generation is factored into the modelling. This provides the source of the avoided transmission investment benefit captured by the interconnector options. The SA-NSW link defers some of this assumed investment. In the PACR Option B has included costs and benefits of connecting to the Broken Hill REZ. In the PACR, Option D has been assumed not to further unlock the western Victoria REZ. This REZ is being unlocked by the Western Victoria Renewable Integration RIT-T. Option D will provide generation within this zone access to the Adelaide load centre only which is already well served by renewables. This option differs from other interconnector options in that it only provides increased access to Adelaide, other interconnector option increase access to other load centres: namely Sydney and Brisbane. This renewable zone is rated by AEMO as having a D rating on diversity and in particular is only moderately diverse when compared to almost all of South Australia's 9 renewable energy zones.
Treatment of uncertainty in relation to renewable policies and emissions outcomes		
Closing coal plants will be replaced by renewables and gas and so most of the benefits identified will not materialise as the alternate fuel supply being gas should cost the same across SA, NSW and Victoria.	CIT, p. 1 & Delta Electricity, p. 1.	Section 4.2.3 outlines how we have used fuel cost and technology curves from AEMO and tested sensitivities to these. An increasing role for gas is taken into account in the economic modelling.

[193] This was also raised by AusNet Services at the Adelaide deep dive session on 17 August 2018.

[194] Raised during the Adelaide Public Forum on 18 July 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
In the short-term, additional interconnection appears to result in an increase in emissions as lower emission mid merit gas generation is displaced by cheaper and more emission intensive black coal generation from NSW and Queensland. Additional detail around the trajectory of the actual emission benefits is required.	EnergyAustralia, p. 6 & TEC, p. 3.	Section 4.2.3 outlines how the market modelling includes compliance with emissions limits consistent with Australia's COP 21 commitments as a constraint in the central scenario, which means that all outcomes modelled have emissions levels that are consistent with these targets in this scenario. In addition, we have also reported as part of the results the carbon emission quantities associated with each option (these have been released alongside this PACR).
The cost of additional emissions needs to be valued and not left as an externality.	Engie, p. 4.	This is not allowed under the RIT-T framework. However, we do assess the impact of assuming a higher national emissions commitment as a sensitivity, as shown in section 8.5.
The preferred option should be investigated to consider the impact on sectoral emissions.	Australian Energy Council, p. 2.	The RIT-T is clear that only the costs to the NEM of meeting emissions targets are to be included. Any second-order sectoral impacts sit outside of this framework.
There is no discussion of whether diversity in renewable energy output has been modelled across regions. The Queensland options provide SA direct access to renewable energy from a region with very different energy production characteristics in terms of weather patterns and solar profiles.	CIT, p. 1 & ARCMesh, p. 22.	Diversity over the time frames considered is taken into account in the modelling. ElectraNet has adopted AEMO's ISP assumptions in relation to wind diversity. The ISP assessed in great detail the diversity of renewable resources and their ability to demand-match (please refer to Appendix A of the ISP for more detail on the correlation between renewable resources across NEM). Further, the Queensland HVDC option requires very expensive connection costs for each tap into the HVDC lines.

Summary of comment(s)	Submitter(s)	ElectraNet response
It is too early to make a judgement call on such infrastructure spend while the generation industry is in a state of transition and flux. AEC consider that the high degree of current uncertainty in the NEM should skew the preferred option to cheaper solutions that do not expose so much capital to the risk of the future not playing out as forecast, or encourage the assessment of investment options which are staged to allow a smaller network investment in the short-term, with the flexibility to upgrade at reduced cost later, once the future becomes more certain.	CIT, p. 2 & Australian Energy Council, p. 2.	The treatment of uncertainty is dealt with in the RIT-T through the construction of reasonable scenarios, as outlined in section 7.1. Investment decisions cannot continually be deferred in light of such uncertainty, as it will always exist. Section 4.4 discusses the scope for staging the interconnector investment and Table 6 summarises why we do not consider a staged development feasible. Developments in new generation along the corridor are demonstrating the value of the preferred option immediately. Generator commitments along the corridor have exceeded the PACR assumptions on the preferred options capacity to support future developments. These generator projects are committed and will be deployed ahead of the preferred option.
It is not clear that a new interconnector will lead to the early closure of gas plants in SA as such a scenario depends upon a number of factors which may change in the interim. The SA Government's decision to pay the owners of Pelican Point to reopen it after the blackout in 2016 to increase system security is just one example of the potential for political as well as economic interventions which may have profound market impacts.	TEC, p. 3	We have aligned our assumptions regarding the operation of these plants with those in the ISP. We have also tested a sensitivity, which is presented in section 8.5.3. A confidential submission has stated that major investment in renewables and storages require that the interconnector be built to provide greater access to the eastern states. Submissions such as these, along with the actual developments along the corridor of the preferred option demonstrate the value of increased interconnection.
The modelling has included the QRET and the VRET but has not included the SA Energy Target. The NEG Reliability Requirement has also not been included.	Australian Energy Council, p. 3 & Engie, p. 1.	See Section 4.2.3.
It is assumed that the NEG is implemented, this should now be adjusted based on recent events.	Origin Energy, p.1	See Section 4.2.3.

Summary of comment(s)	Submitter(s)	ElectraNet response
A potential investor expressed an interest in substantial new wind generation development in SA if a new interconnector proceeds.	Confidential.	ElectraNet notes this submission and considers that this supports the findings of the market modelling that substantial change in South Australia is likely to eventuate following the delivery of the preferred option. ElectraNet has not explicitly modelled the details in this submission in the economic models.
Solar resources are very strong along a QLD interconnector route which would unlock more renewable generation development.	ARCMesh and CIT.[195]	The PACR analysis factored in the existence of known solar reserves, based on inputs from the ISP. The costs and benefits of unlocking the Broken Hill REZ were included in Option B. The ISP has undertaken a detailed analysis of renewable energy resources and identified the most prospective renewable energy zones, including the impacts of diversity in the analysis. Many good resources are located closer to the grid. The modelling also looked at resources along the interconnector route, and the relative strength of these resources was taken into account in all options considered.
Impact of high scenario on the RIT-T outcome		
Parameters such as a more stringent RoCoF limit and higher gas prices in the high scenario have resulted in an unrealistic outcome being reported.	Australian Energy Council, pp. 2-3.	Section 4.2.4 outlines how neither the PADR outcome nor the PACR outcome has been biased by the inclusion of the high scenario. The high scenario is intended to represent an 'upper end' of the envelope of potential outcomes against which the robustness of the RIT-T outcome is being tested. We therefore consider that it is appropriate that the high scenario includes upper end assumptions in relation to the various parameters and have continued to assume a high gas price. We have however modified the 'high scenario' to reflect the current 3 Hz/s South Australia inertia requirement.

[195] This was raised by ARCMesh and CIT at the Adelaide deep dive session on 17 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
It is not appropriate to apply all assumptions in the high scenario in the one scenario. These assumptions interact with each other leading to overstated benefits that are very unlikely to be representative of the upper reasonable bound of the benefits. It would also be beneficial to test in isolation the increased transfer capacity provided by additional interconnection separate to technical limits addressable by alternative means (i.e. removing RoCoF limits and low synchronous cap).	EnergyAustralia, p.6.	Section 4.2.4 outlines how neither the PADR outcome nor the PACR outcome has been biased by the inclusion of the high scenario. In addition, section 8.5 shows that the conclusions of this RIT-T are independent of the scenario weightings adopted, with the preferred option being the highest ranked option across all reasonable scenarios.
The assignment of probabilities to the scenarios that bias the result to a high NPV is considered far too subjective to underpin a $1.4 billion cost.	Engie, p. 3.	
Transparency around the modelling approach and results		
There is a lack of a detailed description of the method used to quantify each class of material market benefit and cost and it is suggested that more information transparency be provided.	Australian Energy Council, p. 3.	All costs and benefits have been quantified in accordance with the RIT-T framework and consistently with the ISP (where relevant). This PACR, and the various consultative sessions following the PADR, , as well as the additional documents released, expand on the methodologies employed.
There are insufficient modelling results published to allow stakeholders to confirm the conclusions. More detailed modelling results should be published along with a thorough assessment by AEMO of any impact on NSW import/export capability.	Delta Electricity, p.3.	We have published more detail on the modelling results alongside this PACR. AEMO's recent ISP undertook a thorough assessment of the impact on NSW import/export capability.
Failure to provide detailed modelling results severely impedes a meaningful review of this study by participants. The modelling results should be released as part of the consultation as a matter of priority.	Engie, p. 2.	We have released more modelling information than any RIT-T to-date. This includes numerous documents on the market modelling approaches and assumptions, the NPV models used, the data sheets behind the PADR figures and charts and generator expansion for all scenarios. We also undertook four consultative sessions with stakeholders following the release of the PADR, namely public forums and 'deep dives' into the modelling and assumptions in Sydney and Adelaide. Section 2 details the detailed consultation undertaken, and material released, as part of this RIT-T to-date, while Appendix J includes a list of supplementary reports and information, including market modelling information, released alongside this PACR.

Summary of comment(s)	Submitter(s)	ElectraNet response
Concerned about the lack of detailed results and the lack of clarity around some of the input assumptions that have been made, for example cycling of thermal units. Without providing clarity of assumptions around these technical characteristics of thermal units, the PADR modelling may be providing unrealistic dispatch outcomes and potentially overstating the benefits of fuel savings.	EnergyAustralia, pp.1-2.	We have published more detail on the modelling results alongside this PACR. ElectraNet published a 'Market Modelling and Assumptions Data Book' with the PADR, which published thermal plant cycling.[196]
The following should be included in the assessment: • market impacts that may occur due to the required major outages to parts of the network to facilitate upgrades which may constrain power flows on other parts of the network; and • market impacts from ongoing maintenance of interconnector(s). That is any flow limits on interconnectors to manage a post contingent loss of the remaining interconnector(s).	EnergyAustralia, p.7.	Section 4.1.2 outlines how these have been considered. The preferred option is largely a greenfield development and will have little requirement for outages. Once completed, operation under a prior outage will restrict the combined imports to South Australia to 850 MW, this is an 800 MW improvement on the existing outage operation of the network
An explanation is required for how the modelling has simulated the effect of a controlled loop around the NEM in market.	ARCMesh[197]	A controllable DC load-flow model has been used to represent the network including network limits, with hourly dispatch runs to simulate security constrained optimised dispatch across the interconnected network.
An explanation is required for how energy losses were modelled.	IES[198]	We have undertaken a 'DC Load Flow' model of the market which captures the impact of network losses. Power flows are included in the optimisation of dispatch subject to the resistance values of all lines in the model. The treatment of electrical losses is explained further in section 6.3.6 of the PADR.
Queried which direction of flow provides the most benefits and whether excess solar from SA is assumed to flow into NSW.	Red Energy[199]	There are 2-way flows, with the dominant flow being into South Australia initially, which then reverses over time. Excess generation in NSW initially flows into SA in the early years, before excess renewable generation in SA flows into NSW, particularly as its coal fleet retires.

[196] See the 'Market Modelling and Assumptions Data Book', released in June 2018: https://www.electranet.com.au/projects/south-australian-energy-transformation/

[197] This was raised by ARCMesh at the Adelaide deep dive session on 17 August 2018.

[198] This was raised by IES at the Sydney Public Forum on 16 August 2018.

[199] This was raised by Red Energy at the Sydney Public Forum on 16 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
Development of additional scenarios and sensitivities		
Additional assumptions and scenarios should be conducted, including: 1. an early closure of Yallourn Power Station 2. higher coal prices 3. the SA government fully implementing its policy to deploy up to 450 MW of residential batteries 4. AEMO determining a minimum amount of reliable dispatchable gas generation in SA 5. NSW implementing the equivalent of the VRET 6. early development of the 'battery of the nation'	Delta Electricity, p.4.	We have expanded the sensitivities and scenarios investigated in the PADR. Specifically, we have investigated additional assumptions suggested by parties in submissions that are expected to have a material impact on the assessment. These are listed at the end of section 7.3 and presented in sections 8.5 and 0
Queried whether early Victorian coal retirements have been modelled in the analysis.	AusNet Services[200]	
ElectraNet should broaden the analysis with different scenarios, rather than through sensitivity analysis since varying one assumption at a time will still present a picture of positive net benefits.	Delta Electricity, p.4.	A single variable is tested in each sensitivity case, allowing the effect of the variable to be conclusively derived. If this method is altered, where multiple variables are tested at the same time, it would not be possible to determine the effect of each variable individually. Most RIT-T assessments to date have adopted a one-at-a-time approach to sensitivity analysis. This is distinct from the scenario analysis undertaken, which is used to test the combined effect of a set of variables. The variables included in each scenario 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. The conclusions of this RIT-T are independent of the scenario weightings adopted, with the preferred option being the highest ranked option across all credible scenarios.

[200] This was raised by AusNet Services at the Adelaide deep dive session on 17 August 2018.

<table>
<tr><th>Summary of comment(s)</th><th>Submitter(s)</th><th>ElectraNet response</th></tr>
<tr><td>There should be consideration of a Snowy or no Snowy option in the modelling.</td><td>Origin Energy, p. 1.</td><td rowspan="4">At the time of this PACR, Snowy 2.0 is not a committed project, but has been identified as a Group 2 project in the ISP. Snowy 2.0 will not have a material impact on the ranking of the options.
The most likely option to be influenced positively by Snowy 2.0 is the preferred option. There is an increase in congestion between Canberra and Sydney following the completion of the preferred option. Snowy 2.0 is likely to result in an increase in the amount of transmission between Wagga Wagga and Sydney thereby alleviating congestion following energisation of the preferred option. This is expected to increase the benefits of the preferred option as a complementary development.
The goal of the RIT-T is to identify the preferred option and to rank options accordingly. This variable is not expected to change the preferred option or the ranking of the options, but to increase the benefits of the preferred option.</td></tr>
<tr><td>The timing of Snowylink North (the Snowy 2.0 to Bannaby section) of the southern NSW upgrades being prioritised and brought forward to coincide with the retirement of the Liddell Power Station in 2022 should be tested.</td><td>Snowy Hydro, p. 2.</td></tr>
<tr><td>The timing of the upgrades for Snowylink South (referred to as ‘Kerang Link’ in the ISP) being brought forward to no later than 2025 should be tested.</td><td>Snowy Hydro, p. 2.</td></tr>
<tr><td>Coordinating the timing of Riverlink and the ISP Southern NSW augmentations is required to fully realise integrated system benefits. To achieve this ElectraNet should include modelling for:
• delaying some sections of Riverlink by a couple of years,
• advancing some Southern NSW augmentations by a couple of years, and
• include firming capacity provided by Snowy 2.0.</td><td>Snowy Hydro, p. 2.</td></tr>
<tr><td>Supports conducting a more robust scenario analysis, calculating option values and developing and assessing reasonable scenarios of future supply and demand to ensure ElectraNet’s preferred option is prudent.</td><td>SACOSS, p. 2</td><td>We have thoroughly tested the robustness of the identified preferred option to key underlying variables and assumptions. Many of these tests have been conducted in response to points raised in consulting on this RIT-T.</td></tr>
<tr><td colspan="3">Bidding behaviour assumed</td></tr>
<tr><td>Modelling should use realistic bidding, rather than Short Run Marginal Cost (SRMC) bidding, since the benefits are largely based on cost advantages. In addition, generator commercial outcomes should also be assessed, based on profitability, for all scenarios since assumed closure dates are critical to the benefits.</td><td>Delta Electricity, pp.4-5.</td><td>SRMC is standard practice in projection generation and investment requirement in wholesale electricity markets and is a requirement of the RIT-T.[201] Similar approaches have been utilised by AEMO in their latest ISP, previous NTNDPs and RIT-Ts and ElectraNet in the Heywood interconnector RIT-T which have all assessed the relativities of alternative network investments</td></tr>
</table>

[201] AER, Regulatory Investment Test for Transmission, June 2010, pp. 8-9.

Summary of comment(s)	Submitter(s)	ElectraNet response
Updated underlying assumptions since the ISP was released		
Solar PV and battery penetration projections have been updated since the ISP and used in the 2018 ESOO released in August 2018.	Engie, p. 2	We have reflected the assumptions adopted by AEMO in its 2018 ESOO.
Generating and storage technology costs are undergoing a major review by AEMO and the CSIRO, with input from GHD, and are expected to be available early 2019.	Engie, p. 2.	While input assumptions are continually being reviewed by AEMO (and others), this is not a reason to delay the RIT-T. Moreover, there are found to be significant and robust net market benefits from energising a new interconnector to NSW as soon as practicable and so delaying its energisation would forego these benefits.
Cost and specification of options		
Viability of the non-interconnector option and interim solutions		
There is scope for a non-network solution to be applied over the short to medium term, ie, before the potential energisation date of the interconnector. Demand response represents a flexible operational and cost-effective solution for this transition period.	AGL, p. 1 & TEC, pp. 4-5.	Please refer to section 5.5 and the accompanying Entura report investigating the opportunity for interim non-interconnector support.
The purported costs of the non-interconnector option appeared to be overstated, and this option maybe the most economically efficient in the short to medium term.	The Energy Project, p. 2,[202] TEC, p. 2,[203] ECA, p. 3[204] & PIAC, p.1.[205]	See Appendix F for a discussion of the cost estimate of this option.
It is not clear how far ElectraNet have gone to test other options that may bring down the capital cost of the non-interconnector option. There are lower cost options that do not appear within the PADR such as an OCGT plant with a clutched synchronous compensation capability.	Origin Energy, p. 3.	Entura provided expert advice to ElectraNet on an optimised solution based on all the market information and offers received from proponents.

[202] This was also raised by The Energy Project at the Sydney deep dive session on 16 August 2018.

