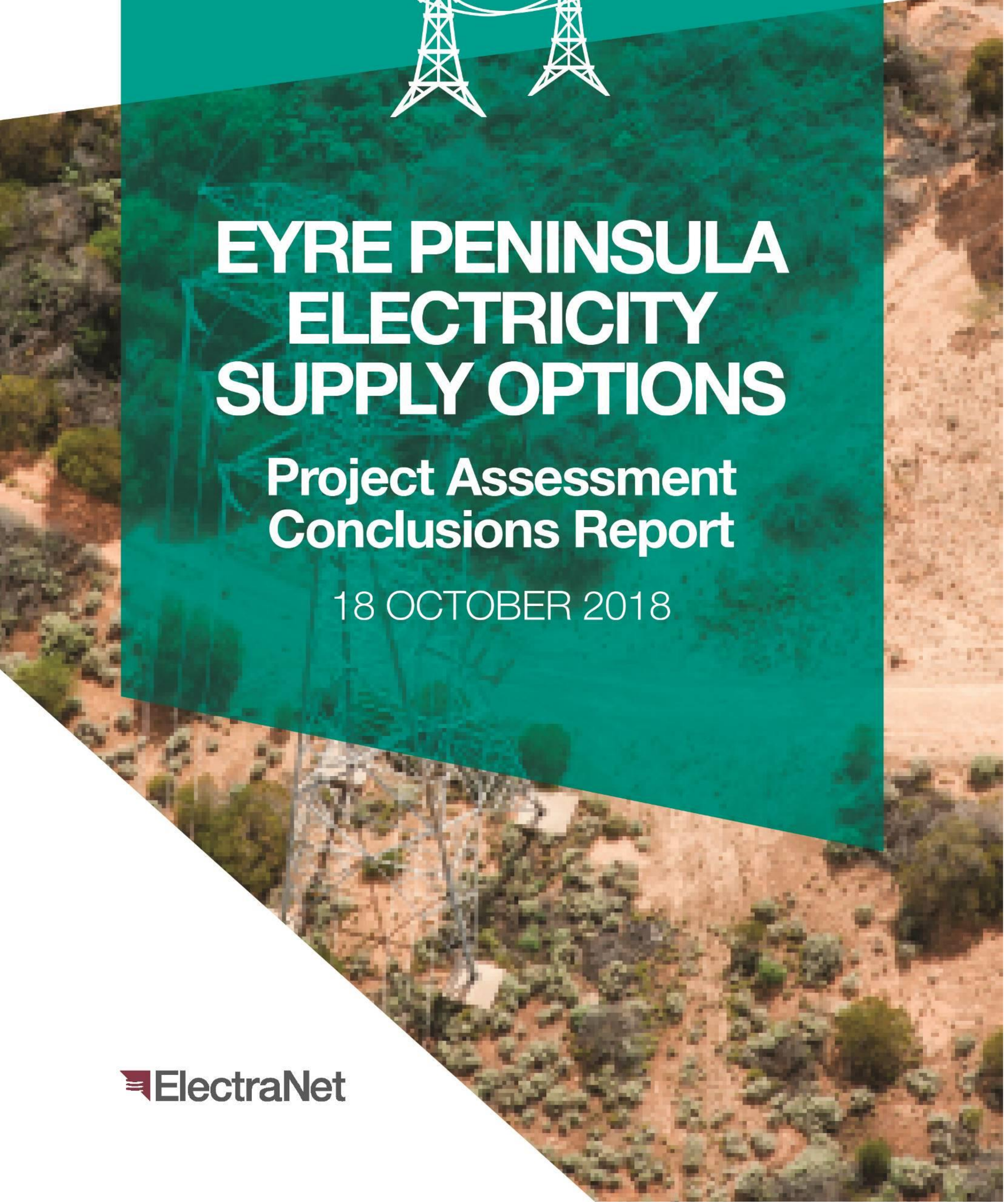
EYRE PENINSULA ELECTRICITY SUPPLY OPTIONS

Project Assessment Conclusions Report

18 OCTOBER 2018



ElectraNet

Executive Summary

ElectraNet has explored options for providing a reliable electricity supply to the Eyre Peninsula most efficiently in the future, including 'future proofing' to accommodate potential mining and renewable energy developments.

The existing single-circuit 132 kV line serving the Eyre Peninsula has been in service since 1967 and several sections now require major replacement works. In April 2018, the Australian Energy Regulator (AER) accepted our revenue proposal that included capital expenditure of about $80 million for these replacement works, and ongoing network support to provide backup supply to Port Lincoln.[1] The AER's acceptance of our revenue proposal noted that this RIT-T investigation was on-going, and included a contingent project that would allow the determination to be varied if a more efficient option was identified.

This Regulatory Investment Test for Transmission (RIT-T)[2] investigates whether there are more efficient supply options, including building new transmission lines. It also considers the benefits of 'future proofing' the new transmission line options to provide flexibility for upgrading the network to operate at a higher capacity if needed in the future.

This Project Assessment Conclusions Report (PACR) is the final step in the RIT-T process and follows the Project Assessment Draft Report (PADR), released in November 2017.

Overview

We have found that the most efficient way to provide a reliable supply to the Eyre Peninsula is:

- 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
- a new 132 kV double-circuit line from Yadnarie to Port Lincoln

This new supply arrangement is a lower cost and more flexible solution compared to that identified in the PADR, that:

- increases reliability of electricity supply to homes and businesses on the Eyre Peninsula, reducing the frequency of outages
- removes current network constraints, allowing the market to benefit from more low-cost energy from existing wind farms on the Eyre Peninsula
- provides greater opportunities for new demand and renewable energy developments on the Eyre Peninsula compared to the current supply arrangement
- includes 'future proofing' for cost-effective expansion of network capacity when needed in the future to accommodate potential larger mining developments and renewable energy investment on the Eyre Peninsula.

The cost of the new transmission line is fully offset by avoiding the cost of replacement works on the existing line and ongoing network support costs of $8 to $9m per year, resulting in a negligible price impact for the average residential customer in South Australia.

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1 AER, *ElectraNet Transmission Determination 2018 to 2023*, Final Decision, Attachment 6 – Capital Expenditure, April 2018, pp, 11-15.

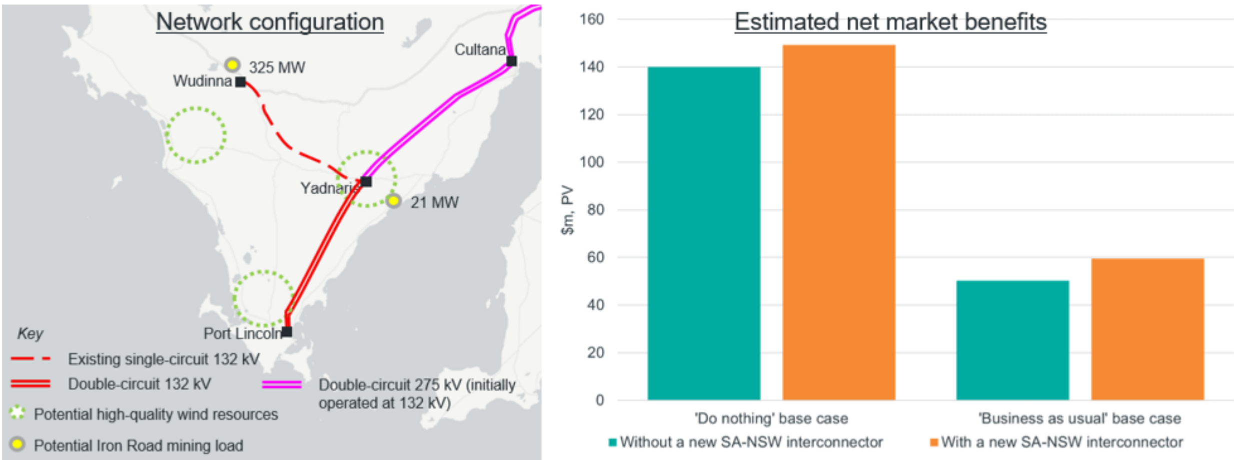
2 The Regulatory Investment Test for Transmission (RIT-T) is the economic cost benefit test that is overseen by the AER and applies to all major network investments in the National Electricity Market.

The preferred option is 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 in the future, with a new 132 kV double-circuit line from Yadnarie to Port Lincoln

We have investigated five broad options for supplying the Eyre Peninsula, together with variants of these options. These range from maintaining equivalent capacity on the Eyre Peninsula as currently (i.e., a single-circuit 132 kV line coupled with network support at Port Lincoln), through to upgrading the entire network to 275 kV, with two completely divergent network paths (including via Wudinna).

The RIT-T assessment shows that options which involve building a new double-circuit transmission line from Cultana to Port Lincoln, via Yadnarie, are expected to deliver the greatest net market benefits. Of these options, the preferred option[3] (Figure E.1) involves building a 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 at a later date (including during the initial construction phase) if prospective mining developments on the Eyre Peninsula become committed, with a new 132 kV double-circuit line from Yadnarie to Port Lincoln.

Figure E.1 – Preferred option for the Eyre Peninsula, 'Option 4D'[4]



Note: The 'business as usual' base case involves reconductoring sections of the existing transmission line and establishing a new backup generation network support arrangement at Port Lincoln, while the 'do nothing' base case reflects reliance on increasing reactive maintenance and network support, with no reconductoring of the existing line.