[203] References The Energy Project submission in making this point.

[204] References The Energy Project submission in making this point.

[205] References The Energy Project submission in making this point.

Summary of comment(s)	Submitter(s)	ElectraNet response
It is not clear why ElectraNet and Entura consider that the installation of minimum load control to enable the control of solar PV installations would be directly invested in by ElectraNet when the services could potentially be procured at relatively low cost either directly from consumers or via SAPN. This discussion appears also not to have considered how distributed battery storage could help to solve rather than create the problem.	TEC, p. 4	ElectraNet and Entura do not make any assumptions regarding who would make the investment in the installation of minimum load control to enable the control of solar PV installations. The RIT-T only looks at the costs of such options and not ownership or who makes such investment. ElectraNet would be a proponent of minimum load control of the non-interconnector if required. We agree that distributed battery storage could help meet the identified need. However, it is unlikely to do so without some mechanism that helps to direct it.
Do not agree with the conclusion that using batteries to inject power into the system, thus increasing supply, is likely to be more cost-effective than using demand response to reduce demand.	TEC, pp. 4-5.	ElectraNet received one proposal that included demand response. The proposal received was from an organisation well positioned to provide demand response, at a competitive cost. The indicative cost provided by the proponent exceeded the cost of installing a battery with the same nameplate rating (by a large margin) and offered performance, in terms of speed, inferior to the response of a battery. The offer also included considerable ongoing costs. Based on the lack of competitive proposals for demand response, the poor response speed of proposed demand response compared to the extensive proposals for batteries and good technical performance of the proposed batteries, it was concluded that demand response is not cost-effective compared to batteries.
Questions whether the least cost non-interconnector option in SA is directly comparable with the other interconnector options considered, given it does not meet the desired minimum system performance levels.	Australian Energy Council, p. 2.	ElectraNet agrees that the non-interconnector option does not provide the same level of system security as an interconnector option.
Load shedding should be considered as a solution to assist in managing the non-credible loss of an interconnector (in both the network and non-network option).	EnergyAustralia, p.4.	All credible options rely on load shedding (and Battery power injections) for non-credible contingencies.

Summary of comment(s)	Submitter(s)	ElectraNet response
The solution technical performance modelling completed by Entura does not appear to cover a realistic range of scenarios and most cases fail to consider inter-regional energy flow pricing impacts and the implications around local generation dispatch.	EnergyAustralia, pp.4-5.	Entura have drawn directly on AEMO OPDMS snapshots, selected to have approximately the desired South Australian load, interconnector flow and wind generation levels to create distinct study scenarios. The desired operating points were selected to define a technical envelope of likely power system operation including extremes of local inertia, extremes of interconnector flow and extremes of available wind generation. Extremes of the technical envelope may not match the most likely operating conditions in the market.

Summary of comment(s)	Submitter(s)	ElectraNet response
A significant advantage of the non-interconnector option is the flexibility of the shorter-term Network Support Agreement that would allow any market, policy or generation changes to be considered with a network option still possible in the future. We see that there is significant option value in the non-interconnector option that is not captured by ElectraNet. There is significant option value in the non-interconnector option that is not captured.	EnergyAustralia, p.5.	Material option value relies on four conditions – namely: • there is significant uncertainty about future conditions (e.g. potential for large mining load etc.); • there is expected to be 'learning' about that uncertainty in the future (e.g. large mining load occurs); • investment in the options needs to exhibit flexibility (in particular, there are different stages for the investment); and • there needs to be a possibility of regret (i.e. there is no 'obvious' best alternative under all future outcomes). These conditions are not substantively met for the most material driver of benefits of each option (including the non-interconnector option), which is the gas price. We do not consider there will be greater certainty regarding gas price forecasts in the coming years than exists currently. In addition, the low scenario in this PACR assumes a low long-term gas price of \$7.40/GJ (\$0.62/GJ lower than AEMO's ISP Slow Change scenario) and does not change the RIT-T outcome. Therefore, the RIT-T outcome is robust to future 'learning' regarding gas prices. Section 4.4 of this PACR outlines that a staged solution is not viable (ie, building a lower capacity option that is upgradeable to a higher capacity option if specific decision rules are met) or a lower capacity network solution coupled with a non-network solution. With respect to the materiality of option value generally to this assessment, as stated on page 47 of the PADR, "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."

Summary of comment(s)	Submitter(s)	ElectraNet response
A lower cost, more localised grid strengthening investment combined with strategic non-network solutions (eg, Option A) and greater incentives for demand response provide a lower risk pathway that does not lock consumers into paying for long-term investments that may not deliver benefits. More work is needed to consider these non-network opportunities if not to remove the need for the project but to reduce its scale so as to minimise costs for consumers.	EUAA, p. 4.	Since the commencement of this RIT-T assessment, the identified need has become more focussed on avoiding expensive gas generation in SA and less about security and reliability (which are largely being catered for outside of this RIT-T now). Such low cost solutions as mentioned by EUAA are not considered to be commercially feasible for this RIT-T, ie, they do not deliver net market benefits in the order of the credible options investigated.
Propose a Virtual Transmission Line complements the interconnector option.	Lyon Group, pp. 1-2.	We agree that it may complement an interconnector option. This new technology (as well as other new technologies) may further increase net market benefits with increased interconnection. Any such consideration will be undertaken through a separate RIT-T process.
Query whether additional gas fired generation investment, specifically additional fast start generators in either SA or NSW, should also have been included in the Entura analysis and what effect this would have on the economics of the preferred non-interconnector option.	Origin Energy, p. 2.	In the context of maintaining power system stability for an interconnector trip, supports are required to provide their support in less than 6 seconds and they are significantly more effective if this response can be provided in less than 1 second. In this context fast start generators are not fast enough to be useful.
Propose the use of modular power flow control, based on power electronics, in place of the more traditional use of phase shifting transformers and series compensation.	Smart Wires, pp. 2-4.	ElectraNet has reviewed the use of series compensation and has decided not to use series compensation due to its technical impact on potential generation connection. While Phase Shifting Transformers are mature technology and available to the scale proposed for the interconnection, the cost, scale and maturity of the proposed technology is not clear. However, ElectraNet and TransGrid are open to consider viable alternative technologies to provide power sharing between interconnectors at the design stage.
By still including the appropriate aspects of the non-interconnector option in the overall project, this could be expected to further bolster the economic outcomes from the RIT-T. Updates to the Murraylink controller, high-inertia synchronous condensers and similar developments listed in the non-network option would assist in connecting additional low-cost energy to SA for export to NSW.	Tilt Renewables, p.2.	Please refer to section 5.5 and the accompanying Entura report investigating the scope for interim non-network support.

Summary of comment(s)	Submitter(s)	ElectraNet response
The recent announcement of the opening of the SA Government's Home Battery Scheme suggests ElectraNet should include this in the analysis as a committed project.	The Energy Project (supplementary submission), p. 5.	Section 8.5 summarises how we have tested an expansion of Virtual Power Plants operation in South Australia (captured through a 450 MW controllable battery), in line with SA Government policy. This is far in excess of the Home Battery Scheme and it is found to not materially influence the overall net market benefits.
Queries whether a non-interconnector option needs to deliver the benefits of an entire interconnector in the option analysis.	EnergyAustralia[206]	An optimised non-interconnector option has been developed equivalent to the minimum need being addressed by an interconnector solution for direct comparison. Non-network components provide limited security benefits, recognising also that a new link has a broader transformational role in the energy market that a non-interconnector solution cannot fully deliver on its own.
Queries why solar thermal is included in the non-network option (it currently appears to have an uneconomically high cost).	Delta Electricity[207]	Entura provided expert advice to ElectraNet on an optimised solution based on all the market information and offers received from proponents.

[206] This was raised by EnergyAustralia at the Sydney Public Forum on 16 August 2018.

[207] This was raised by Delta Electricity at the Sydney deep dive session on 16 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
Queries how non-network solutions impact on the RoCoF constraint and special protection scheme.	The Energy Project[208]	The future special protection scheme is about protecting the system from the non-credible loss of either interconnectors, with two interconnectors in place. The RoCoF constraint is in place to ensure adequate levels of inertia to protect the system from the loss of the existing interconnector. The existing special protection scheme which also applies to the non-interconnector solution detects the impending separation of SA from the NEM and takes suitable action to reduce the risk. The scheme is not designed to manage the loss of interconnector (e.g. direct trip of the double circuit line). The non-interconnector solution reduces the risk of blackouts for trip of the double circuit lines of the existing interconnection. The assumed inertia values and interactions with the RoCoF constraint are discussed in the technical assumptions report.
Cost and specification used for the HVDC option		
An appropriate allowance for this option to enable more of the modern efficient Queensland coal-fired fleet to better achieve its technical life (rather that facing premature sidelining, mothballing or early closure) has not been included.	ARCMesh, p. 5.[209]	There is no outcome in either the RIT-T modelling or the ISP modelling that results in the early retirement of Queensland coal-fired generation. See Appendix G for a more detailed discussion.
The cost of the HVDC option is over-stated.	ARCMesh, p. 8.[210]	See Appendix G and accompanying Jacobs report, which independently reviews the cost of an HVDC option.
The PADR and the ISP have made almost zero recognition of the 'financial benefits' of the grid stabilisation benefits of using HVDC VSC interconnection technology to mesh the NEM grid.	ARCMesh, pp. 10-11.	See Appendix G for a detailed discussion of our consideration of HVDC VSC technologies.
A superior route for this option would be to head due west in SA parallel to the Qld-NSW border and, once the SA-Qld border is crossed, skirting around the Innamincka reserve and then heading south-west. The route largely follows existing gas pipelines and associated access tracks.	ARCMesh, p. 11.	See Appendix G for a discussion of the potential routing of the HVDC option, including potential to facilitate new renewable generation.

[208] This was raised by The Energy Project at the Sydney deep dive session on 16 August 2018.

[209] This was also raised by ARCMesh during the Adelaide Public Forum on 18 July 2018.

[210] This was also raised by ARCMesh at the Adelaide deep dive session on 17 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
There are unaccounted for benefits associated with this option from potential new generation developments along its route (eg, solar PV resources, undeveloped gas and geo-thermal resources).	ARCMesh, pp. 12-13.	
There would be considerable savings in transmission losses throughout the life of a new controllable HVDC interconnection spanning the NEM power system from Queensland to NSW. ElectraNet has underestimated this market benefit by using a DC power flow to estimate the sharing of power flows between NEM interconnectors.	ARCMesh, p. 13.	See Appendix G for a description of how transmission losses have been considered for HVDC options.
This option provides increased efficiency of generation dispatch due to the greater access to higher thermal efficiency super-critical coal-fired power stations in Queensland, compared with the less efficient NSW and Victorian coal fired power stations.	ARCMesh, p. 14.	See Appendix G for a detailed discussion of how this option is expected to affect these plants.
This option provides access to the higher cycle efficiency of Queensland's pumped storage schemes due to their large scale, high heads and short penstocks compared with the inefficient Snowy 2.0 scheme and the less efficient, smaller, low-head pumped storage schemes proposed elsewhere in NSW, SA and Victoria.	ARCMesh, p. 14.	See Appendix G for our consideration of how this option is expected to affect pumped storage in the NEM.
It should be feasible to deliver Option B, at least one year earlier than Option C, with lower risks of delays and cost over-runs.	ARCMesh, p. 16.	See Appendix G for a discussion of the expected construction lead times for an HVDC option.
This option is the only option to 'mesh' the NEM and is a solution to Australia's NEM interconnector design and the associated serious power system security and market aberrations. It is recommended that ElectraNet test Option B against Option C(i) for the incident that occurred in late August 2018 (ie, the tripping of QNI following a storm) and include the relative economic consequences in their economic comparison and recommendation.	ARCMesh, pp. 18-19 & 21.	See Appendix G for our consideration of how this option may improve the ability of the NEM transmission network to withstand specific high impact low probability ('HILP') events.
Alternative routing of SA to Victoria option and network hardening costs		
Modelling should be done in consultation with AEMO to clearly understand the benefits that flow from including 50 per cent series compensation between Robertstown and Buronga.	MEA Group, pp. 1-2.	ElectraNet has worked closely with AEMO throughout the course of this RIT-T, including in considering the benefits of series compensation. Since the PADR was released, we are no longer considering option variants that involve series compensation (ie, Option 3i and Option 4i in the PADR) as further technical assessment has identified alternatives that provide the same capability but avoid potentially restricting the connection of renewable generation to the series compensated line section.[211]

[211] Arising from the potential risk of sub-synchronous oscillations and consequential damage to generators and network equipment connected to the series compensated line section.

Summary of comment(s)	Submitter(s)	ElectraNet response
The cost of the assumed 300 MW OCGT plant in this option to mitigate the risk of bushfires is overstated and could be mitigated with lower cost, or different routed, solutions. The bushfire risk itself is also overstated.	AusNet Services, p. 2.	Section 4.3.3 outlines the assumptions regarding mitigating bushfire risk for this option.
It is advocated to assess this project in conjunction with the Western Victoria RIT-T (currently being undertaken by AEMO). Need to assess elements that are synergistic between SA and Victoria and could deliver greater benefits to customers than considering these projects in two separates RIT-Ts.	Engie, pp. 3-4 & The Energy Project[212]	The SAET PADR assumed no strengthening of the Victorian network in the base case. We were advised by AEMO on the appropriate scope and configuration of Option D. Option D1 and its variant, Option D1i, included some network augmentation that is also being considered by AEMO in the Western Vic RIT-T. There was potential for double counting the costs which may overstate the costs of the options in the SAET RIT-T (or vice versa). We therefore tested this assumption with a sensitivity on the costs of option D1 and D1i that reduced the cost assuming those overlapping components would be included in the preferred option for the Western Vic RIT-T. Reducing the costs did not make the Victorian option the preferred option, hence it did not affect the outcome of the SAET RIT-T. Since we published the PADR, AEMO has published the ISP and identified augmentation of the Victorian transmission network as a Group 1 project. Therefore, we amended Option D to assume the Western Victoria Renewable Integration RIT-T is included in the base case. For completeness, we also tested an alternative sensitivity that assumes the augmentations from the Western Victoria RIT-T do not go ahead. Overall, ElectraNet is working closely with AEMO on the Western Victoria RIT-T assessment to ensure mutually consistent assessments.
Alternative routing of SA to NSW options, including via Victoria		

[212] This was raised by The Energy Project at the Sydney deep dive session on 16 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
An alternate route should be considered that follows a route from Robertstown (SA) – Buronga (VIC) – Red Cliffs (VIC) – Kerang (VIC) – Darlington Point (NSW) – Wagga (NSW) as this option provides most (if not all) of the RiverLink benefits and incorporates ISP Group 1 and Group 3 projects.	AusNet Services, p. 4.	We have assessed an additional option variant to C.3 for interconnection between South Australia and NSW that deviates from Buronga to Kerang in and onwards to Darlington Point (new Option C.3ii).
The route outlined in the PADR could be enhanced by the addition of the Buronga to Red Cliffs upgrade included in the ISP.	AusNet Services, p. 5, MEA Group, p. 2 & South Australia Department for Energy and Mining, p. 46.	This has now been included in the preferred option. Appendix E summarises the AEMO assessment of the incremental net market benefits of this augmentation.
The NSW interconnector could be routed to Buronga and then divert via Red Cliffs and on through Horsham to connect with the Western Victoria Renewable Integration RIT-T development between Horsham and Melbourne.	AusNet Services, p. 6.	Section 4.3.3 outline how this alternate routing still exposes the transmission network to a substantial bushfire risk in what has been identified by CSIRO as a high bushfire area. The Western Victoria Renewable Integration RIT-T has also looked at a similar option with that PADR finding it is not preferred.
Smaller options should be considered as it is expected they can deliver most of the benefits at a greatly reduced risk to consumers.	Delta Electricity, p.2.	Section 5.7 outlines how smaller options are not considered to be technically feasible at any cost.
The route could be modified to go further north to track near potential mining developments, as well as current and future renewable developments.	Havilah Resources, pp. 2-6.	A detailed desk-top assessment has been undertaken to identify notional routes for each option. This has been with consideration to both potential renewable resources (as identified in the ISP) as well as potential mining developments. Whilst noting these submissions, our assessment is that in both cases the additional costs of these routes would not be outweighed by a corresponding increase in benefits within the electricity market. The RIT-T framework does not incorporate consideration of broader benefits to the wider economy. We have also engaged AME Advisory to do an independent analysis of the issues raised in response to the Curnamona Province, which has been released alongside this PACR. The preferred line route does not preclude the tapping into the lines to provide an efficient connection solution, as and when the need arises.
Consideration should be given to the broader State economic benefits that could result from the interconnector (and, in particular, an amended route to pick up north and/or north-east of South Australia prospective developments).	SACOME, pp. 9-10 & Havilah Resources, pp. 2-6.	

Summary of comment(s)	Submitter(s)	ElectraNet response
Encourage an examination of the reasons for why a SA-NSW interconnector has twice previously been found not economic and whether these reasons remain relevant in the current environment.	Origin Energy, p. 2.	These studies were done a number of years ago now and the energy market has changed drastically since (eg, closure of the Northern Power Station) and, consequently, so have the expected sources of market benefit from a SA-NSW interconnector.
Consideration should be given to whether the technical issues associated with the requirement for series compensation limit the potential for wind generation connection.	SmartWires[213]	The installation of series compensation, while increasing total transfer capability, is expected to increase the technical difficulty of connecting generation in its vicinity along the route of the interconnector, which has been taken into account in the assessment. The requirement for series compensation does involve some technical limitations (such as sub synchronous resonance and control interactions) which may impact on generation connection. In view of this, the final configuration removes the series compensation of the transmission line between Robertstown and Buronga, but provides the same level of transfer capacity as in the case of series compensation by other network augmentations and a redesign of the SPS.
Staging of options and coordination with other transmission developments		
It is possible that NSW and Victoria will have to strengthen their transmission systems along the proposed routes without this proposed interconnector as they cater for new generation at the extremities of their systems or improve supply for regional development in the case of Darlington Point.	CIT, p. 2.	We have worked closely with TransGrid and AEMO to make sure any such investments are captured in the assessment. Any such investments avoided through the interconnector's presence essentially add to the benefit of the interconnector (ie, these costs are avoided).
The cost of the SA to NSW options has been understated and should be increased by $30 million, plus the advancement cost of the subsequent $500 million Wagga-Yass 500 kV augmentation in NSW (total adjustment of $200 million NPV).	ARCMesh, pp. 8-9.[214]	See Appendix G for a direct response to this point and the separate Jacobs report for an independent review of the HVDC option's costs.

[213] This was raised by SmartWires at the Sydney Public Forum on 16 August 2018.

[214] This was also raised by ARCMesh at the Adelaide deep dive session on 17 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
Query whether further network investments are needed in NSW to unlock all potential benefits for consumers.	The Energy Project[215]	The benefits of the preferred option stand by themselves. TransGrid has provided detailed technical input to the option assessment. The benefits compound when further upgrades are added, as per the ISP. While the new interconnector would add around 800 MW of transfer capacity between the regions, it provides closer to 1,400 MW of additional connection capacity towards the deeper network in NSW. ElectraNet agrees that further benefits would be unlocked should deeper network augmentation take place.
Query whether network constraints have been taken into account between Wagga and Sydney.	EnergyAustralia[216]	Yes, additional benefits to those modelled would be available with a deeper network upgrade.
A more strategically timed approach to the NSW elements may better align costs and benefits for NSW consumers. ElectraNet and TransGrid are encouraged to explore options that include elements of Option A with staged investment in the NSW elements of the project.	The Energy Project, pp. 2 & 6.	See section 4.4 and Appendix F.
Opportunities should be investigated and validated to reduce the delivery timeframes as any project acceleration will bring forward benefits and the costs of such acceleration will likely be offset by the timing and quantum of these benefits.	South Australia Department for Energy and Mining, p. 46.	The South Australian Government has provided funding to allow preliminary works for the preferred option to be expedited, which may enable earlier energisation of this option than would otherwise be the case. Work is also underway to investigate the opportunity to further expedite delivery of the preferred option, subject to obtaining all required regulatory approvals.

[215] This was raised by The Energy Project at the Sydney Public Forum on 16 August 2018.

[216] This was raised by EnergyAustralia at the Sydney deep dive session on 16 August 2018.

<table>
<tr><th>Summary of comment(s)</th><th>Submitter(s)</th><th>ElectraNet response</th></tr>
<tr><td>Interested in knowing what early works are being proposed.</td><td>EnergyAustralia[217]</td><td rowspan="2">The Eyre Peninsula is an important region of South Australia and ElectraNet has recently finished a separate Eyre Peninsula Electricity Supply Options RIT-T assessing the most efficient transmission infrastructure for the Eyre Peninsula.[218]
In November 2018, ElectraNet requested a determination by the AER that the proposed investment satisfies the RIT-T, and upon receiving such a determination, we will seek AER approval of this investment as a contingent project.</td></tr>
<tr><td>Query whether this RIT-T includes any infrastructure development for the Eyre Peninsula.</td><td>Fresh Eyre, p. 1,
Ausker, p. 1.</td></tr>
<tr><td>Suggested an approach like Powering Sydney's Future could be taken where, after consumer feedback, TransGrid altered the scale of the project while also building in flexibility for a future upgrade and encouraged a similar approach here.</td><td>EUAA, p. 4.</td><td rowspan="2">Section 4.4 outlines why deferring the investment is expected to result in a net market cost. Table 6 summarises why we do not consider a staged development is feasible.</td></tr>
<tr><td>Need to examine opportunities for a deferred, staged implementation of the SA-NSW interconnector options.</td><td>PIAC, p. 2.</td></tr>
<tr><td>Only Option B aligns with a vision of an Australian grid exporting renewable energy to Indonesia.</td><td>ARCMesh, p. 23.</td><td>See Appendix G.</td></tr>
</table>

217 This was raised by EnergyAustralia at the Sydney deep dive session on 16 August 2018.

218 This separate RIT-T has found that the most efficient way to provide a reliable supply to the Eyre Peninsula is (1) a new double-circuit line from Cultana to Yadnarie that is initially energised at 132 kV, but which has the option to be energised at 275 kV if required in the future; and (2) a new 132 kV double-circuit line from Yadnarie to Port Lincoln. Additional detail on this project can be found on ElectraNet's website, ie: https://www.electranet.com.au/projects/eyre-peninsula-electricity-supply-options/

Summary of comment(s)	Submitter(s)	ElectraNet response
Specific comments on the RIT-T analysis framework		
Assessment period		
The preferred option is sensitive to the time period over which the NPV is calculated. Specifically, evaluating the project over 15 years yields other options with higher NPV than the PADR identified preference for Option C3i. The implication is that C3i only emerges as the preferred option if the analysis includes costs and benefits that appear in the model greater than 15 years into the future.	The Energy Project, p. 20, The Energy Project (supplementary submission), pp. 5-9, TEC, p. 2,[219] ECA, p. 3,[220] PIAC, pp. 1-2,[221] SACOSS, pp. 2-3.[222]	See section 4.5.1 and Appendix F.
There is a high degree of sensitivity around the time period chosen, including how the terminal value of the interconnector assets influences the final NPV outcome under the central scenario. We would like to see analysis of how the costs and benefits of a new interconnector stack up over periods of 10, 15 and 20 years post electrification, including a range of options for the treatment of terminal value.	Business SA, p. 1.	See section 4.5.1 and Appendix F.
Discount rate		
The ISP's real pre-tax 'WACC' of 6 per cent is reflective of the returns expected from low-risk, regulated assets and is too low for assets such as generators, which are exposed to market risk. It is suggested that a figure 200 to 300 basis points higher is more appropriate to be used for the analysis.	Australian Energy Council, p. 3.	See section 4.5.2 and Appendix F.
While ElectraNet's proposed 'WACC' covers fluctuations in the observed bond rate since the mid-1990s, it is materially lower than the preceding two decades. The high discount rates sensitivity should be substantially increased, unless some other form of protection is to apply (eg, a cap on the allowable regulatory return).	SEA Gas, p. 3.	See section 4.5.2 and Appendix F.

[219] References The Energy Project submission in making this point.

[220] References The Energy Project submission in making this point.

[221] References The Energy Project submission in making this point.

[222] References The Energy Project submission in making this point.

Summary of comment(s)	Submitter(s)	ElectraNet response
The NPV results appear to be sensitive to the discount rates and the choice of 6 per cent real as a 'commercial' discount rate is not reflective of the risk facing consumers, or the hurdle rate a business customer would apply to an energy investment, and should be revisited. Further, the supplementary submission made by The Energy Project states the lower bound of the 'regulated cost of capital' should be based not on current settings but at an estimate of the 'WACC' over the investment time horizon.	The Energy Project, p. 22 & The Energy Project (supplementary submission), p. 10.	See section 4.5.2 and Appendix F.
Cost estimates, cost recovery and the sharing of costs/risks between regions		
An investment framework that more efficiently allocates risks and costs is needed in order to advance the long-term interests of consumers.	The Energy Project, p. 5, SACOSS, p. 3, PIAC, p. 2 , EUAA, p. 1 & 5-7 & ECA, p.3.[223]	This sits outside of this RIT-T and we note that changes to the regulatory framework are currently being considered by governments and regulators.
ElectraNet, along with other stakeholders including the AER, should examine alternatives to the current model of funding any new interconnector, including: • models which may include government and/or generator co-contribution to reduce the risk of asset underutilisation borne by consumers; and • models which better balance the recovery of costs with the accrual of expected benefits between jurisdictions.	PIAC, p. 2.	
Request ElectraNet acknowledge the lack of a market mechanism to ensure future wind or solar developers/investors proportionately repay consumers who fund the interconnector and bear the asset redundancy risk.	Business SA, p. 2.	
It is clear that the project stacks up and the RIT-T process is costing consumers millions in delay given the net benefits involved. This is a shortcoming of the current framework.	Neoen[224]	
It is unclear how the matters detailed in the 2016 NTNDP regarding a review of market design have been taken into account.	SEA Gas, p. 3.	The market has changed significantly since 2016 and there are a number of market design reviews afoot considering these issues.

[223] References The Energy Project submission in making this point.

[224] This was raised by Neoen at the Sydney Public Forum on 16 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
There appears to be a disconnect between the benefits of the project, which flow mainly to consumers in SA, and the costs, which would be borne mainly by consumers in NSW.	The Energy Project, p. 2,[225] The Energy Project (supplementary submission), p. 10, TEC, p. 2,[226] PIAC[227] & Delta Electricity, p. 3.	The RIT-T is required to look at market benefits across the NEM as a whole to find the optimal solution, without looking at specific regional impacts. Most benefits in the short-term are derived from fuel cost savings in SA, while a longer-term benefit exists for options involving new interconnection with NSW through an increased ability to utilise generation in South Australia and to connect new renewable generation in NSW to avoid the higher costs associated with gas generation in NSW, as NSW black coal plant retires. Broader economy wide benefits, which may also accrue are beyond the scope of the assessment.
Interested in understanding the split of benefits between NSW and SA.	PIAC[228]	
Interested in understanding the benefits of the project to NSW consumers and whether there are any limitations in the ACIL modelling in relation to network development.	The Energy Project[229] & Business SA, p. 2.	ACIL Allen has modelled that the project produces a modest but consistent retail price reduction benefit to NSW, in proportion to the size of the interconnector relative to the size of the NSW system which exceeds the cost to NSW customers. The ACIL Allen modelling focuses on market development and price impacts but does not directly model the development of the network, so additional renewable development benefits are also possible that have not been fully captured. Overall the interconnector delivers the following benefits for NSW: • Unlocks renewable energy resources • Puts downward pressure on energy prices • Supports security and reliability in the face of early plant retirement risks

225 This was also raised by The Energy Project during the Adelaide Public Forum on 18 July 2018.

226 References The Energy Project submission in making this point.

227 References The Energy Project submission in making this point.

228 This was raised by PIAC at the Sydney Public Forum on 16 August 2018.

229 This was raised by The Energy Project at the Sydney deep dive session on 16 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
The Western Victoria Renewable Integration RIT-T costs should be excluded from Option D's costs since the solution has developed since the SAET RIT-T commenced and the ISP was published.	AusNet Services, pp. 3-4.	In the PADR we included the full costs of the augmentation as part of Option D, and took account of the interaction between the two RIT-T processes via inclusion of a sensitivity in relation to the Western Victoria RIT-T, which excluded the costs that are common with that separate investment. Following the publication of the PADR for the separate Western Victoria RIT-T, and the augmentation being identified by AEMO in the ISP as a Group 1 project for immediate progression, we have revised our approach in this RIT-T to exclude these costs from Option D. We have, however, considered the impact of this assumption via a sensitivity which continues to incorporate all of these costs as part of Option D (which is presented in section 8.5.2).
There is scope for cost overrun once challenges like receiving environmental approvals and obtaining new easements are factored in. An independent assessment of the potential for material cost overruns should be performed.	Delta Electricity, p.2.	ElectraNet considers the cost estimates developed for the RIT-T are appropriate for this stage of the project. In addition, Section 8.5 shows that identification of the preferred option is insensitive to the cost sensitivities investigated. A high-level breakdown of the cost estimates of the options considered is included in Appendix I. Also an expanded Cost Estimate Report is published alongside this PACR.
Greater clarity should be provided on the costing assumptions for the interconnectors. If ElectraNet's analysis has not already done so, some of the complexities of constructing large transmission projects should be accounted for, to ensure that market participants have as accurate a view of the costs as possible, eg: • An allowance for contingency capex • Whether there are any native title issues. • Development approval costs. • Any required augmentations to the existing shared network to facilitate interconnection.	Origin Energy, p. 2.	
No details have been provided on the life-cycle operation and maintenance costs for either Option B or Option C(i), other than an additional allowance appears to have been included in Option B. The operation and maintenance costs of Option B's HVDC transmission lines and primary equipment are expected to be lower than the equivalent operation and maintenance costs for Option C(i), as there are only approximately half the number of conductors and insulators and much less HVAC substation equipment.	ARCMesh, p. 20.	HVDC VSC converters have more maintenance and the valves and controls need to be replaced in 20 to 30 years. Compared to this, the HVAC options have a design life of 45 to 55 years, with minimum maintenance. More fundamentally, the assumed O&M costs differences between the preferred option and the HVDC option are immaterial to the selection of the preferred option, given the more substantive relative differences in capital costs and the expected market benefits between options.

Summary of comment(s)	Submitter(s)	ElectraNet response
The cost used in the RIT-T should be in the RAB to prevent cost over-runs and have ElectraNet share some of the risk.	Delta Electricity, p.3.	There is a well-defined regulatory framework in the NER for how the costs of a project like this are included in ElectraNet's RAB (and the implications of any cost overruns).
Unless Australian shortages of skilled construction workers and specialised construction equipment are urgently addressed, the construction costs and construction times for Option C (i) are unlikely to be achieved.	ARCMesh, p. 17.	We consider that all options can be delivered in the timeframes proposed in section 5. Moreover, any impact of skills shortages should not be expected to materially affect one option over another.
Why has ElectraNet not included private developers of an interconnector solution in the RIT-T process.	ARCMesh[230]	Early in the consultation process, as part of the PSCR, ElectraNet received submissions from private enterprises, including a submission from the owners of Murraylink. That submission presented information and ideas for a new interconnector between SA and Victoria and, as a result, ElectraNet has included and modelled that option in the PADR. ElectraNet has also considered an interconnector option between SA and Queensland, which has been informed by ARCMesh's submissions and subsequent discussions. ElectraNet has taken into account all the information received during the consultation process in developing credible options for this RIT T.
Assessment criteria for identifying the preferred option		
NPV does not consider the quantum of capital required to complete a project and there are other measures, such as the cost-benefit ratio, or profitability index, which serve better as an indicator of how efficiently the capital would be employed.	Australian Energy Council, p. 3 & EnergyAustralia, p.6.	The RIT-T requires the use of net market benefits as the assessment criteria.
Further consideration should be given to the additional benefits generated by the proposed Buronga Energy Station project and other similar projects, eg, adding generation capacity, potentially increasing the interconnector capability and promoting regional employment and investment.	Renew Estate, p. 2.	The market benefits of connecting any renewable energy are picked up in accordance with the RIT-T and ISP. Wider benefits, such as regional employment and investment, are not permitted under the RIT-T.

230 Raised during the Adelaide Public Forum on 18 July 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
Time parties had to review information released		
Given the short timeframes available, SEA Gas has not reviewed the additional materials published by ElectraNet on 22 August 2018 in relation to its public consultation on the PADR.	SEA Gas, p. 1.	The consultation process adopted for this RIT-T has needed to provide an appropriate balance between providing information to stakeholders and explaining that information in order to enable their active participation in the process, as well as ensuring that the assessment is completed in a timely fashion. There has been a large amount of information released as part of this RIT-T and, in recognition of this, ElectraNet twice extended the time parties had to prepare a submission.[231] Section 2 of this PACR outlines the extensive consultation undertaken as part of this RIT-T.
The limited time available to respond to the ElectraNet PADR has prevented ARCMesh from undertaking further analysis and quantification of a number of other, substantial considerations that strongly support the development of Option B over Option C(i).	ARCMesh, pp. 1 & 17.	
Stakeholders were provided only eight days to interrogate and analyse the published data, draft a report, get feedback from signatories and finalise a submission to this process.	The Energy Project (supplementary submission), p. 2.	
Due to the constraints of time in preparing this PADR submission, we present a preliminary estimate of costs and benefits.	South Australia Department for Energy and Mining, p. 46.	
Other points raised in submissions		
Impact on electricity prices		
Hesitant to see large capital expenditure without a guaranteed lowering of retail prices on offer to customers.	CIT, p. 2.	Independent modelling by ACIL Allen estimates an overall reduction in the average annual residential customer bill of about $66 in South Australia and $30 in New South Wales, and an annual reduction for small business customers of around $132 in South Australia and $71 in New South Wales.
Concerned that the interconnector could result in increased renewable energy prices for SA users due to the creation of an export market in NSW (suggesting that something similar to what occurred in the gas market might happen when the Gladstone terminal was opened in October 2015, exposing domestic users to export pricing levels).	SACOME, p. 9.	

231 Specifically, on 11 July 2018, at the time of releasing the Market Modelling and Assumptions Report and the ACIL Allen report on the potential price impact, we extended the submissions period by two weeks. On 17 August 2018, we further extended the deadline by another week due to the fact that we were to provide new additional material at stakeholder request on 22 August 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
Substantial reduction in pool price volatility in the NEM, particularly in South Australia and Queensland.	ARCMesh, pp. 20-22.	All interconnector options deliver this outcome. The HVDC options do not do this any more or less than the alternative options. In addition, a reduction in prices or volatility is not a benefit in itself that can be considered by the RIT-T. Rather, it is only the subsequent impact of such a reduction on consumption and investment decisions that affect RIT-T outcomes.
Interaction with telecommunications infrastructure		
Interested in understanding the communications link the proposed interconnector will come with and whether those assets may be shared with generators and/or consumers within the Murray/Riverlink region.	Maoneng, p. 1.	It is assumed at this point that the interconnector will have the standard required communication links (OPGW) but this will all be worked through in due course.
Option B would only require a minor additional investment to connect to the existing high capacity telecommunications systems in the Port Augusta area as well as substantially enhancing existing telecommunications services in those remote parts of inland Australia. The additional income could generate a substantial net benefit and revenue source that is allowable under the RIT-T that has not been factored into the assessment.	ARCMesh, pp. 19-20.	All interconnector options are assumed to have standard communications equipment (OPGW). The benefit suggested by ARCMesh is not expected to differ materially across options and certainly not to the extent to change the identified preferred option.
Capacity of the interconnector options		
Query why, if both interconnectors are limited to 650 MW, the size of the proposed new interconnector at 800 MW.	Delta Electricity[232]	Many factors were considered when setting the default capacity of the new interconnector solutions. However, the proposed new interconnector would not be limited to operating at this default capacity and could allow higher power flows. The proposed new interconnector would be fitted with phase-shifting transformers which allow power flows to be controlled. Depending on the operating conditions, limits on this new interconnector could be increased provided the combined capacity limit of the Heywood Interconnector and the new interconnector is maintained.