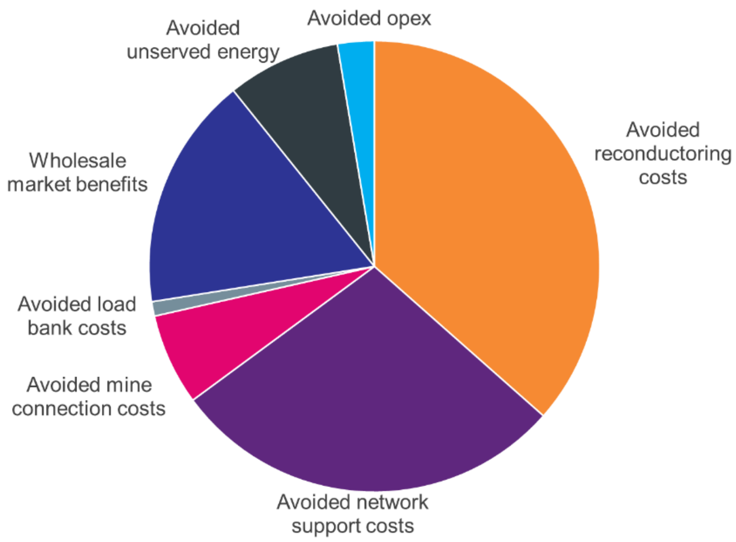
The benefits of the preferred option (Figure E.2) against the business as usual base case primarily comprise:

- avoided future costs of reconductoring the existing lines
- avoided costs associated with future network support contracts (which are no longer needed)
- wholesale market benefits (principally due to increasing output from existing wind farms)
- reductions in unserved energy
- avoided costs of future mining connections (adjusted for the probability of mining load emerging in the future).

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

[4] The approximate $90 million of net benefit difference between the two different base cases reflects the net benefits of reconductoring sections of the existing transmission line and establishing a new backup generation network support arrangement at Port Lincoln estimated as part of ElectraNet's 2018-23 Revenue Proposal, adjusted for inflation.

Figure E.2 – Breakdown of benefits for the preferred option, 'Option 4D', with a new SA-NSW interconnector



Details of the preferred option include:

- An estimated capital cost of $240 million, which is approximately $160 million more than reconductoring sections of the existing transmission line[5]
- Removal of the need for backup network support, saving direct ongoing operating costs of around $8 to $9 million per year
- Delivery of net market benefits of around $150 million over 20 years (in PV terms) relative to a 'do nothing' base case with a new SA-NSW interconnector in-place, or $140 million without a new interconnector
- Net benefits that are approximately $60 million and $50 million more than reconductoring the existing line and renewing a network support contract at Port Lincoln with and without the interconnector, respectively
- The cost of the new transmission line is offset by saving customers the cost of replacement works on the existing line and ongoing network support costs of $8 to $9 million per year, resulting in a neutral impact on the transmission component of the annual electricity bill for the average residential customer in South Australia relative to the reconductoring option (business as usual base case)
- If a new mining load or other significant load connects in future, the further upgrade works to enable operation of the Cultana to Yadnarie line at 275 kV would be funded by customers generally. However, depending on its actual size, the new significant load would bear a significant portion of both locational and wider components of transmission charges, expected to result in an overall reduction of transmission charges to other customers.

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[5] The $160 million has been calculated as the capital cost of the preferred option ($240 million) less the capital cost of reconductoring sections of the existing line in this regulatory control period ($80 million).

The preferred option has changed since the PADR, requiring lower up-front costs

The preferred option in the PADR was a ‘set and forget’ option comprising a double-circuit 275 kV line between Cultana and Yadnarie, and a double-circuit 132 kV line between Yadnarie and Port Lincoln (‘Option 4B’).

The preferred option in this PACR is a more flexible variant of this earlier option involving lower up-front cost, under which the section between Cultana and Yadnarie would be built to 275 kV but operated at 132 kV until additional capacity is needed, e.g. to accommodate the commitment of new mining or other load on the Eyre Peninsula.

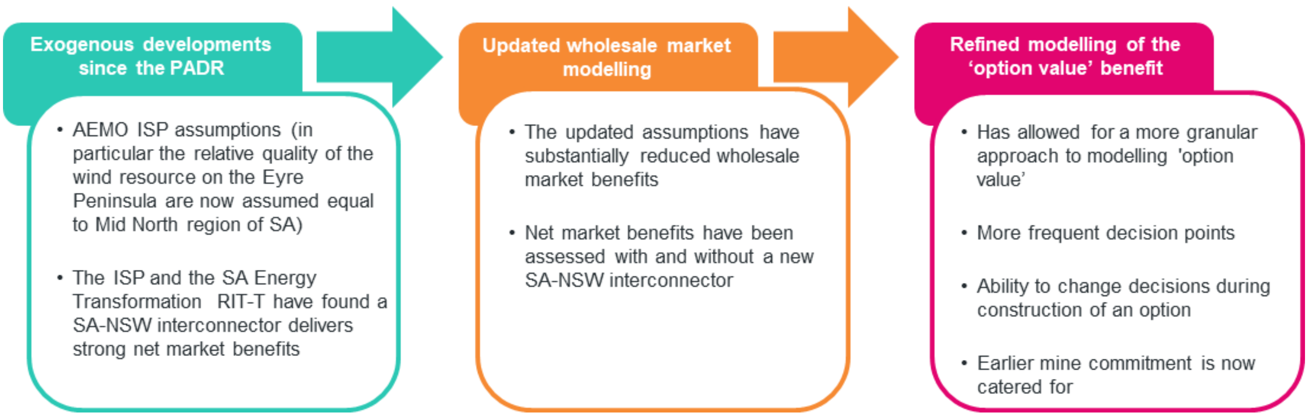
In the event such commitment occurs prior to completion of construction, then this option would be operated at 275 kV from the start as the preferred option, and would therefore be the same as Option 4B. However, if there is no commitment of mining or other load, then the costs associated with the substation components of Option 4B would be avoided until such time as required to accommodate mining or other development, thus lowering the upfront costs to customers.

Key modelling assumptions have been updated to align with AEMO’s Integrated System Plan

We have aligned the underlying wholesale market modelling assumptions with the assumptions used for the inaugural Integrated System Plan (ISP) released by the Australian Energy Market Operator (AEMO)[6].

The PADR highlighted that wholesale market benefits were largely driven by the assumption of a relatively higher quality of wind resource on the Eyre Peninsula, and that a reduction in the assumed differential would have a corresponding impact on reducing the market benefits in the RIT-T assessment.

Figure E.3 – Developments since the PADR



Since the publication of the PADR, AEMO has undertaken detailed investigations into various renewable resources around Australia. In particular, the ISP assumes that there is no material difference between the quality of the wind resource on the Eyre Peninsula and in the Mid North region of South Australia.

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6 AEMO, Integrated System Plan, July 2018.

We have updated the RIT-T wholesale market modelling to align with this assumption, even though a recent assessment we commissioned from Aurecon continues to find that there are high quality wind resources on the Eyre Peninsula that could potentially be developed in preference to resources in the Mid North.

Updating this assumption has resulted in a reduction in the wholesale market benefits estimated for the options under this RIT-T compared to the PADR, with wholesale market benefits now primarily driven by the impact of the various options on relieving constraints on the operation of the existing windfarms on the Eyre Peninsula.

The ISP has assumed in its base case that replacement of the existing lines on the Eyre Peninsula with a double circuit 132 kV line would proceed. The ISP includes a high level consideration of a potential upgrade of the network to a double circuit 275 kV line to Yadnarie to connect additional generation and concludes that this would be required in the late 2030s under its Neutral case assumptions. However, the ISP does not explicitly consider the implications of potential mining loads on the Eyre Peninsula or the option value arising from initially constructing higher rated lines.

We have refined our approach to 'option value' assessment

The PADR analysis made a number of simplifying assumptions regarding the timing of the emergence of mining loads in order to accommodate the 'option value' analysis within the broader cost benefit and wholesale market modelling framework used for the RIT-T assessment.

We have now applied a more granular approach to modelling the 'option value' associated with options that have the flexibility to stage the investment and respond to changes in external events.

In particular, we have made three key refinements to the option value modelling framework (Figure E.4) to reflect a more realistic set of responses to new information as and when it becomes available.

The refined option value modelling continues to feed into the updated wholesale market modelling to derive the overall cost benefit results.

Figure E.4 – How the modelling of 'option value' has been refined in the PACR assessment

Modelling Parameter	Simplifying assumption made in the PADR assessment	Refined assumption used in the PACR assumption
How often can decisions about upgrading voltage from 132 kV to 275 kV be made	Three decision points regarding upgrading over the 20-year period– an initial decision in 2018 and two further decisions at five-year intervals	Annually
First year a mine could make a binding connection agreement	2023	2019
Interaction between constructing an option and mines committing	Not previously accommodated for	Incorporated flexibility for the construction plan to change during the construction period to accommodate higher capacity substations, where mining load seeks connection *during* the construction period

Submissions to the PADR led to consideration of three new options

We received 12 submissions on the PADR from a range of interested parties. Submissions helped us shape and consider three new options or option variants.

As a result, our assessment now includes two new lower capacity options that involve reconductoring sections of the existing line and building a new 132 kV line on a separate easement – one via Yadnarie and another via Wudinna (Options 2B and 3B, respectively).

We also further considered a 500 kV double-circuit option, including the potential to go via the West Coast of the Eyre Peninsula. However, our detailed costing of this option found that it would involve capital costs in excess of $2 billion – more than three times the most expensive credible option considered – without providing commensurate additional market benefits. This finding, combined with the revised assumptions regarding the relative quality of wind resources on the Eyre Peninsula, led to the assessment of this option being discontinued.

A range of other queries were raised in submissions that have been addressed in this PACR.[7] Engie raised a number of detailed questions regarding the wholesale market modelling, which have led to revisions to the modelling and this is addressed in detail in Appendix H to this PACR.