[232] This was raised by Delta Electricity during the Adelaide Public Forum on 18 July 2018.

Summary of comment(s)	Submitter(s)	ElectraNet response
Interested to know what the combined increase in transfer capacity is with a new interconnector.	Andrew Campbell[233]	The SA-NSW interconnector is scoped at 800 MW capacity with a combined import transfer capacity limit of 1,300 MW to SA (excluding Murraylink). This combined transfer limit is being modelled conservatively, and any additional effective transfer capacity would unlock greater benefits. ElectraNet has published an updated Market Modelling Report with this PACR, which lists notional interconnector capabilities under each of the interconnector routes, over both the short- and long-term.
Interested in understanding what capacity that was assumed for the Queensland interconnector option.	ARCMesh[234]	A capacity of 700 MW under summer conditions was modelled with a combined import transfer capacity limit of 1,300 MW to SA, equivalent to other interconnector options. In addition for Option B we have assumed an improved transfer limit of 250 MW across QNI. Additional detail is provided on these transfer limits in the separate PACR Market Modelling Report.

233 This was raised by Marsden Jacobs at the Adelaide deep dive session on 17 August 2018.

234 This was raised by ARCMesh at the Adelaide deep dive session on 17 August 2018.

Appendix D Market benefit categories considered

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.[235]

Our assessment conducted for the PADR 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. None of the submissions received on the PADR suggested that these categories of market benefits should be considered. We therefore continue to conclude that these categories of market benefit are not material for this RIT-T.

The table below summarises why we have either included or excluded each category of market benefit stipulated under the NER.

Table 12 – Consideration of market benefit categories under the RIT-T

Market benefits	Included in this RIT-T?	Reason for including or excluding from this RIT-T
Changes in fuel consumption arising through different patterns of generation dispatch	✓	The options considered augment the power transfer capability between regions directly. This enables efficient sharing of generation resources, both existing and new, between regions, allowing lower cost generation to displace higher cost generation and, overall, reduce the aggregate fuel costs in the NEM. This is a key expected category of market benefit for all options considered due to need for expensive gas generation to operate in South Australia if no option is pursued, as well as the high quality of new renewable generation able to be built in South Australia. In addition, as outlined in section 3.3 above, the options considered 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. This impact is reflected in the RIT-T as a component of the fuel cost savings in South Australia, as alleviating the constraints reduces the requirement for dispatch of higher cost gas generators in South Australia.
Changes in 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. As set out in section 8 above, these benefits are relatively minor for this RIT-T.

[235] 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.

Market benefits	Included in this RIT-T?	Reason for including or excluding from this RIT-T
Changes in 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. As set out in section 8 above, these benefits are relatively minor for this RIT-T. We have adopted AEMO's standard assumptions for VCR for the purposes of this assessment.
Changes in costs for parties, other than the RIT-T proponent, due to: (A) differences in the timing of new plant; (B) differences in capital costs; and (C) differences in the operating and maintenance costs.	✓	The options encourage more efficient investment in lower cost generation sources than would be built without these investments. An enhanced ability to export low cost power from South Australia, including significant high-quality renewables, provides 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 between South Australia and New South Wales, due to the retirement of coal plant forecast, and which otherwise would rely on higher cost sources of generation to fill the resulting supply gap. The market benefits are derived from avoided generator fixed operating costs and new generator and storage capital cost deferral (or avoidance).
Differences in the timing of expenditure	✓	New interconnection has the potential to substitute for the additional intra-regional transmission investment that would otherwise be required to unlock REZs to enable NEM transition. This provides a market benefit through the avoidance or deferral of unrelated transmission investment. In addition, the interconnector options allow for other minor transmission expenditure to be deferred, further adding to this benefit.
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 and changes to voluntary and involuntary load shedding.

Market benefits	Included in this RIT-T?	Reason for including or excluding from this RIT-T
Changes in ancillary services costs	X	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	X	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	X	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.
Other classes of market benefit	X	NA

Appendix E Benefits of the 220 kV Buronga-Red Cliffs upgrade

Summary points:

- AEMO have undertaken an investigation of the incremental benefits of including the Buronga - Red Cliffs 220 kV line component as part of the South Australia – NSW interconnector options.
- AEMO's modelling demonstrates that this is expected to provide additional net benefits that outweigh the additional cost of the investment required. The benefits presented in main body of this report do not include the market benefits presented in this Appendix.
- The modelling in this PACR has therefore explicitly incorporated a Buronga - Red Cliffs 220 kV augmentation in estimating the costs and benefits of all of the South Australia – NSW interconnector options (specifically options C.3, C.3ii and C.3iii).
- This appendix summarises the assessment of the incremental benefit undertaken by AEMO.

This appendix presents AEMO's analysis of the incremental benefits that are expected to be provided through the inclusion of the Buronga - Red Cliffs 220 kV line component as part of the South Australia – NSW interconnector options.[236] This analysis has led to the inclusion of Options 2 and 5 being the double circuit line (option 2) and the associated transformers (option 5) being included in the preferred option of this PACR. Details on the credible options for this upgrade are also included in this appendix.

The analysis has been prepared by AEMO in the course of investigations for its concurrent Western Victoria RIT-T, following close consultation with ElectraNet and TransGrid. AEMO's modelling demonstrates that the addition of 500 MW of generator connection capacity at Red Cliffs is expected to provide additional net benefits that outweigh the additional cost of the investment required to achieve this. These benefits arise from enabling the development of solar generation in the Murray River REZ, which can be exported to South Australia and NSW through the new SA-NSW interconnector.

As discussed in the main body of this report, the modelling in this PACR has explicitly incorporated a Buronga - Red Cliffs 220 kV upgrade in estimating the costs and benefits of all of the South Australia – NSW interconnector options (specifically options C.3, C.3ii and C.3iii). The benefits presented in the main body of the PACR do not include the benefits of the Buronga to Red Cliffs line component in this appendix. This appendix demonstrates that the incremental benefits of Buronga to Red Cliffs are a net market benefit positive addition to the preferred option.

Although AEMO's assessment is based around its own neutral, slow change, fast change and neutral with storage scenarios, the substantive overlap between these scenarios and the scenarios that have been adopted in the SAET PACR means that the results can be taken as reflecting the results that would be obtained if this analysis was re-run using the SAET scenarios.

[236] The methodology underpinning AEMO's assessment is presented in more detail in AEMO's PADR in relation to the Western Victoria RIT-T, see: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2018/Western-Victoria-Renewable-Integration-RIT-T-PADR.PDF

We therefore do not consider that re-running this assessment would materially alter the core result, which is that adding the Buronga - Red Cliffs 220 kV component to the South Australia-NSW interconnector options results in a material incremental net benefit.

Following this assessment by AEMO, we have modelled the Buronga - Red Cliffs augmentation in this PACR as increasing the capacity to connect generation to the Victorian Murray River REZ by 400 MW. This appendix summarises the incremental benefit assessment undertaken by AEMO. AEMO's modelling has been provided as a further attachment to this PACR.

E.1 AEMO's assessment

AEMO has modelled an additional 500 MW of generator connection capacity at Red Cliffs achieved via a new 220 kV transmission line between Red Cliffs and Buronga, in parallel to the existing Red Cliffs to Buronga line, together with a second 400 MVA 330/220 kV transformer at Buronga. The modelling assumes that a new South Australia – NSW interconnector is in place[237] and that the preferred augmentation identified in the PADR for the concurrent Western Victoria RIT-T also proceeds. The results show that a Red Cliffs - Buronga upgrade will increase the value of a Western Victoria augmentation, and provide a further incremental increase in net benefits overall.

The augmentation of the Red Cliffs - Buronga 220 kV transmission line has very high gross market benefits after the South Australia – NSW interconnector is energised, because it enables the development of solar generation around Red Cliffs Terminal Station, in the Murray River REZ. Thermal limitations in the 220 kV transmission network around the Murray River REZ can limit solar generation flowing into the Victorian load centre, however this generation can be exported to South Australia and New South Wales through the South Australia – NSW interconnector.

The Murray River REZ is also the only Victorian REZ with high quality solar resources and can provide generation diversity to the wind generation that is being developed in Victoria.

AEMO's analysis for the Western Victoria RIT-T found that allowing generation expansion in both the Western Victoria REZ and Murray River REZ will result in more solar generation, but less overall new generation (i.e. total MW capacity of wind generation, solar generation, gas generation and pumped hydro generation) in Victoria.

The following figures provide a breakdown of the estimated generator capital savings benefits, fuel savings benefits, cumulative gross benefits and cumulative annualised costs. The results of the modelling underlying this assessment has been provided as a further attachment to this PACR.[238]

---

[237] Specifically, a new 330 kV HVAC line from Robertstown SA to Wagga Wagga in NSW, via Buronga (ie, Option C.3i in the SAET PADR RIT-T assessment).

[238] Incremental NPV benefits of Red Cliffs to Buronga Line, AEMO

Figure 1 Red Cliffs to Buronga 220 kV upgrade: gross benefits and investment costs in the Neutral scenario

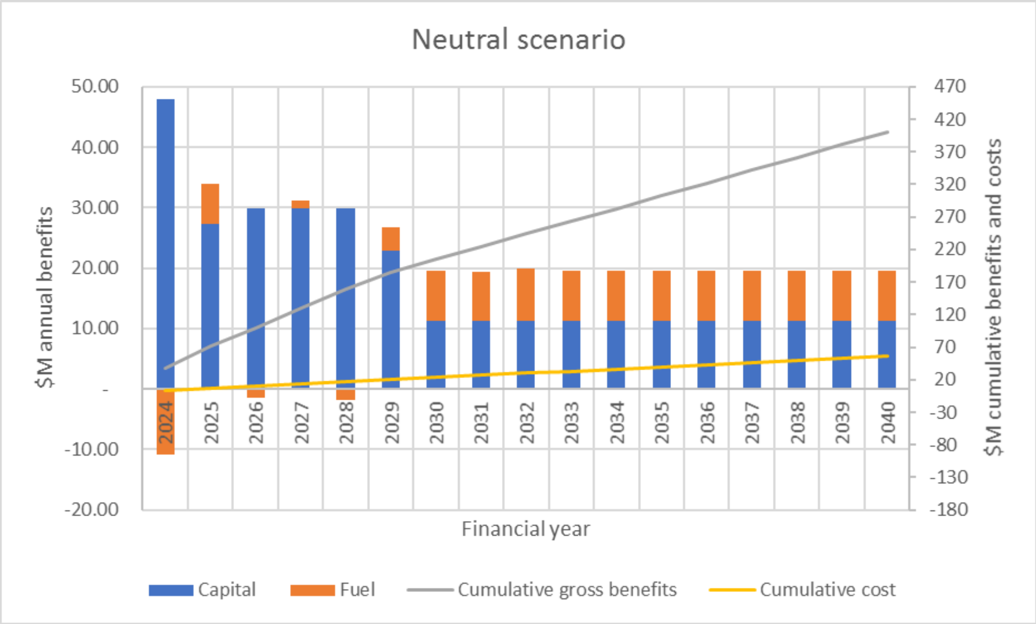


Figure 2 Red Cliffs to Buronga 220 kV upgrade: gross benefits and investment costs in the Neutral with storage scenario

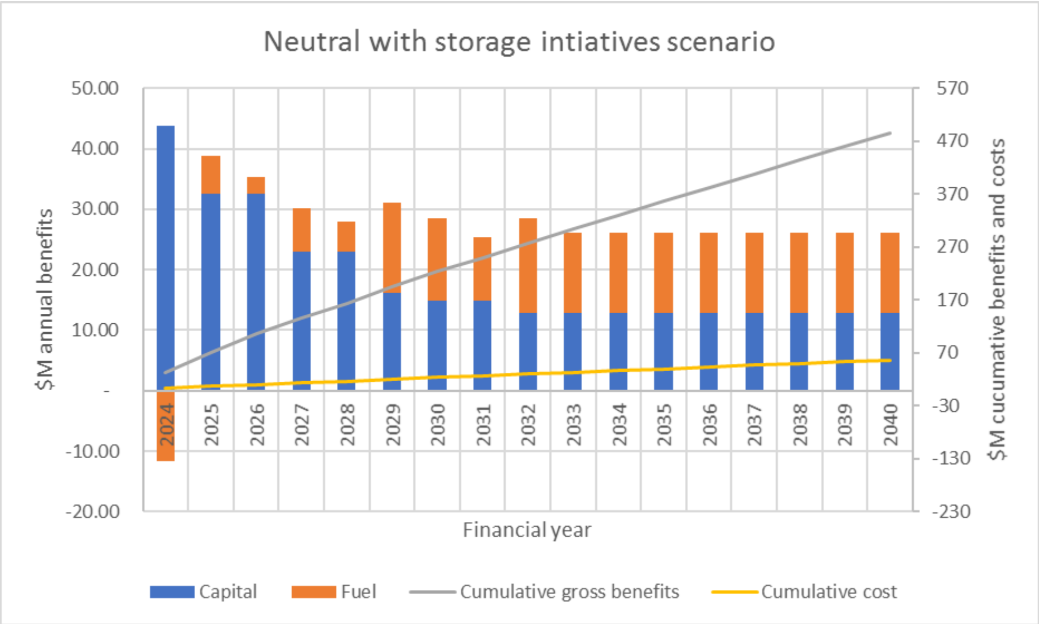
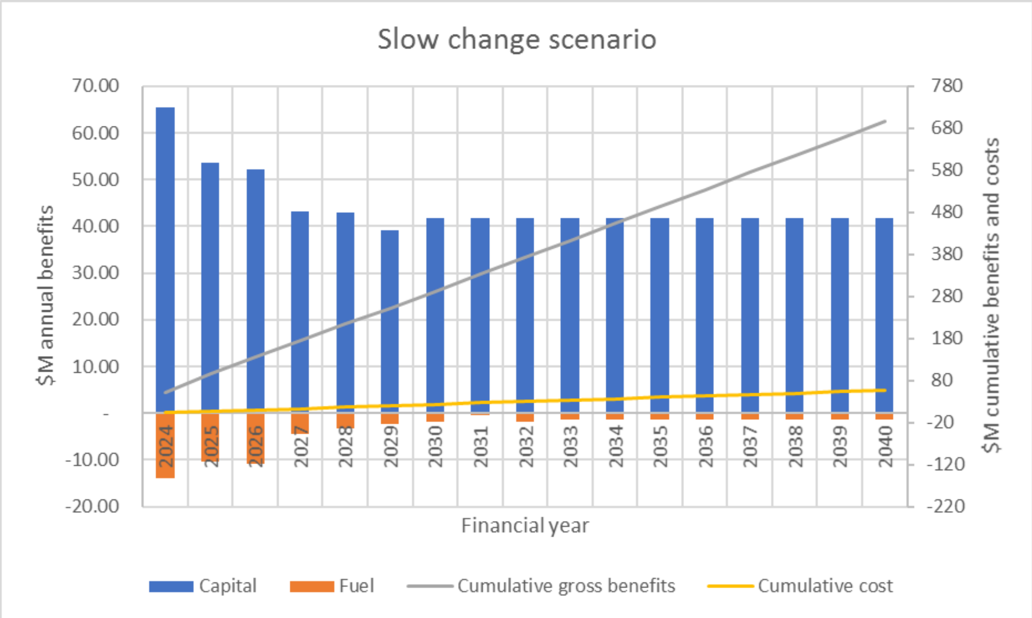
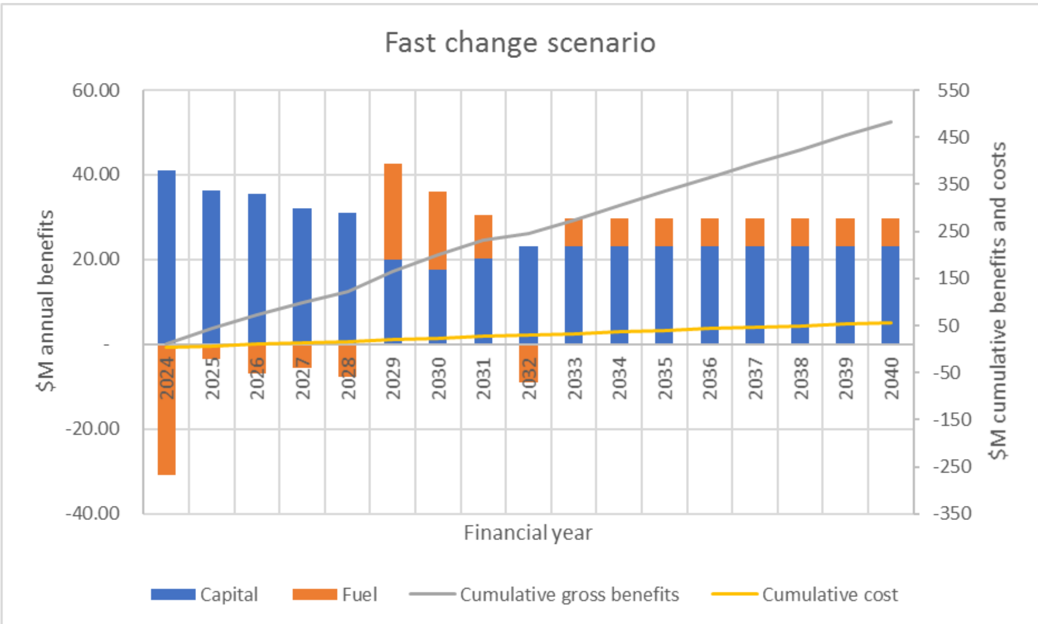


Figure 3 Red Cliffs to Buronga 220 kV upgrade: gross benefits and investment costs in the Slow Change scenario



The Red Cliffs to Buronga upgrade will provide net market benefits immediately after the interconnector is energised, and its optimal timing should therefore be the same as the interconnector.239

Figure 4 Red Cliffs - Buronga 220 kV upgrade: gross market benefits and investment costs in the Fast Change scenario



239 The modelling for this PACR has been based on a 1 July 2023 energisation date for the South Australia – NSW interconnector.