In addition to the two new lower capacity options (Options 2B and 3B), we have assessed the same broad options for supplying the Eyre Peninsula as in the PADR, which reflect a wide variety of different network capacities and routes. These options range from:

- maintaining equivalent capacity on the Eyre Peninsula to that currently available, i.e., a single-circuit 132 kV line coupled with network support at Port Lincoln; through to
- upgrading the entire network to 275 kV, with two completely divergent network paths from Cultana to Port Lincoln in order to provide greater supply resilience.

Table 1 summarises each of the options we have assessed in this PACR.

Table 1 – Summary of the credible options assessed

Option	Pt Lincoln network support	Single or double-circuit	Voltage	Estimated capital cost(s)[8, 9]
Options involving transmission lines from Cultana to Port Lincoln via Yadnarie				
1 ('base case')	Yes	Single (retain current line)	132 kV	$80 million (reconductor initial sections) $90 million (reconductor remaining sections in 2033) $25 million (future replacement of Yadnarie substation in 2037)
2	No	Double	132 kV	$225 million $20 million (future replacement of Yadnarie substation in 2037)

[7] Key topics raised by parties in submissions include the: use of least-cost modelling for RIT-T planning purposes; credibility of larger and smaller capacity options; assumed uptake of wind generation; constraints on existing wind farms; mining developments; and current network support arrangement at Port Lincoln.

[8] The scope and capital cost estimates for each of the options has been refined and updated since the PADR. Appendix I summarises the extent of these revisions and provides a further breakdown and timing of the costs.

[9] All options also incur $2.9 million cost of installing a 5 MW load bank at Port Lincoln in 2019, with option 1 requiring additional 5 MW load banks at a cost of $2.9 million in each of 2025, 2030 and 2035.

Option	Pt Lincoln network support	Single or double-circuit	Voltage	Estimated capital cost(s)[8, 9]
2B	No	Single	132 kV	$215 million $25 million (reconductor remaining sections in 2033) $20 million (future replacement of Yadnarie substation in 2037)
4A	No	Double	275 kV	$330 million
4B	No	Double	275 kV (Cultana to Yadnarie) 132 kV (Yadnarie to Port Lincoln)	$275 million
4C (flexible option)	No	Double	132 kV, with ability to be energised at 275 kV in future	$250 million *Plus* $40 million if the Cultana to Yadnarie line is upgraded to 275 kV operation *Or, plus* $80 million if all lines are upgraded to 275 kV operation $20 million (if needed for future replacement of Yadnarie substation in 2037)
4D (flexible option)	No	Double	132 kV, with ability to energise Cultana to Yadnarie section at 275 kV in future	$240 million *Plus* $40 million if the Cultana to Yadnarie line is upgraded to 275 kV $20 million (if needed for future replacement of Yadnarie substation in 2037)
Options involving transmission lines from Cultana to Port Lincoln via Yadnarie and Wudinna				
3	No	Single	132 kV	$405 million $25 million (replacement of Yadnarie substation in 2037)
3B	No	Single	132 kV	$290 million $25 million (reconductor remaining sections in 2033) $25 million (future replacement of Yadnarie substation in 2037)
5A	No	Single	275 kV	$560 million
5B	No	Single	275 kV (Cultana to Wudinna) and 132 kV elsewhere	$450 million $25 million (future replacement of Yadnarie substation in 2037)
5C (flexible option)	No	Single	132 kV, with ability to energise all sections at 275 kV in future	$455 million *Plus* $25 million if the Cultana to Wudinna line is upgraded to 275 kV operation *Or, plus* $65 million if the Cultana to Wudinna line AND the Cultana to Yadnarie lines are upgraded to 275 kV operation *Or, plus* $110 million if all lines are upgraded to 275 kV operation $25 million (if needed for future replacement of Yadnarie substation in 2037)

Three options have been specifically designed to be flexible and allow the ‘option’ of upgrading network capacity in the future, if a certain ‘trigger’ occurs (Options 4C, 4D and 5C). This allows us to consider the benefit of spending more upfront to provide flexibility for upgrading the network to 275 kV at a lower cost later, if required.

Options involving new double-circuit lines from Cultana to Port Lincoln via Yadnarie are the top-ranked options

The PACR assessment finds that new double-circuit lines from Cultana to Port Lincoln via Yadnarie provide the greatest net market benefit. The benefits of all options increase if a new interconnector between South Australia and New South Wales is assumed (Figure E.5),[10] on account of additional output from existing Eyre Peninsula wind farms that can displace more expensive generation elsewhere in the NEM (Figure E.6 and Figure E.7).

The key findings of our updated assessment are that:

- All the options considered provide market benefits in terms of increased reliability, and therefore decreased unserved energy, for customers on the Eyre Peninsula – this is estimated to provide a benefit to residents of the Eyre Peninsula of approximately $1 million/year (in PV terms) under the preferred option (Option 4D)
- All options provide a substantial benefit in avoiding network support costs associated with maintaining the required South Australian Electricity Transmission Code (ETC)[11] reliability standard at Port Lincoln – this avoided cost is, however, substantially the same for all credible options, relative to the 'business as usual' base case of line reconductoring (Option 1) and so does not affect the ranking of the options
- There are expected to be lower transmission costs associated with connecting new mining load to the electricity network for options that result in all, or part, of the Eyre Peninsula being operated at 275 kV capacity
- There are negligible benefits stemming from any impact on the wholesale electricity market by facilitating *new* wind generation locating on the Eyre Peninsula – this is a key change from the PADR and is due to the updated assessment of the relative wind resource quality on the Eyre Peninsula undertaken by AEMO as part of the ISP
- The estimated benefits of all options increase if a new interconnector between South Australia and New South Wales is assumed (consistent with the findings of the ISP and the South Australian Energy Transformation RIT-T currently being undertaken by ElectraNet[12]) – while Option 4D is estimated to deliver around $2 million more net market benefits than Option 2 (ie, the second ranked option, being a non-upgradeable line) under the assumption that no new interconnector is built, this rises to $7 million if a new interconnector is assumed to be built.

While wholesale market benefits have reduced from the PADR owing to changes to wind capacity factor assumptions and the resulting reduction in projected new wind generation locating on the Eyre Peninsula, the assessment still finds a material benefit associated with relieving the constraints on and reducing losses for existing wind farms on the Eyre Peninsula.

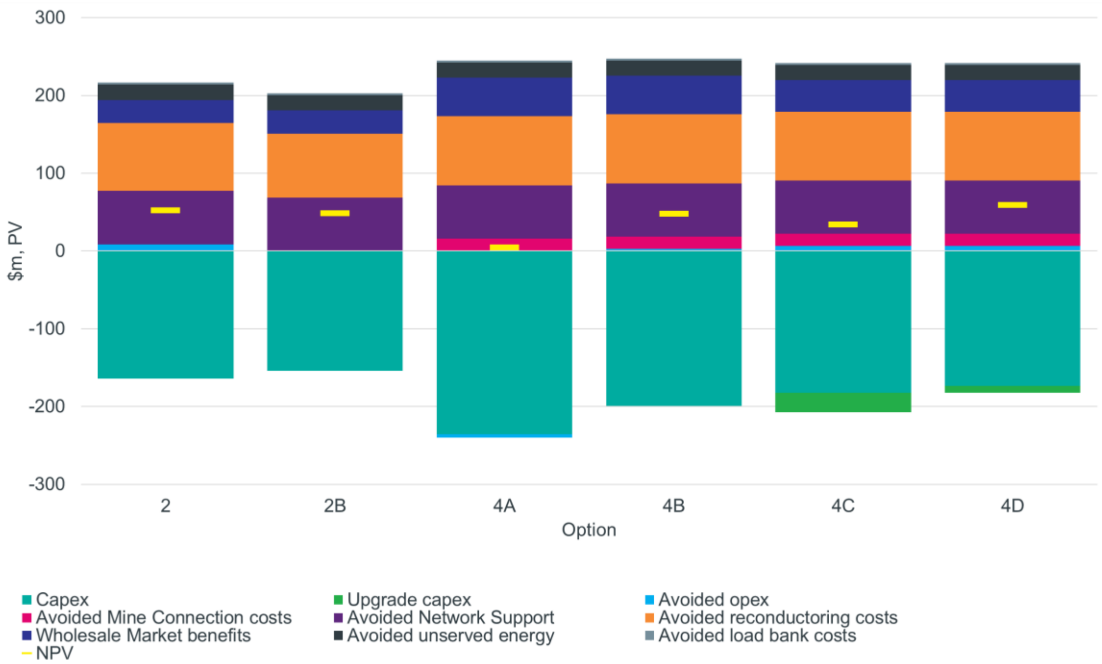
[10] Consistent with the AEMO ISP and the coincident South Australian Energy Transformation RIT-T.

[11] The Electricity Transmission Code is made by the Essential Services Commission of South Australia (ESCOSA) and specifies required reliability standards at transmission network connection points, including on the Eyre Peninsula.

[12] Available at https://www.electranet.com.au/projects/south-australian-energy-transformation/.

Figure E.5 – Summary of estimated net market benefits for credible options going via Yadnarie[13] assessed under the 'core'[14] set of assumptions

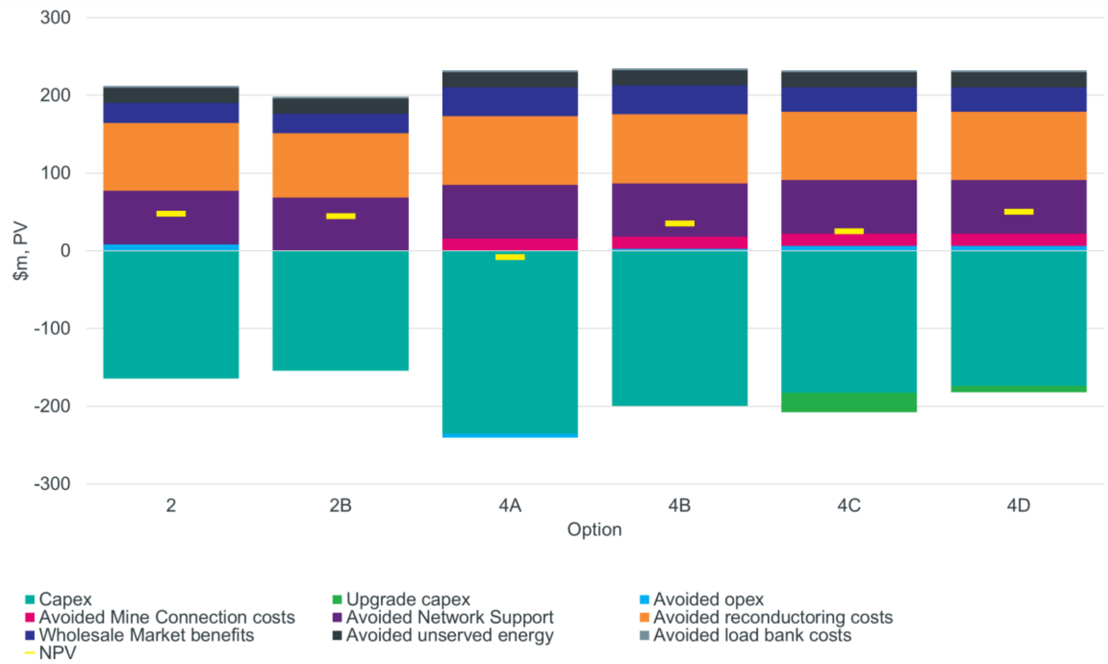
Figure E.6 – Breakdown of estimated net market benefits for credible options going via Yadnarie assessed under the 'core' set of assumptions – with a new SA-NSW interconnector assumed



13 This figure, Figure E.6 and Figure E.7 show only the estimated net market benefits for the credible options that go via Yadnarie. The options involving a new line going via Wudinna have significantly negative net market benefits. The results for the Wudinna options are presented in detail in the body of this PACR.

14 The 'core' set of assumptions reflect ElectraNet's weighted view regarding key underlying assumptions likely to affect the magnitude of net market benefits estimated for each option. These core assumptions have been stress-tested through various sensitivity tests to ensure the robustness of the overall results. The 'core' set of assumptions also assume a 'business as usual' base case, where the existing line is re-conductored and network support is continued to be provided at Port Lincoln to meet ETC requirements.

Figure E.7 – Breakdown of estimated net market benefits for credible options going via Yadnarie assessed under the 'core' set of assumptions – no new SA-NSW interconnector assumed



Other findings include:

- Option 4D is the preferred option as it introduces flexibility and saves costs upfront by operating the Cultana to Yadnarie section at 132 kV until new mining or other load increase triggers conversion to 275 kV
- The additional cost of going via Wudinna (Options 3 and 3B and Options 5A-5C) is found to be greater than the additional benefits delivered
- The new variant of Option 2, developed in response to submissions to the PADR, that involves reconductoring sections of the existing line (Option 2B) is found to provide slightly reduced positive net market benefits than Option 2, while the additional cost of such an option going via Wudinna (Option 3B) results in substantial negative net market benefits
- Option 4B (with no flexibility) has higher costs than Option 4D (due to the Cultana to Yadnarie route being built and operated at 275 kV from the start), and so provides less net market benefits
- While Option 4C would still provide positive net market benefits, the cost of also providing flexibility to later upgrade the Cultana to Port Lincoln section to 275 kV was not found to be justified by the potential additional benefits.

The preferred option is robust to the assumed likelihood of new mining developments

The results are robust to the underlying assumptions regarding the likelihood that new mining developments will come to fruition on the Eyre Peninsula over the next 20 years.

We have sought independent advice from mining advisory firm AME Research on the likelihood of the various potential mining developments on the Eyre Peninsula progressing (Appendix L). AME

is of the view that there is a greater than 50% probability of Iron Road[15] coming online over the next 15 years. AME considers that the other potential mining loads on the Eyre Peninsula are not expected to come online over this period (and has effectively assumed they have a zero per cent probability, which has been reflected in the core modelling results in this PACR).

The magnitude of the estimated net market benefits is found to be sensitive to these underlying assumed likelihoods. While Option 4D is the top-ranked option under the core assumptions, it becomes even more preferred if other mining developments (i.e. other than Iron Road) are given a positive probability of developing over the assessment period. As an example, keeping all 'core' assumptions constant but increasing the likelihood that the other mining loads will develop to 1 per cent per year, increases the estimated net market benefits associated with Option 4D from approximately $59 million to $67 million if a new SA-NSW interconnector is assumed to be built, and from $50 million to $59 million if no new SA-NSW interconnector is assumed to be built.

We therefore consider that there is considerable potential upside to the core estimate of approximately $50-$59 million in net market benefits for Option 4D if any other mining or other loads do in fact develop on the Eyre Peninsula.

The assessment finds that Option 4D remains the preferred option even if the probability that the Iron Road mines will develop is reduced to 4.4 per cent per year[16] in the case where no new SA-NSW interconnector is assumed to be built (this assessment keeps the likelihood of the other mining developments at 0 per cent).

This is substantially below the AME assessment of 5.8 per cent per year.[17] Moreover, if a new interconnector is built, the likelihood that Iron Road would develop has to fall to 2.5 per cent per year[18] for Option 4D to no longer be preferred.

In addition, the assessment finds that, even if Iron Road is assumed to not develop over the assessment period (and there are no other developments), Option 4D is still estimated to have positive net market benefits. If a new interconnector is assumed to be built, under these assumptions Option 4D has an estimated net market benefit of $43 million, ranked marginally behind Option 2 and 2B at $50 million and $47 million, respectively. Without the interconnector, under these assumptions Option 4D has estimated net market benefits of $36 million, and is ranked behind Options 2 and 2B (which have higher estimated net market benefits of $45 million and $41 million, respectively).

These findings demonstrate that the preferred option is robust to the assumed likelihood of new mining developments or other demand increases in the future.

Option 4D relieves constraints on existing wind farms and creates opportunities for new renewable development on the Eyre Peninsula

A new double-circuit line from Cultana to Port Lincoln, via Yadnarie, not only relieves constraints on existing wind farms on the Eyre Peninsula, but also provides opportunities for new renewable energy developments on the Eyre Peninsula.

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[15] Throughout this report where we refer to the 'Iron Road' mining development, we are referring to Iron Road's Central Eyre Iron Project (CEIP).

[16] Equivalent to a 49% likelihood of Iron Road coming online over the next 15 years.

[17] Assuming a 4.4 per cent annual likelihood for Iron Road under the 'core' assumptions, and a zero probability for other developments, results in Option 4D and Option 2 having equal estimated net market benefits (of $47.5 million).

[18] Equivalent to a 32% likelihood of Iron Road coming online over the next 15 years.

The double-circuit lines between Cultana to Yadnarie would be able to accommodate approximately 500 MW of additional renewable generation if operated at 132 kV (and a further 500 MW, or 1,000 MW in total, if upgraded to 275 kV), while the 132 kV lines between Yadnarie and Port Lincoln would be capable of accepting about 350 MW of any such developments.

This finding is consistent with the ISP, which found that approximately 450 MW of solar generation is expected to locate on Eyre Peninsula in the late 2030s under a number of its future scenarios.

In addition, while the wholesale market modelling forecasts that minimal new wind generation will locate on the Eyre Peninsula over the assessment period, this may not ultimately be the case once the new lines are constructed. In particular, the modelling in this PACR adopts the ISP assumption that the wind resource quality on the Eyre Peninsula is approximately equal to that of the neighbouring Mid North region of South Australia.

However, prior to adopting the ISP assumptions, ElectraNet commissioned Aurecon to assess the quality and quantity of wind generation that could connect on the Eyre Peninsula. Aurecon concluded that the Eyre Peninsula is a marginally superior location on account of both the ability to build higher wind turbine towers on the Eyre Peninsula as well as a number of practical limitations that may limit new renewable generation in the Mid North region.

These additional benefits have not been included in the RIT-T assessment and would further add to the net benefits of the preferred Option 4D.

The preferred option also delivers additional benefits that are beyond the scope of the RIT-T framework

While the RIT-T is a rigorous economic cost benefit test to determine the merits of options to upgrade the transmission network, it is limited to the impact of investment within the electricity sector; that is, the costs and benefits which accrue to electricity generators, distributors, transmission businesses and electricity consumers. However, it can also be expected that there will be broader benefits of the preferred option to the South Australian community and economy.

Assessment of these broader benefits is beyond the scope of the RIT-T, but include:

- community benefits resulting from additional jobs in the construction of the new transmission infrastructure; and
- flow on benefits of increased local economic activity in industries that are facilitated by the investment; for example, for local commerce, agriculture, industry and mining operations and renewable energy developments in the region that are assisted by improved network capability or increased confidence about availability and reliability of supply.

The preferred option can be in place by the end of 2021

The preferred option can be constructed by the end of 2021, subject to obtaining necessary statutory approvals. In the event that sufficient mining load commits on the Eyre Peninsula before this date, then the preferred option would incorporate the substation works required to enable initial operation at 275 kV. Otherwise the preferred option would be operated at 132 kV with the substation upgrades occurring only when needed to accommodate the commitment of mining loads or other developments.[19]

[19] The future incremental capital works of moving from 132 kV operation to 275 kV operation centre on substation works and are expected to take two years to complete.