E.2 Buronga to Red Cliffs upgrade – option details

The below table provides details on the credible options considered by AEMO for the Buronga to Red Cliffs augmentation.

Table 13 – Options considered by AEMO for the Buronga to Red Cliffs augmentation

Item	Description	Cost ($m 2018/19)	Details
1	New single circuit from Red Cliffs to Buronga	$28.4	Comprising - Twin lemon conductor. - One side incl. 48 fibre OPGW. - ~ 24kms in length. - BUR 1 x 220 kV single CB line bay. - RCTS 2 x 220 kV single CB line bays
2	New double circuit from Red Cliffs to Buronga, string one side initially	$34.4	Comprising - Twin lemon conductor. - One side incl. 48 fibre OPGW. - ~ 24kms in length. - 2nd side of double circuit will contain no line assemblies - BUR 1 x 220 kV single CB line bay. - RCTS 2 x 220 kV single CB line bays High level analysis shows Option 2 will have additional option value benefits compared to Option 1, by allowing for future expansion.
2b	String second side of double circuit line above at a later stage.	$7.2	
3	Rebuild existing single circuit Red Cliffs to Buronga line as new double circuit.	N/A – See option details.	High level analysis shows that the unit cost of dismantling the 220 kV line is higher than the cost of securing new easements. Therefore, Option 3 is eliminated because it is likely to cost more and have lower net market benefits compared to Options 1 and 2.
4	Upgrade 220/330 kV transformer at Buronga to at least 800 MVA	N/A – See option details.	High level analysis shows that in the 6 year period between 2013 and 2018, an outage of the Murraylink interconnector resulted in an average marginal market impact of $6.4m per annum. Therefore, Option 4 is eliminated because a single transformer outage will result in disconnection of Victoria from the new SA-NSW interconnector and south west NSW, and will likely result in a large market impact.
5	2 x 220/330 kV transformers at Buronga	$11.4	Comprising - Single CB 330 kV and single CB 220 kV switch bays. - 1 x 330/220 kV 400 MVA transformer

Generation expansion modelling carried out for the ISP for various scenarios shows that additional solar generation development in Victoria will be required by around 2035, or earlier if some coal generation retirements are brought forward.

Implementing the Red Cliffs - Buronga augmentation as a double circuit single strung 220 kV line (which has an incremental cost of $6 million) will provide additional net market benefits of approximately $3 million[240] over a single circuit 220 kV line by allowing future expansion and is therefore considered as the preferred option for this upgrade.

The cost of Red Cliffs - Buronga augmentation is combination of Option 2 (new double circuit from Red Cliffs to Buronga, string one side initially ($34.4 million)) and Option 5 (2 x 220/330 kV transformers at Buronga ($11.4 million)), with a total cost of approximately $46 million.

[240] In NPV terms, over the study period.

Appendix F Detailed response to points raised by The Energy Project

Summary points:

- It is important that the economic assessment period is sufficiently long to capture any material differences between options in relation to future benefits, with uncertainty relating to future outcomes being reflected through scenarios and sensitivity analysis rather than truncating the assessment period.
- The inclusion of terminal values is consistent with the AER RIT-T Guidelines and cost benefit analysis more generally and allows comparison between options with differing asset lives and different opex and capex profiles.
- Adoption of a shorter 15 year assessment period continues to find Option C.3 to be the preferred option, once terminal values are properly accounted for.
- Sensitivity analysis using 30 per cent lower costs for the non-interconnector option also continues to find Option C.3 to be preferred.
- In part this is because the non-interconnector option only contributes to enhancing system security and does not meet all the requirements of the identified need for this RIT-T.
- Option C.3 has an estimated payback period of nine years under the central scenario.
- Staging of investment between South Australia and New South Wales would not result in the associated market benefits being realised, as the whole option is required in order to deliver both the near-term and medium-term benefits.

This appendix provides a further, more detailed response to points raised by The Energy Project, through its initial and supplementary submissions to the PADR as well as through participation in the stakeholder sessions held as part of our consultation.

The Energy Project submission was funded by Energy Consumers Australia (ECA) and was referenced in a number of other submissions (ECA, PIAC, SACOSS and the Total Environment Centre).

The Energy Project and the ECA summarised the issues raised in the submission as:

- timing risk;
- risk of over-estimation of the costs of the non-interconnector (Option A); and
- allocation of risks and costs between regions.

On the basis of its analysis, The Energy Project recommended that ElectraNet and TransGrid explore staged options for investment that better align costs and benefits for NSW customers, and included elements of the non-interconnector option.

We address each of these issues in turn below.

The Energy Project supplementary submission also made a number of observations in relation to their experience as a stakeholder engaging with us during this RIT-T process. We address the topic of stakeholder engagement and information provision during this RIT-T in the main body of this report (section 2).

F.1 Timing risk and assessment period adopted

The Energy Project raises a number of points in relation to the assessment period selected for the RIT-T assessment and, in particular, has provided analysis that it considers shows that adoption of a shorter 15-year assessment period would alter the identification of the preferred option.

In its original submission, The Energy Project identified Option A (the non-interconnector option) as the preferred option if a 15-year assessment period was adopted.[241] In a supplementary submission, The Energy Project noted that they had made some errors in interpreting spreadsheets provided by ElectraNet in undertaking this analysis, and that the supplementary submission reflects a better understanding of the operation of the spreadsheets.[242] The Energy Project also noted that its original submission did not make an allowance for terminal values in the same way as ElectraNet's analysis does. [243]

In its supplementary submission, The Energy Project characterises its key point in relation to 'timing risk' as being that the PADR relies heavily on outcomes that are a long way into the future and come with uncertainty and hence risk for consumers.[244]

The Energy Project considers that this conclusion still holds, after updating its analysis to reflect its revised understanding of the spreadsheets provided by ElectraNet. The supplementary submission illustrates this point by undertaking a number of alternative approaches to evaluating the project over 15 years, involving (i) excluding terminal values; (ii) including terminal values; (iii) depreciation over 15 years; and (iv) assuming 30 per cent lower costs for Option A (non-interconnector option) plus depreciating over 15 years.

Below we consider each of the approaches adopted by The Energy Project in turn. In brief, we consider that only the second approach (including terminal values[245]) represents an appropriate approach to the identification of the preferred option.

However, the two approaches used by The Energy Project that reflect rapid depreciation (ie, referred to as 'Rapid Depreciation', and 'Rapid Depreciation for Option A'[246]) provide useful metrics to inform the degree of risk associated with the adoption of the preferred option, and we have therefore reflected these metrics in the PACR analysis.

[241] TEP submission, 31 August, p.20.

[242] TEP supplementary submission, 6 November, p. 2, p. 4.

[243] TEP supplementary submission, 6 November, p. 4.

[244] TEP supplementary submission, 6 November, p. 10.

[245] TEP supplementary submission, 6 November, section 4.2.

[246] TEP supplementary submission, 6 November, section 4.3 and section 4.4.

Adoption of a shorter assessment period

A central part of the analysis presented in The Energy Project's supplementary submission (consistent with the original submission) remains that Option C3i 'does not emerge as the option with the highest net market benefit when considered over a shorter time horizon' (emphasis added).[247] All of the assessments presented in the supplementary submission are based on a 15 year time frame, which The Energy Project characterises as reflecting 'the medium term'.[248]

The NER and the AER's RIT-T Application Guidelines are not prescriptive regarding the choice of assessment period, saying only that 'the duration of modelling periods should take into account the size, complexity and expected life of the relevant credible option to provide a reasonable indication of the market benefits and costs of the credible option'. However, the AER Guidelines do state that:[249]

> 'in the case of very long-lived and high-cost investments, it may be necessary to adopt a modelling period of 20 years or more'

Other RIT-T assessments of interconnectors and other major transmission augmentations (ie, 'long-lived and high-cost investments') in Australia have adopted assessment periods ranging from 20 to 50 years.[250] This includes RIT-Ts completed within the last year, as well as earlier RIT-Ts where the extent of uncertainty in relation to future energy sector policies, generator retirements and future demand outlook was arguably as uncertain as it remains today.

Assessment periods of this length, or longer, are also applied in other jurisdictions. For example, the European Network of Transmission System Operators for Electricity (ENTSO-E) 'guideline for cost benefit analysis of grid development projects' published on 27 September 2018 states that "[t]he analysis period starts with the commissioning date of the project and extends to a time-frame covering the economic life of the assets".[251]

In PJM[252] in the United States, the economic assessment has an assessment period of 15 years from the energisation date of the asset (ie, following the completion of construction) for the purposes of setting the revenue requirement for the same period.[253]

---

247 TEP supplementary submission, 6 November, p. 4.

248 TEP submission, 31 August, p. 5.

249 AER, *RIT-T Application Guidelines*, September 2017, p. 39. This was also reiterated in the recently updated AER Guidelines, see: AER, *RIT-T Application Guidelines*, December 2018, p. 63.

250 The 2014 TransGrid and Powerlink QNI RIT-T adopted a 50-year assessment period, whilst the RIT-T conducted by AEMO and ElectraNet for the Heywood interconnector upgrade adopted a 41-year period. More recently, the TransGrid and Ausgrid Powering Sydney's Future RIT-T and the recently completed ElectraNet Eyre Peninsula RIT-T both adopted a 20-year assessment period.

251 ENTSO-E, *2nd ENTSO-E Guideline For Cost Benefit Analysis of Grid Development Projects*, 27 September 2018, p. 24.

252 PJM Interconnection is a regional transmission organisation in the United States that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

253 The PJM's CBA methodology is set out in their Region Transmission Planning Process Manual (at page 48 and Attachment E). A presentation outlining the assessment framework with some simple worked examples is available here.

The 21-year assessment period to 2040 adopted in the PADR includes the time taken to plan, procure and construct the options. For the preferred option there are therefore only 17 years of modelled market benefits, for an asset which is expected to have a life of over 40 years. Given this long asset life, the 15 year assessment period adopted by TEP (which only incorporates 11 years of benefits), may be more appropriately characterised as reflecting a 'short-term', rather than a 'medium term' view.

In response to The Energy Project's original submission, we sought advice from HoustonKemp Economists on the appropriate assessment period for the investments being considered in this RIT-T, which we subsequently discussed with The Energy Project and published on our website.[254]

HoustonKemp highlights that the guiding principle for determining the relevant assessment period should be that it is sufficiently long so that it captures the key differences in the costs and market benefits across the credible options assessed. That is, the assessment period should be the point at which identification of the preferred option stabilises, and assuming a longer period would not change the identified preferred option, as beyond this point the relativity of the costs and benefits between options is not expected to change materially.

This implies that the assessment period should extend out past the point that any material changes in the costs or benefits associated with one option compared to another are expected to occur (and the network is therefore in a 'similar state'). Where there is a marked change in the future benefits projected (such as the 'modelled inflection in benefits at 2033' referred to by The Energy Project in the context of the PADR results[255]), it is therefore important that the assessment period is sufficient to reflect the impact of this inflexion on the relative benefits of different options, rather than being truncated to exclude this inflection.

This concept is consistent with The Energy Project's objective of exploring the robustness of the findings to the assessment period adopted. However, The Energy Project's assessment only considers the robustness of the analysis to *shorter* assessment periods. We consider that it is also important to consider how the results stabilise as the assessment period is increased to capture benefits over more of the asset's life.

The economic modelling undertaken for the SAET PADR found differences in the drivers of the benefits accruing between options, particularly in the medium to long-term.

In particular, in the context of the projected retirement of NSW coal plant in the 2030s, the SA-NSW interconnector options enable NSW demand to be met through an increased ability to utilise generation in South Australia and to connect new renewable generation in NSW (avoiding the higher costs associated with gas generation in NSW).

These benefits, although longer-term, still occur relatively early in the overall expected life of the assets, which is over 40 years for the main components. Since these longer-term benefits do not arise for options involving interconnection with other states, omitting them would result in material differences in the benefits expected between options not being taken into account in the investment decision. Adopting a shorter assessment period therefore risks identifying a suboptimal option as preferred.

---

254 This memo has been released alongside this PACR.

255 TEP submission, 31 August, p. 20.

Notwithstanding the above, we recognise The Energy Project's concerns in relation to the uncertainty relating to these longer-term benefits (due, for example, to uncertainty in the timing of NSW coal plant retirement, or the extent of future REZ transmission requirements). However, this should be reflected in the RIT-T analysis via scenarios or sensitivity testing, rather than through truncating the assessment period. This has been done in the PACR analysis and is discussed further below.

Inclusion of terminal values

In discussions with The Energy Project following the original submission, we noted that their analysis did not incorporate 'terminal values' at the end of the assessment period, to recognise that where options involve long-lived assets, these assets continue to have a value at the end of the assessment period.

Inclusion of terminal values for long lived assets within the RIT-T assessment (and as part of cost benefit analysis more generally) is not unique to ElectraNet or this specific RIT-T analysis.

The AER's RIT-T Guidelines advise that relevant and material terminal values should be included within RIT-T assessments, where appropriate.[256] The inclusion of terminal values is also consistent with standard cost benefit analysis. For example, Commonwealth Department of Finance guidance states:[257]

> 'When conducting a [cost benefit analysis (CBA)], all of the benefits and costs of a programme or project should generally be discounted over the life of the programme or project. […]. Where a shorter timeframe is adopted, <u>it is critical that a terminal value be included in the CBA</u>, to reflect all subsequent benefits and costs'. (emphasis added)

Similar guidance is provided in recent guidelines published by other government and public bodies, including Infrastructure Australia and NSW Treasury.[258]

The use of terminal values ensures that options with differing asset lives (and different mixes of capital and operating expenditure) are assessed on the same basis. The use of terminal values is an alternative to either conducting the analysis across the whole of the asset's life (which in this case would be more than 40 years), or instead estimating capital costs on an annual basis[259] for each year of the assessment period.

Terminal values can be calculated either in relation to the residual cost of the asset at the end of the assessment period, or for the residual value of the benefit streams expected over the remainder of the asset life.

---

[256] AER, *Regulatory Investment Test for Transmission Application Guidelines*, 14 December 2018, p. 63.

[257] Commonwealth Department of Finance, *Introduction to cost-benefit analysis and alternative evaluation methodologies*, Financial management reference material no. 5, January 2006, p 22.

[258] For example, see: Infrastructure Australia, *Assessment framework for initiatives and projects to be included in the Infrastructure Priority List*, March 2018, p 90; New South Wales Treasury, *NSW Government guide to cost-benefit analysis*, March 2017, p 55; Transport and Infrastructure Council, *Australian transport assessment and planning guidelines | Cost benefit analysis*, May 2018, p 16.

[259] ie, including an estimate of the return on and return of (depreciation) of the investment in each year, rather than incorporating the entire investment cost in the year in which it is incurred.

For RIT-T assessments, including those on which the AER has made a determination, the standard approach is to apply a terminal value that reflects the remaining undepreciated cost of the assets at the end of the assessment period. Inclusion of a terminal value for asset costs is consistent with approaches adopted more generally for cost benefit analysis,[260] and avoids the need to project future benefit streams beyond the assessment period, which are subject to greater uncertainty.

The approach adopted by The Energy Project in its original submission and in the re-presented 'Original Approach' in its supplementary submission does not include a terminal value. In effect, the Original Approach does not account for the fact that at the end of 15 years there would still be a relatively young asset with many future years of benefit potential for the interconnector options (the full cost of which has been included in the analysis), whereas for the non-interconnector option (Option A) at the end of the 15 year period additional costs would need to be incurred by ElectraNet to extend the arrangements in order to realise any future benefits.[261]

Following discussions with ElectraNet, The Energy Project presents revised analysis in its supplementary submission that does incorporate terminal values, although still conducted over a 15 year assessment period.[262] In contrast with the 'Original Approach', once terminal values are included in The Energy Project's analysis, the non-interconnector option (Option A) is shown as having the *lowest* net market benefit,[263] substantially below the majority of the interconnector options assessed.

The Energy Project's assessment over a 15 year period including terminal values has the preferred option in the PADR (Option C.3i) ranked second, with a net market benefit only slightly behind the highest ranked option (Option C4 – 275 kV), despite this assessment not incorporating the substantial benefits that are expected to accrue across the options in the medium to long-term.

This finding, once terminal values are incorporated, is different from The Energy Project's conclusion in the original submission that 'ElectraNet's preferred option from the PADR no longer ranks that highly'.[264]

Our assessment based on the updated analysis in this PACR is that adopting a 15-year assessment period and incorporating terminal values continues to result in Option C.3 having the greatest net market benefit.