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Glossary of Terms

Term	Description
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CEIP	Central Eyre Iron Project
ETC	Electricity Transmission Code
ESCOSA	Essential Services Commission of South Australia
FCAS	Frequency Control Ancillary Services
FY	Financial Year, e.g. FY2018 is 2017-18
HVDC	High-Voltage Direct Current
ISP	Integrated System Plan
MLF	Marginal Loss Factor
NEG	National Energy Guarantee
NEM	National Energy Market
NER	National Electricity Rules
NPV	Net Present Value
NTNDP	National Transmission Network Development Plan
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
PV (Costs and benefits)	Present value
PV (Solar generation)	Photovoltaic
QRET	Queensland Renewable Energy Target
RET	Renewable Energy Target
REZ	Renewable Energy Zone
RFT	Request for Tender
RIT-T	Regulatory Investment Test for Transmission
SACOME	South Australian Chamber of Mines and Energy
SAET	South Australia Energy Transformation
TNSP	Transmission Network Service Provider
USE	Unserved Energy
VCR	Value of Customer Reliability
VRET	Victoria Renewable Energy Target

1. Introduction

ElectraNet has explored electricity supply options for meeting the South Australian Electricity Transmission Code (ETC)[20] reliability standards for the Eyre Peninsula most efficiently in the future, whilst 'future proofing' the investment to accommodate potential developments in mining and renewable energy investment on the Eyre Peninsula.

This PACR represents the final step in the application of the Regulatory Investment Test for Transmission (RIT-T)[21] to network and network support options for ensuring reliable electricity supply to the Eyre Peninsula into the future. It follows the release of the Project Assessment Draft Report (PADR) in November 2017, which presented our draft view on the preferred option at the time.

The existing single 132 kV line serving the Eyre Peninsula has been in service since 1967 and several sections now require replacement based on their condition. In April this year, the Australian Energy Regulator (AER) accepted our revenue proposal that included capital expenditure of about $80 million for these replacement works, and a corresponding amount for ongoing network support to provide backup supply to Port Lincoln.

This RIT-T investigates whether there are more efficient supply options, including investing in slightly greater network capacity now to allow for the option of upgrading the network to operate at 275 kV at a later date. The AER's acceptance of our revenue proposal noted that this RIT-T investigation was on-going, and included a contingent project provision that would allow the determination to be varied if a more efficient option is identified.

A lower cost and more flexible option than that in the PADR is now preferred

The preferred option in the earlier PADR was a 'set and forget' option comprising a double-circuit 275 kV line between Cultana and Yadnarie, and a double-circuit 132 kV line between Yadnarie and Port Lincoln.

The preferred option in this PACR is a more flexible variant of this earlier option, under which the section between Cultana and Yadnarie would be built to 275 kV but operated at 132 kV until additional capacity is needed, e.g. to accommodate the commitment of new mining load on the Eyre Peninsula. This new supply arrangement is a lower cost and more flexible solution than that in the PADR, whilst providing the same categories of benefit and retaining the 'future proofing' for cost-effective expansion of network capacity when needed in the future.

The key change between the PADR and PACR that has driven this result is detailed work undertaken by AEMO, as part of its Integrated System Plan, into the relative quality of the wind energy resource on the Eyre Peninsula. In particular, the AEMO investigation concluded that it is not obviously a higher quality resource than the Mid North region of South Australia.

[20] The Electricity Transmission Code is made by the Essential Services Commission of South Australia (ESCOSA) and specifies required reliability standards at transmission network connection points, including on the Eyre Peninsula.

[21] 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.

We received 12 submissions from parties on the PADR, reflecting a range of views and interests. We have considered these submissions and responded to the issues raised in the analysis presented in this report.

1.1 Role of this report

This report:

- describes the identified need which ElectraNet is seeking to address, together with the credible options that ElectraNet considers may address this need (sections 3 and 5);
- summarises and responds to the submissions received on the PADR (section 4);
- 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 by ElectraNet in undertaking this quantification (sections 5.1, 0 and 8);
- presents the results of the Net Present Value (NPV) analysis for each credible option assessed, together with accompanying explanatory statements (section 9); and
- identifies the credible option which satisfies the RIT-T and which is therefore the preferred option for investment by ElectraNet (section 10).

Appendices to this PACR provide further information on the RIT-T process, the assumptions/methodologies underpinning this RIT-T assessment and results of the economic assessment undertaken.

1.2 Further information and next steps

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

ElectraNet now intends to commence the pre-investment activities necessary to proceed with the preferred option, including seeking a determination by the AER that the proposed investment satisfies the RIT-T, followed by seeking AER approval of this investment as a contingent project.

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

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Network Planning Manager
ElectraNet Pty Ltd
+61 8 8404 7641
consultation@electranet.com.au

2. Key developments since the PADR

There have been a number of important developments since the PADR was released that have affected key assumptions in the wholesale market modelling used in this RIT-T. The most significant, in terms of impact on this RIT-T, have been the assumptions coming out of the AEMO ISP process.

This section outlines three key changes since publication of the PADR. Sections 5.1 and 0 provide more detail on how the underlying assumptions in this PACR assessment have been affected by these changes.

2.1 Relative quality of Eyre Peninsula wind resources

ElectraNet worked closely with AEMO as it developed its first ISP, particularly in relation to assumptions and developments that relate to South Australia. The ISP provides a 'roadmap' for the transition of the energy sector, in response to a recommendation of the Finkel review.[22]

The most significant implication of the ISP for this RIT-T follows detailed investigations undertaken by AEMO and its consultants into various renewable resources around Australia. Specifically, AEMO has concluded that, while of high quality, there is no material difference between the quality of the wind resource on the Eyre Peninsula and that in the Mid North region of South Australia.

This has a material impact on the analysis in this RIT-T and marks a significant departure in assumptions from the PADR analysis, where the Eyre Peninsula was considered a superior resource based on the latest information available at that time. The PADR highlighted that wholesale market benefits from the various options were largely driven by the assumption of a relatively high quality of wind resource on the Eyre Peninsula, and that any reduction in the assumed differential would have a corresponding impact on the market benefits in the RIT-T assessment.

We have updated the wholesale market modelling for this RIT-T to align with AEMO's assumptions on the relative strength of the relevant wind resources (as well as all other material updated assumptions contained in the ISP).[23] Updating this assumption has resulted in a substantial fall in the wholesale market benefits estimated for the options under this RIT-T, with benefits now primarily driven by the impact of the various options on relieving constraints on the operation of the existing windfarms on the Eyre Peninsula, rather than relating to new wind generation. It is important to note however that, while the wholesale market modelling forecasts limited investment in new wind farms on the Eyre Peninsula over the assessment period, this may not ultimately be the case once the new lines are constructed.

Prior to receiving the ISP assumptions regarding wind quality, ElectraNet engaged Aurecon to assess the quality and quantity of wind generation that could connect on the Eyre Peninsula.

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

[23] AEMO's final wind trace assumptions were higher than its earlier assumptions, on which the market modelling in this RIT-T has been based. However, the relativities remain largely the same – see section 6.6.

Aurecon concluded that the Eyre Peninsula is a marginally superior location, compared to the Mid North region of South Australia, on account of the higher likelihood of obtaining planning approvals to build higher towers on the Eyre Peninsula as well as a number of practical limitations limiting new renewable generation in the Mid North region.

2.2 Jurisdictional renewable policies

The PADR modelling assumed that only the first auction under the Victorian Renewable Energy Auction Scheme is held in 2018 and that the auction successfully procures the full quantity of capacity contracts available; i.e. 100 MW of solar PV generation and 550 MW of technologically neutral renewable generation. Recognising the uncertainty regarding future state-based renewable energy targets, the PADR modelling did not make any assumptions regarding longer-term renewable energy targets for Victoria or other jurisdictions.

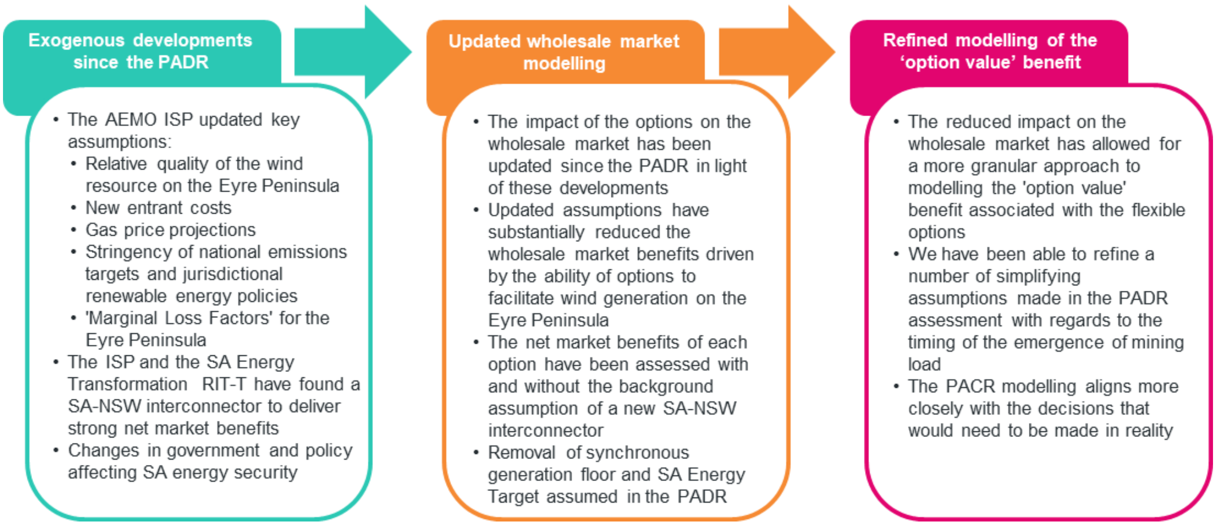
However, the ISP wholesale market assumptions reflect both the Victorian Renewable Energy Target (VRET) and the Queensland Renewable Energy Target (QRET) being put in place in full. The PACR assessment updates these assumptions to align with the ISP.

2.3 A more granular approach to estimating 'option value'

We have been able to refine the approach to option value modelling for the PACR.[24] In particular, we have made three key refinements to the option value modelling framework to reflect a more realistic set of responses to new information as and when it becomes available.

Figure 8 outlines how external developments since the PADR have led to a refined modelling of 'option value'.

Figure 8 – Developments since the PADR have led to a refined modelling of 'option value'



[24] The moderate impact of options on the wholesale market has reduced the materiality of modelling the impact of each potential permutation of the timing and quantum of mining developments on wholesale market outcomes. This has allowed for a more granular approach to modelling the 'option value' associated with options that exhibit flexibility, through the ability to stage the investment and respond to changes in external events.

3. Reliable electricity supply to the Eyre Peninsula

The identified need for this RIT-T is to explore electricity supply options for meeting ETC reliability standards at Port Lincoln most efficiently in the future – in light of the requirement to replace major transmission line components serving the lower Eyre Peninsula in the next few years, and the upcoming expiry of the network support arrangement at Port Lincoln.

The ETC transmission reliability standards are generally expressed in terms of the amount of 'redundancy' that must be built into the network to avoid supply outages. Redundancy is generally expressed in 'N-x' terms, where 'x' reflects the number of elements[25] that could fail on the network without electricity supply being lost.

The ETC specifies several different reliability standards for loads on the Eyre Peninsula, with the highest being the ETC 'Category 3' at Port Lincoln which essentially requires an 'N-1' level of reliability, which means that electricity supply still needs to be met if any one element of the network fails. With the exception of Port Lincoln, ElectraNet meets the ETC reliability requirements for all of the connection points on the lower Eyre Peninsula through transmission assets alone.

For Port Lincoln, the transmission service includes a network support arrangement that allows ElectraNet to call upon local generation services, to provide equivalent transmission line and transformer capacity in accordance with the ETC requirements. Reliability standards under the ETC are generally expressed as "equivalent" line or transformer capacity standards to allow flexibility for meeting the standards by any means or a combination of means (including network and non-network options).

Overall, meeting the ETC reliability standard at Port Lincoln, and ensuring reliable electricity supply to the entire Eyre Peninsula, forms the identified need for this RIT-T. However, the need to replace sections of the current network, and the upcoming expiry of the current network support agreement, provide the opportunity for ElectraNet to also consider the most efficient investment to make now to 'future proof' the supply arrangements to accommodate likely future developments on the Eyre Peninsula. In particular, there is the potential for future mining load and/or wind generation developments on the Eyre Peninsula.

There are several important decisions we can make now that will affect the efficiency of future supply solutions. In looking beyond ongoing replacement of the existing line, broadly speaking, ElectraNet faces the decision to either:

- build a 'minimum capacity' 132 kV option now – while this option will involve lower upfront costs, it may end up costing more over the long-term (if mining load and/or renewable generation develops on the Eyre Peninsula) and risks suboptimal outcomes; or

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[25] Elements of the transmission network include lines, transformers and other network equipment.

- invest in slightly greater network capacity now to get the 'option value' of upgrading the network (or part of it) to 275 kV at a later date if mining load and/or wind generation develop – while this option involves a greater cost upfront, it may more cost-effectively accommodate mining load and/or wind generation developments in the future, if they eventuate; or

- build all or part of the network to 275 kV initially – this would cost more upfront but would allow mining load and wind generation to connect as soon as the new network is commissioned. However, it also carries a risk that the additional network capacity could be built before it is needed, or not needed at all.

This RIT-T has therefore assessed which of these high-level options is the most prudent and efficient choice to make now considering the various uncertainties surrounding future development on the Eyre Peninsula.

We note that the ISP in its base case assumed that a replacement of the existing lines on the Eyre Peninsula with a double circuit 132 kV line would proceed. The ISP includes a high level consideration of a potential upgrade of the network to a double circuit 275 kV line to Yadnarie to connect additional generation, and concludes that this may be required in the late 2030s under its Neutral case assumptions. However, the ISP does not explicitly consider the implications of the development of potential mining loads on the Eyre Peninsula or the option value arising from initially constructing higher rated lines.

4. Submissions to the Project Assessment Draft Report

We received 12 submissions to the PADR, representing a range of views and interests from:

- local Eyre Peninsula representatives and individuals;[26]
- wind farm developers and mining companies;[27]
- the party currently providing network support at Port Lincoln (Engie);
- South Australia's primary Chamber of Commerce and Industry and Employer body (Business SA); and
- Professor Simon Bartlett from the University of Queensland.

Five of these parties supported the preferred option that was identified at the PADR stage, i.e. a 'set and forget' option comprising a double-circuit 275 kV line between Cultana and Yadnarie, and a double-circuit 132 kV line between Yadnarie and Port Lincoln (Option 4B). Four parties requested that a larger capacity option be considered, while two parties expressed the view that a smaller capacity option could be optimal.

This section summarises the key issues raised in submissions and how they have been incorporated into the analysis in this PACR.

A number of parties requested additional transparency in relation to the wholesale market modelling undertaken. In response to this, we have prepared Appendix G, which provides material clarifying the modelling approach.

In addition, Engie raised a number of detailed questions regarding the wholesale market modelling, which have led to some revisions to the modelling in this PACR, and have been explicitly addressed in Appendix H.

4.1 The use of least-cost modelling for RIT-T planning purposes

Engie queried the use of the least-cost modelling approach and stated that the difference between the adopted least cost model and an 'actual competitive electricity market' will distort the calculated costs and benefits. Engie stated that least cost modelling is more representative of a central planner, or a single owner optimising its supply portfolio, rather than a competitive electricity market and suggested that it does not take account of the fact that, in a competitive market, generators need to achieve revenue adequacy to meet both variable and fixed costs for their assets for sustained operation.[28]

[26] The District Council of Elliston, the District Council of the Lower Eyre Peninsula, the Energy Security for South Australia Working Party, the Regional Development Australia Whyalla and Eyre Peninsula and the Eyre Peninsula Local Government Association.

[27] The Eyre Peninsula Mineral & Energy Resources Community Development Taskforce, Iron Road, Meridian Energy, South Australian Chamber of Mines & Energy.

[28] Engie submission to the PADR, p. 2.

We note that least cost modelling is commonplace for electricity network planning exercises and is a requirement of the RIT-T.[29] It is employed by AEMO in its national transmission planning, such as the ISP and the previous NTNDPs.[30] Furthermore, we note that the least cost modelling used in this RIT-T assessment draws on the same inputs (e.g. generator cost assumptions) as that used by AEMO in the ISP.

Appendix G provides greater detail on the least cost modelling applied as part of this RIT-T, as well as how it draws on the AEMO ISP inputs (including how variable and fixed costs are accounted for).

ElectraNet and HoustonKemp held a number of teleconferences with Engie to expand on and further understand the queries in its submission. Appendix H responds to each of these in-turn.

Engie also raised a question about the treatment of generator auxiliary load in the demand forecast used. In particular, Engie noted that the demand forecasts used in the PADR assessment appeared to draw on operational demand from the AEMO Electricity Statement of Opportunities (ESOO), which is on a 'sent out basis', and do not include generator auxiliary demand (i.e. demand used by generators themselves).[31]

ElectraNet notes that the approach to accounting for auxiliaries in the PADR was due to a minor transposing error in the modelling, which has been corrected in the PACR modelling. The inclusion of auxiliary demand in the PADR modelling adds approximately 1 to 6 per cent to the demand forecasts, and would not have changed the findings of the PADR.[32]

The PACR analysis correctly captures auxiliary load. In addition, the modelling in section 9 of this PACR shows that the overall findings are largely insensitive to the assumed demand forecasts generally.[33]

4.2 Consideration of larger and smaller capacity options

A number of parties considered that Option 4B only goes part of the way to realising the total renewable energy potential on the Eyre Peninsula and that a larger capacity option should be pursued (e.g., a 500 kV option).[34]

We appreciate that the Eyre Peninsula is considered to encompass high quality renewable energy resources and that a higher capacity and/or different routed option to those considered would enable more of these potential resources to connect to the grid.

29 AER, *Regulatory Investment Test for Transmission*, June 2010, pp. 8-9.

30 See, for example, AEMO's capacity outlook model for the NTNDP: AEMO, 2016 NTNP Methodology and Input Assumptions, December 2016, p 7.

31 Engie submission to the PADR, p. 3.

32 We have re-run the PADR modelling to address Engie's point about over-representing demand on account of excluding auxiliaries and found that the inclusion of auxiliary load does not change the overall finding of the PADR. Moreover, the addition to demand from this correction is well within the upper demand sensitivity run in the PADR.

33 In particular, as set out in section 9.8.1, Option 4D remains the preferred option under all demand sensitivities but is ranked effectively equally with Option 2 (and Option 2B) under the weak demand sensitivity. For each of the demand sensitivities that we have investigated, Option 4D has positive net market benefits.

34 The Energy Security for SA Working Party, the District Council of Elliston and the Regional Development Australia Whyalla and Eyre Peninsula and the Eyre Peninsula Local Government Association.

However, the RIT-T framework is prescriptive in that it requires us to identify the preferred option as that which has the highest estimated net market benefits.

Our assessment is that the significant cost of 500 kV network options would not be justified in terms of the *additional* market benefits such an option can be expected to deliver over and above the 132 kV and 275 kV options – in particular:

- in response to submissions on the PADR, we developed a detailed estimate of a 500 kV option, as the cost of building a 500 kV transmission network on the Eyre Peninsula, in-line with the proposals in submissions, and found that it is expected to have a capital cost in excess of $2 billion, which is more than three times the most expensive credible option considered; and
- there are not expected to be commensurate *additional* market benefits associated with this option, driven primarily by the updated assumptions regarding the relative quality of the wind resource on the Eyre Peninsula to be consistent with the AEMO ISP assumptions (outlined further in section 6.3 below).