We have also undertaken a robustness test of the PACR assessment excluding the impact of terminal values, which continues to show that Option C.3 is preferred and has a positive net market benefit, even with a zero terminal value assigned.[265]

---

260 See for example, Infrastructure Australia, *Assessment framework for initiatives and projects to be included in the Infrastructure Priority List*, March 2018, p 90 and p152; Transport and Infrastructure Council, *Australian transport assessment and planning guidelines | Cost benefit analysis*, May 2018, p 20 (which recommends an estimation approach for terminal values based on straight-line depreciation).

261 That is, the cost of the non-interconnector option is limited to the costs of providing network support for 15 years.

262 TEP Supplementary Submission, 6 November, Section 4.2 'Inclusion of terminal values'.

263 Moreover, Option A is shown as having a *negative* net market benefit.

264 TEP submission, 31 August, Executive Summary p. 5.

265 See section 8.6.6.

Depreciation over 15 years

The Energy Project presents analysis in its supplementary submission that considers the net market benefit of the different options assuming that the full cost of the investment is depreciated over a 15 year period.[266] This assessment is effectively evaluating the 'payback period' for the investment, and, in particular whether the market benefits provided by the investment are sufficient to recover the costs over a 15 year period.

The payback period is a relevant measure to consider in understanding the nature of the risks associated with the selected investment, and in particular how far into the future benefits are required to justify the investment. Such consideration can inform a view on the extent of the risks borne by consumers in relation to the option, alongside the sensitivity analysis.

However, we do not consider that this is an appropriate metric to adopt to *select* options. Adopting this approach would be likely to result in frequent incremental investments that provide near term market benefits being selected over more transformative investments that are expected to provide substantially greater benefits (even after taking into account uncertainties in relation to these longer term benefits). This concern with an incremental focus on investments drove Finkel's recommendation that AEMO produce the ISP.[267]

> The long-lived nature of investment in the electricity system means that investments made today will significantly shape the network of the future. Incremental planning and investment decision making based on the next marginal investment required is unlikely to produce the best outcomes for consumers or for the system as a whole over the long-term [..].

Further, the full cost of the investment will in practice not be recovered by consumers over a 15-year period. Rather, it will be recovered over the projected life of the asset, which is substantially longer (40 years and above for the main components).[268] The cost borne by consumers over 15 years is therefore substantially lower than the cost included in The Energy Project's analysis.

If applied in order to select the preferred option, this analysis would suffer from the same problem as The Energy Project's Original Approach (which excludes terminal values), in that it incorporates all of the costs of the investments but does not also capture all of the benefits expected to be provided by that investment.[269]

Notwithstanding that we do not consider the 'rapid depreciation' approach to be appropriate in identifying the preferred option, we agree that calculating the implied payback period for the preferred option is a relevant additional metric to understand in considering the risks associated with the realisation of benefits associated with the option.

[266] TEP Supplementary Submission, 6 November, Section 4.3 'Rapid depreciation'.

[267] Dr Alan Finkel AO, *Independent Review into the Future Security of the National Electricity Market*, June 2017, p. 123,

[268] Recovery over a 15 year period would require ElectraNet to propose, and the AER to accept, an accelerated depreciation profile for the SAET assets. This is not currently contemplated and would raise equity concerns, as it would result in current customers paying for an asset which is expected to also provide benefits to future customers, who may differ.

[269] We also note that the 'rapid depreciation approach' has not been applied consistently between the interconnector and non-interconnector options. This is discussed further in the following section.

We have therefore calculated the implied payback period for Option C.3 on the basis of the analysis in this PACR and have found that the market benefits realised from the investment are expected to exceed the investment cost (in NPV terms) nine years from energisation under the central scenario.

Shorter assessment period, rapid depreciation and 30 per cent lower costs for Option A

The fourth and final assessment presented in The Energy Project's supplementary submission combines a 15 year assessment period with full cost recovery of the investment over 15 years and assuming a 30 per cent lower cost for the non-interconnector option (Option A). The Energy Project comments that:[270]

> Option A re-emerges as the preferred option under this case – highlighting the sensitivity of the non-interconnector options to the assumptions made with respect to annualised network support payments

We discuss below our view that the costs of the non-interconnector option (Option A) have not been overestimated in the PACR analysis, as they reflect the costs that have been proposed to us by non-network proponents that are prepared to provide those solutions.

Notwithstanding this view, in order to reflect The Energy Project's concerns, we have tested the sensitivity of the identification of the preferred option in the PACR to a 30 per cent reduction in the assumed annual network support payments made under the non-interconnector option (Option A),[271] whilst keeping the costs of the interconnector options constant. This sensitivity shows that Option C.3 remains the preferred option, even if the costs of Option A were assumed to be 30 per cent lower.

We note that the sensitivity we have conducted differs from that conducted by The Energy Project, as The Energy Project's analysis combines both an assumed 30 per cent lower cost for Option A <u>and</u> restricts benefits to a 15-year period whilst including the full cost of each option (ie, assumes accelerated depreciation).[272]

As a consequence, this remains an assessment of relative payback periods, rather than illustrating the sensitivity to the costs of annual support payments. As discussed above, we do not consider identification of the preferred option on the basis of a 15-year assessment period and assuming accelerated depreciation to be an appropriate approach.

We also note that the 'rapid depreciation' approach has not been applied consistently between the interconnector and non-interconnector options in The Energy Project's analysis. The annual opex costs associated with Option A are based on cost recovery of a portion of the capital investments underlying provision of the non-network components by proponents. This also needs to be re-calculated over a 15 year period under this approach, which will increase the costs of Option A.

---

[270] TEP Supplementary Submission, 6 November, p. 9.

[271] See section 0.

[272] In order to test the impact of the assumed Option A costs, The Energy Project would have needed to have run this sensitivity under their section 4.2 assumptions – where it would not have resulted in Option A being preferred.

Appropriate treatment of uncertainty

The key concern expressed by The Energy Project is that the identification of the preferred option in the PADR 'relies heavily' on outcomes that are a long way into the future and come with significant uncertainty and hence risk for consumers.[273]

As discussed above, The Energy Project analysis of the PADR results incorporating terminal values[274] shows that the preferred option is ranked second even under a 15-year assessment period, with net benefits only slightly below those for the front ranked option. The extent to which identification of Option C.3 as the preferred option in the PADR relies on benefits that accrue after 15 years is therefore not as substantive as portrayed by The Energy Project.

Notwithstanding, we fully recognise The Energy Project's concern that the substantive nature of the investment being assessed means that it is important to ensure that the anticipated benefits are robust to a range of future potential outcomes, in order to be confident that they are indeed in the long-term interests of consumers.

However, under the RIT-T framework, uncertainty is addressed via the use of scenarios reflecting difference future market development, rather than through a truncation of the assessment period.

As highlighted in the PADR, and again in this PACR, the role of scenarios and sensitivity analysis is to assess how different future outcomes may affect the benefits associated with different investments.[275] The AER RIT-T Application Guidelines explicitly refer to the role of scenarios as the primary means of taking uncertainty into account:[276]

> Where the calculation of the market benefits or costs of a credible option is affected by material uncertainty over the future market supply and demand conditions and characteristics, this is to be primarily reflected in the choice of the range of reasonable scenarios.

Uncertainty in relation to future outcomes, given the long-lived nature of transmission assets, is inevitable. It is clear that the energy sector is currently in transition, and there are even more significant risks in taking no action to support this transition.

We do not therefore agree with The Energy Project's assertion that demonstrating that an investment is in the long-term interests of consumers '[relies] on a stable electricity policy environment'.[277] Rather, demonstrating that an investment is in the long-term interests of consumers requires demonstrating that the preferred option continues to provide the greatest net market benefit across different plausible future policy environments (as well as different future market circumstances more broadly).

---

[273] TEP, Supplementary submission, 6 November, p. 10.

[274] As set out in section 4.2 of TEP's supplementary submission.

[275] See section 4.4.4 of the PADR, and section 7.1 of this PACR.

[276] AER RIT-T Application Guidelines, 18 September 2017, p. 30. This was also reiterated in the recently updated Guidelines, see: AER, RIT-T Application Guidelines, December 2018, p. 42.

[277] TEP, submission, 31 August, Executive Summary, p. 5.

In relation to current energy policy uncertainty, for the SAET RIT-T we have assessed different future emission targets (ranging from no explicit reduction target beyond the current RET, to a 52 per cent reduction by 2030) as part of forming reasonable scenarios.[278] Our assessment has demonstrated that Option C.3 delivers the greatest net market benefit across all of these scenarios, making it a ‘no regrets’ option.

The assessment in this PACR also includes sensitivity analysis in relation to:

- higher than anticipated NSW coal prices, leading to earlier than expected NSW coal plant retirement;
- the potential for a SA-Queensland interconnector option (Option B) to defer the second stage of a QNI upgrade;
- the outcome of the coincident Victorian RIT-T being undertaken by AEMO;
- removing the minimum operation constraints on these plants (ie, consistent with the approach taken the PADR);
- assuming that all units of Torrens Island B retire at or before 50-years of age under the base case;
- assuming a new interconnector has no impact on the operation of Pelican Point and Osborne (ie, they do no retire nor change their behaviour);
- lower assumed avoided REZ transmission cost benefits;[279]
- lower assumed non-network costs;
- lower HVDC costs compared to HVAC costs;
- a shorter assessment period;
- removing terminal values from the assessment; and
- other general sensitivities, ie, discount rates, capital cost estimates.

This expanded list of sensitivities from those considered in the PADR reflects points made by The Energy Project, as well as other submissions, on key uncertainties. These sensitivities continue to show the preferred option (Option C.3) as having the highest net market benefit.

Finally, while we note the comments made by The Energy Project in its original submission on potential alternative funding arrangements for transmission associated with REZs that incorporate generator contributions,[280] we do not consider that this would have a material impact on the RIT-T assessment. The costs of these transmission investments would be captured within the RIT-T assessment whether they are paid for by customers or generators, as both are NEM participants.

---

[278] We have also not restricted the modelling to the adoption of any specific policy to achieve these outcomes.

[279] This sensitivity mirrors the one undertaken in the original The Energy Project submission (p. 21), although with terminal values correctly incorporated, and updated to reflect the PACR analysis.

[280] TEP submission 31 August, p. 21.

Discount rate

The RIT-T analysis applies a discount rate in assessing future costs and benefits. This has the effect of discounting benefits that are anticipated to occur further into the future, compared with near-term benefits. Because of compounding, the impact of the discount rate increases the further benefits are into the future.

The application of a discount rate directly addresses The Energy Project's concern in relation to a reliance on benefits that accrue in the longer term.

The Energy Project submissions make two comments in relation to the discount rate used in the SAET RIT-T assessment.

The first is that the lower bound regulated discount rate adopted in the SAET RIT-T should not be based on current settings but on an estimate over the 22 year time horizon.[281] In practice it is not possible to formally estimate the future regulated discount rate, and that the sensitivity analysis conducted as part of this RIT-T tests the robustness of the outcomes to a range of discount rates above this lower bound value (noting that The Energy Project refers to the current value as reflecting a 'low point in the business cycle').

The second point made by The Energy Project is that the 6% (real, pre-tax) central discount rate adopted in the RIT-T analysis is not reflective of either 'the risk facing customers'[282] or 'the hurdle rate a business customer would apply to an energy investment'. [283]

The choice of discount rate in the RIT-T assessment is required to reflect 'a commercial discount rate applied to private sector investments in the electricity sector'. The 6 per cent central discount rate is in line with other recent RIT-T assessments.[284]

We have tested the sensitivity of the assumed discount rate to a lower bound of 3.8 per cent and an upper bound of 8.5 per cent, and find that Option C.3 continues to be identified as the preferred option within this range.[285]

F.2 Risk of over estimation of costs of non-interconnector option (Option A)

The costs of the majority of components for the non-interconnector option (Option A) have been estimated on the basis of prices set out in responses by non-network proponents to the earlier PSCR. These prices are commercial-in-confidence and therefore have not been disaggregated in this PACR (or the earlier PADR).

---

281 TEP supplementary submission, 6 November, p. 10.

282 TEP submission, 31 August, p. 23

283 TEP supplementary submission, 6 November, p. 10.

284 Including that used by AEMO in its current Western Victoria RIT-T and that used by TransGrid and Ausgrid in the 2017 Powering Sydney's Future RIT-T, as well as by Ausgrid and Jemena in recent RIT-Ds. We note that Powerlink has used a slightly higher central discount rate of 7.04 per cent in its recent repex RIT-Ts, which is within the sensitivity tested in this PACR.

285 See section 8.5.5. We note The Energy Project's assertion in its original submission (p. 22) that 'the NPV results appear to be quite sensitive [..] to discount rates'. The analysis presented in section 8.5.5 refutes this statement.

The Energy Project presents estimates of the costs of individual components of Option A in its August 2018 submission, drawn from public sources. On the basis of this analysis, The Energy Project concludes that the costs of Option A may have been overestimated in the PADR assessment.

Whilst noting the analysis presented by The Energy Project, we reconfirm that we have used the prices that have been proposed to us by non-network proponents who would be willing to provide the services sought at these prices in the cost estimate for Option A.

These prices comprise over 60 per cent of the overall costs of Option A, and for some elements are substantially higher than those estimated by The Energy Project. Two of the non-network proponents who submitted those prices have continued to engage with us and made submissions to the PADR which have not altered the prices at which they have said they are prepared to provide these solutions.

In response to The Energy Project's submission and others, we have however looked further into the costs of the battery storage component of Option A (which have been estimated by ElectraNet) and have taken into account the opportunities for additional revenue streams in further refining the costs of this component, which have now reduced by approximately 15 per cent.

Notwithstanding the above, the PACR also includes a sensitivity in which the cost of Option A is 30 per cent lower than our central assumption. This sensitivity does not change the preferred option.[286]

F.3 Allocation of risks and costs between regions

The Energy Project submissions comment that the allocation of costs and benefits seem imbalanced between South Australian and NSW consumers.

Under the NER, where transmission assets in one region are used to supply customers in another region, part of the cost of those assets are charged to customers in the importing region through an 'inter-regional TUOS' or 'IR-TUOS' charge.

The Energy Project acknowledges that the RIT-T does not require the inclusion of any estimates of the allocation of costs and benefits between regions or the impact of the IR-TUOS regime. However, they express the view that it would help customers engage in the RIT-T process if it was available.[287]

The current arrangements for determining IR-TUOS have been in place since February 2013 and were intended to make TUOS charges more reflective of the actual costs incurred in providing transmission services. However, the current regime only takes into account peak annual usage for each asset and does not consider the extent of energy flows between regions, or the contribution assets make to providing system strength or contributing to system stability in other ways.

[286] See section 0.

[287] TEP submission, 31 August, p. 16.

We would support a broader review of the continuing suitability of the current IR-TUOS arrangements, and whether modifications would result in a more equitable allocation of costs between customers in different regions based on the benefits that assets provide to those regions, regardless of the asset's geographic location. Notwithstanding this, the appropriateness of the current IR-TUOS arrangements is an issue that is separate to this RIT-T application, and modifications to the arrangements are not precluded by the outcome of this RIT-T.

Because it is based on the peak utilisation of each asset, forecasting IR-TUOS charges is both complex and highly uncertain. Our experience has been that IR-TUOS charges can fluctuate substantially from year to year for interconnector assets. We have not therefore attempted to forecast IR-TUOS as part of this PACR.

We note that the AEMC recently stated, as part of its final report on the coordination of generation and transmission investment in December 2018, that there may be some elements of the existing inter-regional transmission charging arrangements that could be changed to better align the costs of interconnectors with those that benefit from the investment.

The AEMC recommends that these should be considered in more depth through re-examining the IR-TUOS arrangements, and work will commence on this in March 2019.[288]

F.4 Recommendation for staged investment in the NSW elements of the project

A key recommendation that The Energy Project draws from their analysis is that 'given the apparent imbalance between costs and benefits of the preferred option between SA and NSW consumers, a more strategically timed approach to the NSW elements may better align the costs and benefits for NSW consumers'.[289]

Specially, The Energy Project recommends that ElectraNet and TransGrid explore options that include elements of the non-interconnector option (Option A) with staged investment in the NSW elements of the project - such as Option C.2 (275 kV line from Robertstown to Wagga Wagga) and series compensation.

As set out in the earlier PADR, we have considered the potential to stage investment in a new interconnector. We concluded that it would be uneconomic and may not meet the identified need to partially build HVAC lines, for example by stringing one side of a double circuit line initially.

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). Moreover, stringing one-side only may not meet the identified need as the non-credible loss of Heywood cannot then be managed.

We also note that the benefits that have been identified in relation to the alternative options rely on the entire investment being in place. In the case of a new South Australia-New South Wales interconnector, the expected near-term benefits accruing in South Australia would not be realised in the absence of the investment on the New South Wales side of the border.

[288] AEMC, *Coordination of Generation and Transmission Investment*, Final Report, 21 December 2018, p. viii.

[289] TEP submission, 31 August, p. 25 and TEP Supplementary submission, 6 November, p. 11.

There is therefore no scope to adopt 'a more strategically timed approach to the NSW elements'[290] of the investment without forgoing the substantial benefits that are expected to begin accruing immediately the investment is put in place.

Finally, in relation to considering the scope for non-network investments to supplement network investments, we have considered this in section 5.5. The summary of this assessment is that ElectraNet considers that there is not a clear need to include interim arrangements before a new interconnector is energised.

We acknowledge that there may a role for these solutions to further increase net market benefits in combination with increased interconnection. Any such consideration will be undertaken through a separate RIT-T process. A full discussion of this assessment of interim investments, including the additional support considered, can be found in the accompanying Entura report.

[290] The Energy Project, August submission, p. 25 and November supplementary submission, p. 11.

Appendix G Detailed response to points raised by ARCMesh

Summary points:

- Under the market modelling conducted for this PACR, Queensland coal plant does not retire until the end of its technical life, under all of the alternative interconnector routes considered (not only the South Australia – Queensland interconnector option).
- We have further reviewed the costs of the HVDC components of the South Australia – Queensland option, and have reduced the estimated line costs.
- We engaged independent consultant Jacobs to review the cost estimates of the major HVDC and HVAC transmission line components of the options considered, taking into account the detailed comments on the specification of the option in the ARCMesh submission (including the potential to adopt guyed towers) – the Jacobs report is published alongside this PACR.
- We have also undertaken a further sensitivity by reducing the costs of the South Australia – Queensland option by 25 per cent while leaving the costs of the other options unchanged to account for other factors raised in the ARCMesh submission (equivalent to reducing the line costs of the option by 50 per cent) – this sensitivity continues to find that the Queensland HVDC option is not preferred.
- We have also taken into account the potential avoided REZ transmission costs associated with the South Australia – Queensland option (although note that realising these benefits requires the addition of a third converter station).
- Whilst recognising the technical advantages of HVDC technology over HVAC technology in relation to system security benefits, these benefits have now become a smaller proportion of the overall benefits associated with the options considered in this RIT-T, due to the requirement for more immediate measures to be put in-place.

This appendix provides a detailed response to points raised by ARCMesh, both in its submission to the PADR as well as during participation in the stakeholder deep dive sessions held as part of our detailed consultation on this RIT-T.

This appendix has been prepared in addition to the summary of submissions (and ElectraNet responses) included in the main body of the PACR, and the detailed table of issues raised in consultation (and ElectraNet responses) presented in Appendix C.

The issues are presented below in the order in which they are raised in the ARCMesh submission.

G.1 SA-Queensland interconnection would enable efficient use of modern Queensland coal generation fleet

ARCMesh highlights what is sees as the potential impact of non-Queensland interconnector routes on the “side-lining” and “premature retirement” of some of the NEM’s five most modern and efficient coal-fired power stations, all located in Queensland. [291]

[291] ARCMesh, pp. 2-5.

ARCMesh submits that, in contrast, the South Australia - Queensland interconnector option would enable the efficient utilisation of the Queensland coal fleet over its full technical life.

It also claims that the South Australia-Queensland route would relieve constraints on QNI, providing an additional 350 MW (minimum) of increased QNI export capacity, from increasing QNI stability limits,[292] with virtually no incremental capital investment.

ARCMesh considers that the PADR has as a consequence underestimated the economic benefits of the South Australia - Queensland option (Option B) by 'at least' $5 billion to $10 billion, and that none of the other options have these potential additional economic benefits. ARCMesh considers that both AEMO and ElectraNet should have considered these benefits.

ARCMesh's contention appears to be based on an understanding that the non-Queensland interconnector options result in the premature retirement of Queensland coal generators. However, this is not the case. Under the market modelling conducted for the PADR and for this PACR, these Queensland coal plants do not retire before the end of their technical life. This is also consistent with AEMO's assessment in the ISP. The first Queensland coal plant that is forecast to retire in the modelling is the Gladstone units, in 2029.

While the wholesale market model used does allow for generators to retire early, we have tested the impact of each of the credible options (including Option B) on the pattern of generation retirements and have not found that any options influence the timing of generator retirements outside of South Australia.

In relation to the future utilisation of the Queensland coal fleet, ElectraNet has taken into account the potential for increased interconnector limits on QNI. The base case for the market modelling in this PACR now includes both stages of the proposed upgrade to QNI, consistent with the optimal network development path identified by AEMO in the ISP.

This upgrade will enable Queensland coal generation to be utilised to directly supply load in New South Wales (rather than the much smaller South Australian load centre).

Based on advice from Powerlink, Option B has been assumed to improve the QNI transfer limits by 250 MW. As a result of this improvement in QNI transfer limits we have also explicitly considered the potential for a South Australia – Queensland interconnector route to defer the second stage of the QNI upgrade, and report on the results of this sensitivity in section 8.5.1.

Even assuming the ability to defer the QNI upgrade, Option B was not found to become the preferred option. This is driven by the finding that, while there is a benefit of approximately $195 million due to the deferral of the Stage 2 QNI investment by ten years, the estimated fuel cost savings for Option B decline substantially (on account of the Stage 2 investment being deferred).

[292] ARCMesh, p. 4.

G.2 Estimated capital cost of South Australia - Queensland HVDC interconnector

The PADR estimated the capital cost of Option B, HVDC VSC[293] from South Australia to Queensland to be $1,790 million (or $1,090 million in NPV terms).

ARCMesh noted that it has undertaken extensive assessments of the optimal scope and design of an HVDC VSC interconnector from South Australia to Queensland using 'at least [..] three alternative methods', drawing on expert input and published costs for recent projects. The average cost of the methods used is $1,435 million, with an accuracy of 15 per cent, and a variance of $50 million or around 3%. This includes estimates based on the cost of guyed structures at $0.52 million/km and free-standing structures at $0.72 million/km.

ARCMesh therefore considers that the costs of the HVDC option could be 24 per cent lower than those estimated in the PADR,[294] due to the 'implausible assumptions made by ElectraNet in scoping, designing and estimating the cost of their Option B'.[295] ARCMesh makes a number of very detailed comments on aspects of the specification of Option B and the associated cost estimates.[296] It also calls for the costings for the major components of the option (lines, converters, AC substations etc) to be broken out, in order to provide a reasonable level of transparency.

ARCMesh also considers that a superior route for the Queensland option to that proposed in the PADR would be to head due west from southeast Queensland, parallel to the Queensland and New South Wales border.[297]

ARCMesh states that this route would traverse an extensive series of good access tracks and existing gas and oil pipeline easements, and has minimal heavily cultivated land and is mostly ideally suited to the use of guyed cross-rope structures. This would reduce the costs of the option.

In selecting the appropriate route to assess the HVDC line, we focused on identifying the shortest route, given the material costs of the line and the relationship between line length and overall costs. We consider that any potential savings identified by ARCMesh in relation to the route it has outlined will be more than offset by the ten per cent longer route length (which we understand to be 1,600 km rather than the 1,450 km assumed for Option B).

We also engaged independent consultant Jacobs to provide a technical review of the cost estimates of the major HVDC and HVAC transmission line components of the options considered, taking into account the detailed comments on the specification of the option in the ARCMesh submission (including the potential to adopt guyed towers). The Jacobs report is being published alongside this PACR.

We also further reviewed the costs of the HVDC components of the South Australia - Queensland option, in the light of the information provided by ARCMesh.

---

[293] Voltage Source Converter (VSC) is one of the two main types of converter topologies for HVDC systems.

[294] ARCMesh, p.8.

[295] ARCMesh, p.8.

[296] See ARCMesh, p. 5-8.

We have added a high-level breakdown of the cost estimates of each interconnector option considered in Appendix I of this PACR.

This further work has resulted in modifications to both the scope and costing of Option B in the PACR. In particular:

- based on the Jacobs review the HVDC unit line cost has been reduced to $655 thousand/km to take account of an increased proportion of guyed towers;
- this has reduced the HVDC line cost across the route length by $88 million;
- a midpoint HVDC converter station has been added to capture REZ transmission benefits (in line with ARCMesh's calls for these benefits to be taken into account for the SA-NSW option); and
- the costs of the third HVDC converter station more than outweigh the reduction in costs from the reduced unit line costs.

We have also considered the benefits associated with avoided REZ transmission costs compared to the costs of the third converter station required to realise those benefits, and recalculated the net benefit *excluding* the third converter station costs in order to identify the incremental impact on the net market benefit of Option B of this converter station.

In addition, notwithstanding the above, we have undertaken a further sensitivity by reducing the costs of the SA-Queensland HVDC option by 25 per cent, whilst leaving the costs of the other interconnector options unchanged. This 25 per cent reduction in the total cost of the option is equivalent to the HVDC line cost reducing by 50 per cent.

This sensitivity is reported in section 8.6.3, and continues to show that the Queensland HVDC option is not preferred.

G.3 Estimated cost of South Australia – New South Wales interconnector options

ARCMesh's submission raises what it considers to be a potential inconsistency in the comparison of the 275 kV line costs presented in ElectraNet's Eyre Peninsula RIT-T compared to the 330 kV line cost presented in the SAET PADR for the South Australia – NSW option, which it considers points to the costs of the 330 kV line options being understated. [298]

In particular, ARCMesh comments that the cost estimates for 275 kV options (without 275 kV substations) presented in the Eyre Peninsula RIT-T were around $1,140 k/km ($2017), although it notes that this excludes transmission line easements.

Escalating to 2018 prices and adding a 5-10 per cent premium based on Queensland experience of the typical increase in costs for 330 kV lines compared to 275 kV lines, ARCMesh derives a cost estimate of around $1,250 k/km for 330 kV double circuit HVAC lines. ARCMesh comments that the cost estimates presented for the South Australia – New South Wales options in the SAET PADR are only 77 – 81 per cent of these estimates.

[298] ARCMesh, p. 9.

Table 14 demonstrates that the net lines cost for the Eyre Peninsula RIT-T were in fact significantly below the $1,140 k/km figure presented by ARCMesh, both at the PADR and PACR stage of this RIT-T.

Table 14 – Lines costs used in the Eyre Peninsula RIT-T

Line cost component/breakdown	PADR	PACR
Overall Eyre Peninsula line cost	$269 million	$232 million
Overall line length	269 km	269 km
Net cost per km	**$1,000 thousand**	**$ 862 thousand**

The 275 kV SAET costs varied between 4 per cent lower and 12 per cent higher than those used in the Eyre Peninsula PADR and PACR, respectively. Similarly, the 330 kV SAET costs varied between 6 per cent higher and 23 per cent higher than the 275 kV lines costs used in the Eyre Peninsula PADR and PACR, respectively.

ElectraNet provided the basis of the $1,013 k/km estimate for 330 kV double circuit HVAC line used in the PADR in the Basis of Estimates report published alongside the PADR. ARCMesh comments in its submission that the low estimate received from one vendor (and which is reflected in the $1,013 k/km estimate) should have been excluded as an outlier, and possibly replaced with ElectraNet's Eyre Peninsula estimate. ARCMesh estimates that this would add $30 million to the costs of the South Australia – NSW option.

ElectraNet engaged independent consultant Jacobs to provide a technical review of the cost estimates of the SA-NSW 330 kV AC options, taking into account the comments on the cost estimates in the ARCMesh submission. The Jacobs report is being published alongside this PACR.

ElectraNet has also further reviewed the costs of the SA-NSW option, in the light of the information provided by ARCMesh.

This further work has resulted in modifications to both the scope and costing of Option C.3 in the PACR. In particular:

- both substation as well as reactive plant specifications have been refined; and
- based on the Jacobs review the 330 kV HVAC unit line cost has been increased to $1,061 thousand/km.

ARCMesh also comments that the South Australia – NSW option only goes as far as Wagga, but that there would ultimately be a requirement to augment the Wagga to Yass 500 kV transmission line, at a cost of $500 million. ARCMesh considers that the 'bring forward' value of this longer term augmentation should also be reflected in the RIT-T assessment.

ElectraNet has modelled the network between Wagga and Sydney and agrees that congestion along this corridor increases with Option C3 in service compared to the base case. That is, there is a potential market benefit in augmenting this path in addition to Option C3.

However, while the interconnector will not always be capable of flowing at full capacity into NSW, this is accounted for in the market modelling and hence the calculation of benefits.

Should the network between Wagga and Sydney be augmented, this would further improve the economics of Option C3. We also note that Snowy 2.0 is likely to augment this corridor, alleviating these constraints.

G.4 Choice of HVDC VSC vs HVAC technology

ARCMesh highlights in its submission a view that the HVDC VSC option is superior to HVAC options and the need to recognise more of the technical benefits provided by the HVDC technology in the assessment.[299]

ARCMesh considers that neither AEMO (in the ISP) nor ElectraNet have adequately taken these benefits into account, and that they are particularly pertinent to the relatively weak South Australian power system. ARCMesh considers that these benefits would be in the order of ‘at least $500 million’ based on the costs in the ElectraNet PADR and AEMO ISP, although does not provide the basis on which this figure has been derived.

The advantages of HVDC VSC technology compared to the classic HVDC LCC[300] technology as well as HVAC technology is understood. These include benefits relating to lower transmission losses, improved transient stabilisation (rapid response), four quadrant reactive power control, inertia and system strength support, black start features, dynamic and steady state power control and the provision of FCAS.

It is worth noting that for HVDC VSC systems to provide inertia or system strength similar to synchronous generators, the HVDC VSC system has to be oversized and also have a suitable energy source on the DC side. This would not be the case before the DC link between South Australia and Queensland is built. A more detailed comparison of the relative merits of HVAC and HVDC transmission systems is provided in Appendix H.

We have taken these technical characteristics into account in determining the scope of the HVDC option in this RIT-T. For example, there is no additional reactive power plant included in the HVDC option, while the HVAC options include shunt reactors and shunt capacitors at various locations to supplement the power transfer and system security capabilities.

However, more fundamentally, the diminishing role of system security benefits in contributing to the overall market benefits under this RIT-T[301] means that the benefits associated with HVDC technologies are less material to the outcome of the assessment than may have been envisaged at the start of the RIT-T process.

Given the interest in HVDC solutions more broadly, we have continued to evaluate the HVDC option for SA – Queensland interconnection in this PACR, and have also added a new HVDC option for SA – NSW interconnection (Option C3.iii).

---

[299] ARCMesh, p. 9.

[300] Line commutated converter (LCC) is the second main type of converter topology for HVDC systems.

[301] Due to the other more immediate measures that have been put in place to address system security in South Australia

G.5 Potential to facilitate new renewable generation

There is the potential for additional benefits to be derived from the ability to connect new generation along the interconnection route, if it were to pass closer to areas of strong renewable energy development potential.

We acknowledge that the route can be developed to capture benefits of solar and other renewable generation along the interconnection path (including the potential Broken Hill REZ identified in the ISP).

ARCMesh queried whether these benefits have been included along routes other than the New South Wales route, noting that no allowance appeared to have been included for the Queensland route. These benefits were not included in the earlier PADR assessment for the Queensland route, but have now been included in this PACR assessment.

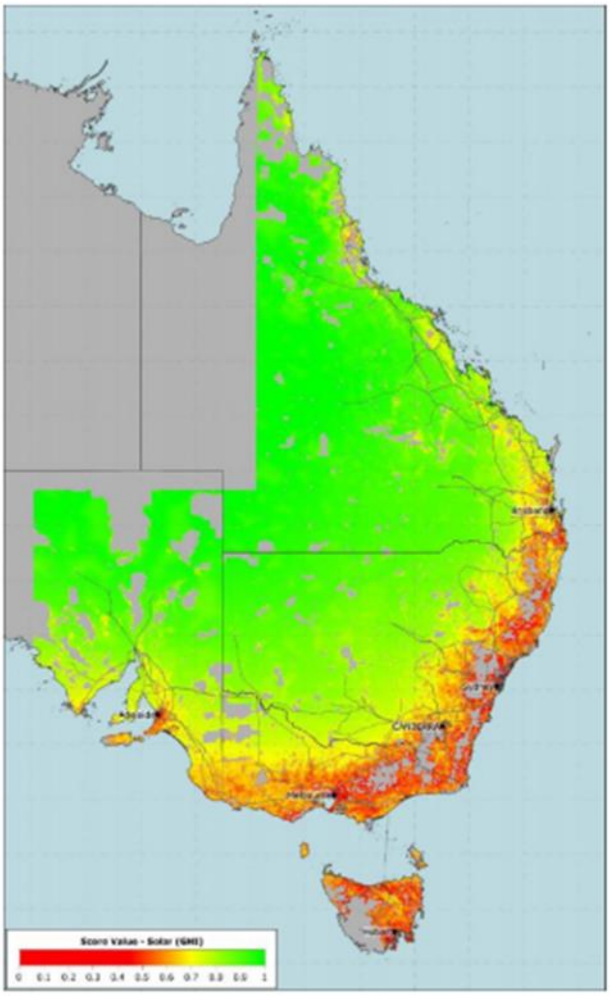
Specifically, we have added to the scope of Option B an additional mid-point HVDC converter station (indicatively at Broken Hill), which would be required in order to enable this generation to connect. However, adding converters to HVDC links adds significant cost, in comparison to tapping into HVAC lines to connect new generation. This therefore adds to the cost of the HVDC options in comparison to HVAC options.

The figure below presents the results of expert advice received by AEMO on solar resources in NEM states and shows that there is not expected to be materially better solar resources north of the Option B line route.

The magnitude of the benefit associated with avoided REZ transmission development for the South Australia-Queensland option was found to be in the order of $75 million in PV terms in the modelling undertaken for this PACR (under all scenarios).

This compares to the costs of a mid-point converter station in the order of $280 million (based on estimates provided by converter station manufacturers).

Figure 34 – Solar resources in NEM states



Source: http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/ISP-Appendices_final.pdf

G.6 Efficiency considerations

ARCMesh comments that the reduction in transmission losses across the NEM which can be achieved by a controllable HVDC solution has been under estimated in the calculation of loss benefits for the SA-Queensland option. In particular, ARCMesh states that, while DC power flow modelling is appropriate for AC interconnectors, it under-estimates the reduction in losses expected for HVDC.[302]

We do not agree with the view expressed by ARCMesh that transmission losses across the NEM have been under estimated. The major load centres in the NEM are on the eastern seaboard, due south from Queensland. By comparison South Australia is a small load centre and a South Australia-Queensland interconnector would exhibit more losses than an upgrade to QNI.

[302] ARCMesh, pp. 13-14.