These observations resulted in the conclusion that a 500 kV option would not be a credible option for inclusion in the quantitative assessment.

Other parties considered that a lower capacity option than Option 4B is preferred, including options that make use of the existing line.[35] In response to this, we included two new lower capacity options in the assessment that involve reconductoring sections of the existing line and building a new 132 kV line on a separate easement – one via Yadnarie and another along a geographically diverse path via Wudinna (Options 2B and 3B, respectively). The modelling of these options is detailed in section 9.

4.3 Assumed uptake of wind on the Eyre Peninsula

A key driver of the results in the PADR related to the quantity and relative quality of new wind farms assumed to locate on the Eyre Peninsula in the modelling, based on the most recent comprehensive study of the wind resource available at the time (the 2010 'Green Grid report').[36]

A number of parties queried the assumed uptake of wind generation on the Eyre Peninsula following an upgrade.[37]

Since the PADR was released, modelling by the AEMO for the ISP has found no material difference in wind capacity factors between the Eyre Peninsula and the Mid North region of South Australia. As outlined in section 2 above, this is a key change in assumptions from the PADR, and we have aligned our underlying modelling assumptions with the ISP in the PACR assessment. The updated modelling has found that there is now limited new wind generation forecast to be built on the Eyre Peninsula, reducing the associated wholesale market benefit.

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35 Business SA and Simon Bartlett.

36 Baker and McKenzie, WorleyParsons & Macquarie Bank, *Green Grid – Unlocking Renewable Energy Resources in South Australia*, 2010, p. 27.

37 Business SA, Submission to Eyre Peninsula Electricity Supply Options, 19 January 2018, p 3; Bartlett, S, Submission to the Eyre Peninsula Electricity Supply Options, 18 January 2018; Engie, Eyre Peninsula Electricity Supply Options Project Specification Consultation Report, 25 January 2018, p 9; and RDAWEP, Eyre Peninsula Electricity Supply Options RIT-T Draft Report – Submission, 18 January 2018

While the revised wholesale market modelling finds that there is limited benefit from new wind farms locating on the Eyre Peninsula, all options (except Option 1) do relieve constraints on existing wind farms and reduce losses, which results in wholesale market benefits. The approaches to estimating the benefit from these relieved constraints are detailed further in section 6.3 below.

The options considered in this RIT-T do create opportunities for future new renewable development on the Eyre Peninsula. In particular, the double-circuit lines between Cultana to Yadnarie would be able to accommodate approximately 500 MW of additional wind or other generation if operated at 132 kV (and a further 500 MW if upgraded to 275 kV)[38], while the 132 kV lines between Yadnarie and Port Lincoln would be capable of accepting about 350 MW of any such developments.

This finding is consistent with the ISP, which assumes Option 4D in its assessment and finds that approximately 450 MW of solar generation locates on the Eyre Peninsula in the late 2030s under a number of its future plans.

4.4 Constraints on existing wind farms on the Eyre Peninsula

Meridian Energy, which owns and operates the existing Mount Millar wind farm on the Eyre Peninsula, noted in its PADR submission that the existing thermal limitations of the current transmission line means that the transfer capacity for existing wind farms is limited due to stability and voltage constraints. Meridian Energy notes that during periods of high wind generation there is no spare capacity on the transmission network, which creates a barrier to entry for new generation and that the current constraints have served to limit investment in even preliminary renewable generation studies within the area.[39]

Meridian Energy notes that voltage stability constraints imposed on the two existing wind farms require them to 'spill' significant quantities of energy, which means the energy which could have been provided by these generators must be replaced with more expensive forms of generation.[40]

The impact on existing wind farms has been explicitly considered in the wholesale market modelling in the PACR (and is detailed in section 6.3 below).

Meridian Energy also notes that marginal loss factors (MLFs) for the region can be expected to improve under an option with 275 kV capacity.[41] We agree that this is the case and note that the MLFs have consequently been updated since the PADR was released, as outlined in section 8.4 below.

39 Meridian Energy, Eyre Peninsula Electricity Supply Options, 17 January 2018, pp 1-2.

40 Meridian Energy, Eyre Peninsula Electricity Supply Options, 17 January 2018, p 2.

41 Meridian Energy, Eyre Peninsula Electricity Supply Options, 17 January 2018, p 2.

4.5 Mining developments on the Eyre Peninsula

SACOME noted that two graphite mining projects on the Eyre Peninsula have had approvals either recently granted or are in the process of approval.[42] If ultimately commissioned, these would likely require connection to the Eyre Peninsula electricity network. SACOME notes that these recent developments support a 275 kV solution being pursued for the Eyre Peninsula.[43]

As outlined in section 7.4 below, we engaged AME Research to assess in detail the likelihood of potential mining developments on the Eyre Peninsula developing over the assessment period. AME Research independently assessed the probability of the various mining loads identified progressing in the future. The AME final report is included as Appendix L and the results are summarised in section 7.4 below.

While AME is of the view that there is a greater than 50 per cent chance of Iron Road coming online over the next 15 years, it considers that other potential mining loads on the Eyre Peninsula are not expected to come online over this period. The AME advice has been incorporated in our 'core' PACR analysis and represents a significant reduction in the likelihood of mines developing than was assumed in the PADR.

Iron Road reiterated in its PADR submission that a vital component for the CEIP is a 275 kV transmission line to provide power to the mine site. Iron Road stated that the intention is that the project will link into the power grid at Yadnarie West substation, which is consistent with the RIT-T assumptions.[44]

As outlined in section 9.5, the results of the RIT-T assessment are sensitive to the underlying assumptions regarding the likelihood that new mining developments will come to fruition on the Eyre Peninsula over the next 20 years. We have therefore undertaken sensitivity analysis in relation to these assumptions (as set out in section 9.5).

4.6 The current network support arrangement at Port Lincoln

A number of parties expressed dissatisfaction with the existing network support arrangement at Port Lincoln, with many commenting on its cost to South Australian customers.[45]

We note that the existing network support has been a feature of supplying electricity to Port Lincoln under the ETC reliability requirements to-date. The modelling undertaken in this RIT-T demonstrates however that continuing to have such an arrangement in-place is expected to be higher net cost than pursuing an alternative network option. In particular, the modelling in section 9 demonstrates that the preferred option ('Option 4D') is preferable to Option 1 under *all* scenarios and sensitivities investigated.

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42 These projects are Lincoln Mineral's Kookaburra Gully Graphite Project near Koppio and Archer Exploration's Campoona Graphite project near Cowell.

43 SACOME, Eyre Peninsula Electricity Supply Options – Regulatory Investment Test for Transmission, 19 January 2018, p 2.

44 Iron Road, Eyre Peninsula Electricity Supply Options – Regulatory Investment Test for Transmission, 18 January 2018, p 1.

45 See: Business SA, Submission to Eyre Peninsula Electricity Supply Options, 19 January 2018, p 2; Engie, Eyre Peninsula Electricity Supply Options Project Specification Consultation Report, 25 January 2018, p 11; and ESSAWP, Eyre Peninsula Electricity Grid Upgrade Solution – Energy Security Future, 2017, p 4.

5. Credible options assessed in this PACR

ElectraNet has investigated the same variants of five broad options for supplying the Eyre Peninsula going forward as in the PADR, which reflect a wide variety of different network capacities and routes. These options range from:

- maintaining equivalent capacity on the Eyre Peninsula to that currently available, i.e., a single-circuit 132 kV line coupled with network support at Port Lincoln; through to
- upgrading the entire network to 275 kV, with two completely divergent network paths from Cultana to Port Lincoln in order to provide greater supply resilience.

Three options have been specifically designed to be flexible and allow for the 'option' of upgrading the capacity in the future, if a certain 'trigger' occurs (options 4C, 4D and 5C). This allows for an assessment of the benefit of spending more upfront to provide flexibility for upgrading that option to 275 kV at a lower cost later, if required.

In addition, two new variants of the 132 kV options have been included in response to submissions received on the PADR. These two new lower capacity options involve reconductoring sections of the existing line and building a new 132 kV line on a separate easement – one via Yadnarie and another along a geographically diverse route via Wudinna (Options 2B and 3B, respectively).

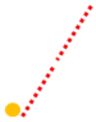
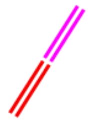
Table 2 (next page) summarises each of the 12 option variants we have assessed in this PACR. Specifically, it outlines the:

- key features of each option, in terms of the network capacity and route(s);
- respective costs under each option, including the *additional* cost that may be incurred in the future for the three options that provide flexibility to upgrade to 275 kV; and
- high-level schematic of the network configuration under each option, including in different future 'states of the world' for the three flexible options that are initially operated at 132 kV, but can be energised to 275 kV later, if required.

To help interpret the high-level network schematics presented in the table, we first present a map of the Eyre Peninsula with key locations and resources highlighted (Figure 9).