However, we note that, even if the DC power flow did underestimate the reduction in losses, it is unlikely to be material in the identification of the preferred option.

ARCMesh comments that other benefits derived from access to high efficiency generation (including pumped storage in Queensland) are also not captured. Option B provides access to the higher cycle efficiency of Queensland's pumped storage schemes due to their large scale, high heads and short penstocks compared with the inefficient Snowy 2.0 scheme and the less efficient, smaller, low-head pumped storage schemes proposed elsewhere in NSW, SA and Victoria.[303]

We note that the modelling for this PACR has adopted assumptions relating to the relative efficiencies of different generation technologies that are consistent with those in AEMO's ISP. We are not aware of widely recognised evidence that would justify departing from these assumptions.

G.7 Construction lead times

ARCMesh considers that the construction time for SA - Queensland option should be one year less than for the SA - NSW options, due to the proposed structures, terrain and line routes. ARCMesh also comments that unless Australian shortages of skilled construction workers and specialised construction equipment are urgently addressed, the construction costs and construction times for the South Australia – NSW options are unlikely to be achieved.

Specifically, ARCMesh considers that the lead time for Option B is too long (and should be two years rather than three), and that for the SA-NSW options is too short (and should be three years rather than two).

We have further considered the appropriate routing and construction time for the South Australia – Queensland option. We do not consider the more inland route proposed by ARCMesh to be a credible alternative, as it would be around ten per cent longer and therefore attract a significantly higher cost.

Moreover, there is no recent experience of HVDC technology in Australia and it would be a complicated project. We therefore continue to be of the view that a three year construction period remains appropriate for the South Australia – Queensland option, and have assessed this option in the PACR on that basis.

We will continue to work closely with the South Australian Government and TransGrid to undertake early works to bring forward the completion timeframe of the preferred option as much as possible, so that the benefits of the project can be realised sooner.

The South Australian Government's underwriting of early works and the agreed framework for cooperation between the South Australian and New South Wales governments to expedite delivery of the project increases the likelihood of achieving a 2022 delivery date.

---

303 ACRMesh, p. 14.

G.8 Availability of design and construction skills, labour, specialised construction equipment

ARCMesh submits that an important practical consideration in assessing the cost, time and risks of delivering a major interconnection project in Australian is the availability in Australia of the required personnel to design and construct the transmission lines as well as the availability of the necessary specialised construction equipment in Australia.[304]

ARCMesh concludes that unless current Australian shortages of skilled construction workers and specialised construction equipment are urgently addressed (at very considerable expense), the construction costs and construction times of the NSW option will be higher compared to the Queensland option. This is because the converter stations for the HVDC option would be turn-key contracts mostly designed and built overseas, and the substation works are less extensive compared to line construction.

ElectraNet considers that the substation associated works of the NSW option to be well within the capability of the Australian electricity construction industry. The amount of substation works involved is not significant compared to the annual volume of substation work across the country.

We agree that there is potentially a very large amount of transmission line works required in the coming years across the NEM and having sufficient skilled line construction resources to undertake this work is a challenge that needs to be addressed. However, these risks exist for both the HVDC as well as the HVAC options.

G.9 Other points raised by ARCMesh

The table below provides responses to a number of additional matters raised by ARCMesh.

The detailed table of consultation issues included in Appendix C contains a number of more tangential issues raised by ARCMesh during the deep dive sessions (which are not repeated here).

[304] ARCMesh, p. 17.

Table 15 – Responses to additional miscellaneous points raised by ARCMesh

Point raised by ARCMesh	ElectraNet response
Option B is the only option to 'mesh the NEM' and is a solution to Australia's NEM interconnector design and the associated serious power system security and market aberrations. It is recommended that ElectraNet test Option B against Option C(i) for the incident that occurred in late August 2018 (ie, the tripping of QNI following a storm) and include the relative economic consequences in their economic comparison and recommendation.	ElectraNet acknowledges that Option B may improve the ability of the NEM transmission network to withstand specific high impact low probability (HILP) events in Queensland. However, under the RIT-T assessment framework, the costs of avoiding such events are only justified to be borne by consumers if outweighed by the associated benefit multiplied by the probability of the event occurring. Given the extremely low probability attached to a repeat of the August 2018 event, incorporating this assessment would not be expected to alter the RIT-T outcome.
What capacity was assumed for the Queensland interconnector option?	A capacity of 700 MW under summer conditions was modelled with a combined import transfer capacity limit of 1,300 MW to SA, equivalent to other interconnector options. In addition for Option B we have assumed an improved transfer limit of 250 MW across QNI. Additional detail is provided on these transfer limits in the separate PACR Market Modelling Report.
Option B would only require a minor additional investment to connect to the existing high capacity telecommunications systems in the Port Augusta area as well as substantially enhancing existing telecommunications services in those remote parts of inland Australia. The additional income could generate a substantial net benefit and revenue source that is allowable under the RIT-T that has not been factored into the assessment.	All interconnector options are assumed to have standard communications equipment. The benefit from additional revenue from telecommunications services suggested by ARCMesh would only be captured under the RIT-T assessment, where it is reflected in a potential external funding contribution, which would then reduce the costs incorporated in the RIT-T assessment. No such funding contributions have been proposed in this case. .
No details have been provided on the life-cycle O&M costs for either Option B or Option C(i). The O&M costs of Option B's HVDC transmission lines and primary equipment are expected to be lower than the equivalent operation and maintenance costs for Option C(i), as there are only approximately half the number of conductors and insulators and much less HVAC substation equipment.	HVDC VSC converters have more maintenance and the thyristor valves and controls need to be replaced in 20 to 30 years. Compared to this, the HVAC options have a design life of 45 to 55 years, with minimum maintenance. More fundamentally, the assumed O&M costs differences between the preferred option and the HVDC option are immaterial to the selection of the preferred option, given the more substantive relative differences in capital costs and the expected market benefits between options.

Point raised by ARCMesh	ElectraNet response
Substantial reduction in pool price volatility in the NEM, particularly in South Australia and Queensland.	All interconnector options deliver this outcome between their terminating regions. The HVDC options do not do this any more or less than the alternative options. Changes to volatility is not a class of market benefit considered under the RIT-T. A reduction in prices or volatility is not a benefit in itself that can be considered by the RIT-T. Rather, it is only the subsequent impact of such a reduction on consumption and investment decisions that affect RIT-T outcomes.
There is no discussion of whether diversity in renewable energy output has been modelled across regions.	Diversity over the timeframes considered is taken into account in the modelling. ElectraNet has adopted AEMO's assumptions in relation to wind diversity and PV output and the results in the PACR reflect these assumptions.
Only Option B aligns with a vision of an Australian grid exporting renewable energy to Indonesia.	We cannot see how only Option B aligns with the vision. The point has not been substantiated by ARCMesh.
HVDC inverters can respond with system strength. A DC option with early installation of converters would solve the immediate system strength problem.	The current system strength shortfall in South Australia needs to be addressed urgently and cannot wait for the development of a new interconnector. Synchronous condensers are needed urgently now whether a new AC or DC link is ultimately built, and are planned to be in place by 2020. It is worth noting that for HVDC VSC systems to provide system strength similar to synchronous generators, the HVDC VSC system has to be oversized and also have a suitable energy source on the DC side. This would not be the case before the DC link between South Australia and Queensland is built.
With the system strength shortfall declared, synchronous condensers will be required and are being pursued in three SA locations, but synchronous condensers are also being included in the preferred option.	Synchronous condensers are being implemented to meet the urgent need to address a system strength shortfall in South Australia. The synchronous condenser solution is included in the base case for the consideration of all options in this PACR. Synchronous condensers have been removed from the scope of the preferred option since the PADR.
How has the modelling simulated the effect of a controlled loop around the NEM in market dispatch?	A controllable DC load-flow model has been used to represent the network including network limits, with hourly dispatch runs to simulate security constrained optimised dispatch across the interconnected network. A controlled loop around the NEM has not been modelled due to the complexity that would be involved in such analysis, which is considered disproportionate and impractical in the context of the identified need.

Point raised by ARCMesh	ElectraNet response
Why has ElectraNet not included private developers of an interconnector solution in the RIT-T process?	Early in the consultation process, as part of the PSCR, we received submissions from private enterprises, including a submission from the owners of Murraylink. That submission presented information and ideas for a new interconnector between SA and Victoria and, as a result, ElectraNet has included and modelled that option in the PADR. We also considered an interconnector option between SA and Queensland (Option B), which has been informed by ARCMesh's submissions and subsequent discussions. We have taken into account all the information received during the consultation process in developing credible options for this RIT T.

Appendix H Comparison of HVAC and HVDC transmission systems

The SAET RIT-T has considered both HVAC and HVDC technologies. The following table describes the general advantages and disadvantages of both transmission technologies in relation to the key aspects considered in developing the solution options considered.

Table 16 – Comparison of HVAC and HVDC transmission systems

Aspect	HVAC	HVDC	SAET RIT-T context
Transmission Distance	HVAC substation costs are relatively lower but the equivalent HVAC lines are more expensive than HVDC lines.	HVDC converter station costs are relatively expensive, but line costs are lower, therefore a breakeven point is reached indicatively around 700 km where HVDC options start to become lower in cost.	When tapping of the HVDC line is intended to capture additional benefits (e.g. by connecting REZ generation), the breakeven distance becomes longer because of the high cost of additional HVDC converter stations (see later).
Transmission Losses	HVAC typically has higher transmission losses compared to the HVDC equivalent.	HVDC line losses are lower but the converter (depending on converter type; e.g. VSC or LCC) also adds to losses. Losses for VSC converters can be substantial. However, overall HVDC typically has lower losses.	
Power Controllability	HVAC options need impedance or angle correcting methods like series compensation or Phase Shifting Transformers to achieve controllability of power flows.	HVDC options have better controllability of power flows across the link.	
Tapping into transmission lines	HVAC options have the significant advantage of a relatively low cost for tapping into the line to create a switching station or multiple switching stations to connect renewable generation along the way.	Few Multi-terminal HVDC systems have been implemented relatively recently to tap into a HVDC line. However, there are limited numbers of multi-terminal systems built around the world, with some major vendors not having delivered any around the world The cost of additional converter stations is very expensive compared to the HVAC alternative.	All options in the RIT-T are able to capture benefits from connecting REZ generation. Therefore, the ability to implement multiple taps on the transmission system at low cost is crucial to capture this benefit.

Aspect	HVAC	HVDC	SAET RIT-T context
Protection of tapped transmission systems	Isolation of each element is relatively easy with HVAC circuit breakers and standard substation configurations.	Isolation of part of a multi-terminal system is complex and expensive. While vendors have tested DC circuit breakers, they are not widely used commercially. The more standard lower cost protection systems shut down the entire HVDC system all at once, which may have a significant impact on reliability and security.	This is a critical issue with multi-terminal HVDC systems.
Technology Maturity	HVAC systems are mature and are built at different transmission voltages around the world.	While HVDC point-to-point technology is mature, the HVDC VSC based multi-terminal technology is not very mature and there are very limited applications around the world.	The maturity risk with HVDC multi-terminal links is a cause for concern in relation to timely delivery of the project.
Inertia	Inertia is a global concept in HVAC systems and is inherently available from across the entire power system.	HVDC systems can provide Fast Frequency Response (FFR) which can be equated to synthetic inertia in correcting frequency deviations, but capacity needs to be reserved to make this available during frequency deviation events, and the required energy has to be available at the sending end.	HVAC options have an advantage in providing inertia and there is no reserved capacity (or headroom) required to provide the inertia.
System Strength	System strength is provided across HVAC systems and is dependent on the impedance behind the sources that provide fault currents.	HVDC VSC technology can provide fault levels to the rating of the HVDC system. This depends on the pre-event MW transfer and also the distance of the fault from the HVDC converter station. For additional system strength the installation has to be over-designed to a higher rating than would otherwise be required with additional cost implications.	
Frequency Control	Frequency control in HVAC systems is provided by sources offering frequency control across the system.	HVDC systems can provide enhanced frequency control, but still rely on power transfer from sources in one region to another.	If SA stays connected to the NEM, even after loss of either interconnector, frequency control for HVAC options is derived from the NEM.

Aspect	HVAC	HVDC	SAET RIT-T context
Voltage Control	For a long transmission system, additional switching stations and static and dynamic reactive plant is required for voltage control and transient stability.	For HVDC VSC systems, four quadrant reactive power capability is available and no additional reactive plant is required.	The HVDC options cost for voltage control is a lot lower than for HVAC options, as no additional reactive plant is required.

Appendix I Breakdown of interconnector option costs

The table below provides a high-level breakdown of key components of network options in South Australia and the adjacent jurisdiction.

More information on the cost estimates of the interconnector options considered is available in the Cost Estimate Report that is published alongside this PACR.

Table 17 – High level cost breakdown of network options, costs in $m 2018-19

Option	Item	SA	QLD	NSW	VIC	TOTAL
B 400 kV HVDC from northern SA to Qld	Transmission lines	230	740			970
	Converter substations, including transformers	300	570			870
	Other costs, including reactive plant, SPS and delivery costs	60	80			140
	Total Cost	**580**	**1,400** [305]			**1,980**
C.3 330 kV line from Robertstown SA to Wagga Wagga in NSW, via Buronga, plus Buronga to Red Cliffs 220 kV	Transmission lines	230		710		940
	Substations, including transformers	90		210		300
	Other costs, including reactive plant, SPS and delivery cost	60		230		290
	Total Cost	**380**		**1,150** [306]		**1,530**
C.3ii 330 kV line from Robertstown SA to Wagga Wagga in NSW, via Buronga, Red Cliffs, Kerang and Darlington Point	Transmission Lines	230		820		1,050
	Substations, including transformers	90		260		350
	Other costs, including reactive plant, SPS and delivery costs	60		270		330
	Total Cost	**380**		**1,350** [307]		**1,730**
C.3iii 400 kV HVDC line from Robertstown SA to Darlington Point via Buronga; HVAC line from Darlington Point to Wagga Wagga, plus Buronga to Red Cliffs 220 kV	Transmission lines	140		480		620
	Substations, including transformers	290		600		890
	Other costs, including reactive plant, SPS and delivery costs	40		90		130
	Total Cost	**470**		**1,170** [308]		**1,640**

[305] The cost of construction through NSW is included in the QLD cost

[306] The cost of construction through Victoria is included in the NSW cost

[307] The cost of construction through Victoria is included in the NSW cost

[308] The cost of construction through Victoria is included in the NSW cost

Option	Item	SA	QLD	NSW	VIC	TOTAL
D 275 kV line from central SA to Victoria	Transmission lines	260			210	470
	Substations, including transformers	30			90	120
	Other costs, including reactive plant, SPS and delivery costs	110			150	260
	Network Hardening Costs	150			150	300
	Total Cost	550			600	1,150

The table below provides a breakdown of the various transmission line route lengths by jurisdiction.

Table 18 –Breakdown of interconnector option line lengths (km)

Option	SA	QLD	NSW	VIC	TOTAL
B	350	1,100[309]			1,450
C.3	210		706[310]		916
C.3ii	210		806[311]		1016
C.3iii	210		706[312]		916
D	270			240	510

309 Includes transmission line section through northern NSW

310 Includes Buronga - Redcliff section

311 Includes Buronga - Redcliff and built sections in Victoria

312 Includes Buronga - Redcliff section

Appendix J Supplementary information to the PACR

The following supplementary reports and information support this PACR.

Supplementary Reports

1. Market Modelling Methodology Report
2. SA Energy Transformation RIT-T External Review (Oakley Greenwood)
3. Gas price forecast review (EnergyQuest)
4. Network Technical Assumptions Report
5. SAET RIT-T Consolidated Non-Interconnector Option Report (Entura 5 June 2018)
6. Investigation of Interim Arrangements Report (Entura)
7. Project note responding to PADR submissions (Entura)
8. Curnamona Province Analysis (AME Advisory)
9. Cost Estimate Report (capital cost estimates of options)
10. ElectraNet Transmission Line Cost Review (Jacobs)
11. SA-NSW Interconnection – Analysis of Impacts on Liquidity in SA (CQ Partners)
12. SA-NSW Interconnector – Updated Analysis of Potential Impact on Electricity Prices and Assessment of Broader Economic Benefits (ACIL Allen)
13. Note on selection of an assessment period for a RIT-T and the use of terminal values (HoustonKemp)

Spreadsheet Models and Information (Microsoft Excel)

14. Market Modelling and Assumptions Data Book
15. Market Modelling Result Books
16. Economic Evaluation Summary Spreadsheet and Charts
17. Incremental NPV Benefits of Red Cliffs to Buronga Line

Appendix K Compliance checklist

This section sets out a compliance checklist which demonstrates the compliance of this PACR with the requirements of clause 5.16.4(v) of the NER version 118.

Rules clause	Summary of requirements	Relevant section(s) in the PACR
5.16.4(v)	The project assessment conclusions report must include:	-
	(1) the matters detailed in the project assessment draft report as required under paragraph (k)	See below.
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought	4, Appendix C, Appendix F & Appendix G
5.16.4(k)	The project assessment draft report must include:	-
	(1) a description of each credible option assessed;	5
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	PADR[313]
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	4 & 8
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	6 & 7
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	Appendix D
	(6) the identification of any class of market benefit estimated to arise outside the *region* of the *Transmission Network Service Provider* affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	6, 7 & 8
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	8
	(8) the identification of the proposed preferred option;	9
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a *material inter-network impact* and if the *Transmission Network Service Provider* affected by the RIT-T project has received an *augmentation technical report*, that report; and (iv) a statement and the accompanying detailed analysis that the preferred option satisfies the *regulatory investment test for transmission*.	9

313 This report does not repeat the discussion of submissions to the earlier PSCR, which was presented in the earlier PADR.

ElectraNet