Figure 9 – Existing transmission network on the Eyre Peninsula

Table 2 – Summary of the credible option variants assessed

Option overview	Estimated capital cost(s)[46, 47]	Affected/new network[48]
Option 1 (‘business as usual’ base case) Continue network support at Port Lincoln and reconductor sections of the existing 132 kV single-circuit line	$80 million (to reconductor initial sections of the line) $90 million (to reconductor the remaining sections in 2033) $25 million (to replace Yadnarie substation in 2037)	
Option 2 A double-circuit 132 kV line following a Cultana to Yadnarie and Yadnarie to Port Lincoln route, each circuit rated to about 240 MVA	$225 million $20 million (to replace Yadnarie substation in 2037)	
Option 2B A new single-circuit (about 240 MVA) 132 kV line along a parallel route to the existing Cultana to Yadnarie and Yadnarie to Port Lincoln 132 kV single-circuit line, and reconductor sections of the existing 132 kV single-circuit line	$215 million $25 million (to reconductor the remaining sections in 2033) $20 million (to replace Yadnarie in 2037)	
Option 3 Two single-circuit 132 kV lines routes between Cultana and Port Lincoln (one going via Wudinna), each circuit rated to about 240 MVA	$405 million $25 million (to replace Yadnarie in 2037)	
Option 3B A single-circuit (about 240 MVA) 132 kV line following a Cultana to Wudinna and Wudinna to Port Lincoln route, and reconductor sections of the existing Cultana to Yadnarie and Yadnarie to Port Lincoln 132 kV line	$290 million $25 million (to reconductor the remaining sections in 2033) $25 million (to replace Yadnarie in 2037)	
Option 4A Double-circuit 275 kV following a Cultana to Yadnarie and Yadnarie to Port Lincoln route, each circuit rated to about 600 MVA	$330 million	
Option 4B Double-circuit 275 kV between Cultana and Yadnarie, each circuit rated to about 600 MVA, and double-circuit 132 kV between Yadnarie and Port Lincoln, each rated to about 240 MVA	$275 million	
Key: *Reconductored 132 kV* *Network support at Port Lincoln*	& *132 kV single-circuit & 132 kV double-circuit*	& *275 kV single-circuit & 275 kV double-circuit*

46 The scope and capital cost estimates for each of the options has been refined and updated since the PADR, as described in section 8.1. Breakdowns of the network components for each option are provided in Appendix D and summarised in Appendix I.

47 All options also incur $2.9 million cost of installing a 5 MW load bank at Port Lincoln in 2019, with option 1 requiring additional 5 MW load banks at a cost of $2.9 million in each of 2025, 2030 and 2035.

48 These schematics illustrate the affected/new network under each option. Under all options, the existing 132 kV line from Wudinna to Yadnarie remains unchanged and so is not shown in these high-level network diagrams.

Option overview	Estimated capital cost(s)	Affected/new network
Option 4C Double-circuit line following a Cultana to Yadnarie and Yadnarie to Port Lincoln route, each circuit initially energised at 132 kV with a rating of about 300 MVA, with the option to be energised at 275 kV with a rating of about 600 MVA for each circuit if required in the future	$250 million $20 million (to replace Yadnarie in 2037, if not previously upgraded to 275 kV operation) *Plus* $40 million if the Cultana to Yadnarie line is upgraded to 275 kV operation *Or, plus* $80 million if lines are upgraded to 275 kV operation	
Option 4D Double-circuit line from Cultana to Yadnarie initially energised at 132 kV with a rating of about 300 MVA, with the option to be energised at 275 kV with a rating of about 600 MVA if required in the future, and a double-circuit line from Yadnarie to Port Lincoln rated to about 240 MVA	$240 million $20 million (to replace Yadnarie in 2037, if not previously upgraded to 275 kV operation) *Plus* $40 million if the Cultana to Yadnarie line is upgraded to 275 kV operation	
Option 5A Two single-circuit 275 kV lines following separated routes between Cultana and Port Lincoln (one going via Wudinna), each circuit rated to about 600 MVA	$560 million	
Option 5B Two single-circuit lines between Cultana and Port Lincoln (one going via Wudinna), with the Cultana to Wudinna line built and operated at 275 kV and rated to about 600 MVA, and the rest only ever operated at 132 kV with each circuit rated to about 240 MVA	$450 million $25 million (to replace Yadnarie in 2037)	
Option 5C Two single-circuit lines following separated routes between Cultana and Port Lincoln (one going via Wudinna), each circuit initially energised at 132 kV with a rating of about 300 MVA, with the option to be energised at 275 kV with a rating of about 600 MVA for each circuit if required in the future	$455 million $25 million (to replace Yadnarie in 2037, if Cultana – Yadnarie line not previously upgraded to 275 kV operation) *Plus* $25 million if the Cultana to Wudinna line is upgraded to 275 kV operation *Or, plus* $65 million if the Cultana to Wudinna line AND the Cultana to Yadnarie lines are upgraded to 275 kV operation *Or, plus* $110m if all lines are upgraded to 275 kV operation	

Key: *Reconductored 132 kV* · *Network support at Port Lincoln* · & *132 kV single-circuit & 132 kV double-circuit* · & *275 kV single-circuit & 275 kV double-circuit*

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5.1 Options considered but not progressed

This section discusses additional options we have considered, but do not consider technically and/ or economically feasible, and therefore do not consider to be credible options.

In relation to economic feasibility, we note that where two potential options provide the same expected quantum of market benefits, if one option is much more expensive than the other, it is not considered a credible option for the RIT-T. Where two options are expected to provide a different quantum of benefit, the relative costs of the two options should be similar to the difference in relative benefits. Otherwise the relatively more expensive option will not be considered a credible option for the RIT-T.

5.1.1 De-energised re-conductoring version of Option 1

We have considered an alternative version of Option 1 in which the sections of the existing line that require replacement would be de-energised for an extended period of time (about six months) while they are re-conductored. This would require substantial generation support costs while this work is completed and would likely result in outages to many customers on the Eyre Peninsula.

Since this option is not expected to deliver material market benefits over and above Option 1, we consider this option to be economically infeasible.

5.1.2 Generation support at Pt Lincoln and staged build of new double circuit 132 kV line

We have considered the option of continuing with a generation support agreement at Port Lincoln, and undertaking a staged build and commissioning of a new double circuit 132 kV line that addresses the sections of the existing line that require replacement first.

This option is essentially the same as Option 1 above, but involves building a new double circuit 132 kV line instead of re-conductoring.

This option would deliver the same market benefits as Option 1, but at higher cost and so we consider it to be economically infeasible. Specifically, the two approaches for achieving this option would be to either:

- decommission the existing sections that need replacing and rebuild them on the existing easement; or
- build replacement sections on the adjacent easement and cut these across to the existing line when complete, then decommission the existing sections.

The first approach would require substantial generation support costs when the new sections are being built and commissioned to ensure continuity of supply to Port Lincoln. The second option involves constructing new lines, which have a significantly greater cost than reconductoring the existing line – it would also use portions of the 'spare' easement and so would forgo that easement being used in the future to house a higher capacity line, if justified.

5.1.3 Battery support version of Option 1

We have considered an alternative version of Option 1 in which the network support arrangement at Port Lincoln would be provided by means of a battery energy storage system. Conceptually, an appropriately-sized battery would be able to provide backup support at Port Lincoln consistent with category 3 of the ETC, similar to the way our ESCRI-SA battery energy storage system can provide islanded supply to the Dalrymple connection point on the Yorke Peninsula.[49]

We have assessed the cost of this option using costs that were received in response to the SA Energy Transformation Project Specification Consultation Report.[50] This assessment indicates that the present value cost over the 20-year assessment period of a battery support version of Option 1 would be about $150 million to $200 million, in addition to the cost of performing the required reconductoring works.

The total cost of this option significantly exceeds the cost of the generation support version of Option 1 that has been included in the detailed option assessment.

We do not consider that the greater cost associated with a battery energy storage system would be justified by the incremental market benefits it might deliver.

5.1.4 Decommission existing line and replace with a series of micro-grids

We have considered decommissioning the existing 132 kV single circuit line and serving the Eyre Peninsula load with micro-grids. Based on work undertaken, we do not consider that the ETC reliability standards can be economically met through the use of stand-alone micro-grids.

Further, the existing ETC mandates the continuing connection of the existing Eyre Peninsula connection points to South Australia's electricity transmission network, and does not accommodate the use of stand-alone micro-grids for that purpose.

We therefore consider that this option is not economically feasible for this RIT-T.

5.1.5 500 kV transmission options

We have considered a high-capacity 500 kV option for reinforcing supply to the Eyre Peninsula. The scope of the option we considered includes the creation of a loop of 500 kV double-circuit lines from Cultana to Yadnarie, Yadnarie to Port Lincoln, Port Lincoln to Elliston (on the west coast of Eyre Peninsula), Elliston to Wudinna, and Wudinna to Davenport. Each of these lines would be rated to about 2,000 MVA each.

The scope for this option also includes the construction of an additional double-circuit 275 kV line, rated to about 600 MVA per circuit, between Davenport and Cultana. The existing 275 kV lines between Davenport and Cultana would also remain in-service.

The estimated cost of this option exceeds $2 billion. We do not consider that the substantially greater cost associated with building to this capacity would be justified by the incremental market benefits it might deliver.

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49 Information about our ESCRI-SA battery energy storage system project is available from electranet.com.au.

50 Documents relating to the SA Energy Transformation RIT-T are available from electranet.com.au.

5.1.6 Submarine HVDC cable from Port Lincoln to Adelaide via the Yorke Peninsula

We have considered a high-capacity submarine cable option for reinforcing supply to the Eyre Peninsula. We do not consider that the substantially greater cost associated with such an option would be justified by the incremental market benefits it might deliver.

6. Revisions of key market modelling assumptions since the PADR

As outlined in section 2, there have been a number of important developments since the PADR was released that have affected key assumptions in the wholesale market modelling used in this RIT-T. The most significant, in terms of impact on this RIT-T, has been the assumptions developed for AEMO's ISP process.

This section provides an overview of the wholesale market modelling undertaken for the PACR, including outlining the key changes to modelling assumptions and methodologies since the PADR.

6.1 Overview of the market benefits estimated using market modelling

As in the PADR, the market modelling has been used to estimate the following market benefits:

- changes in fuel consumption in the NEM arising through different patterns of generation dispatch; and
- changes in costs for parties, other than the RIT-T proponent (namely generators).

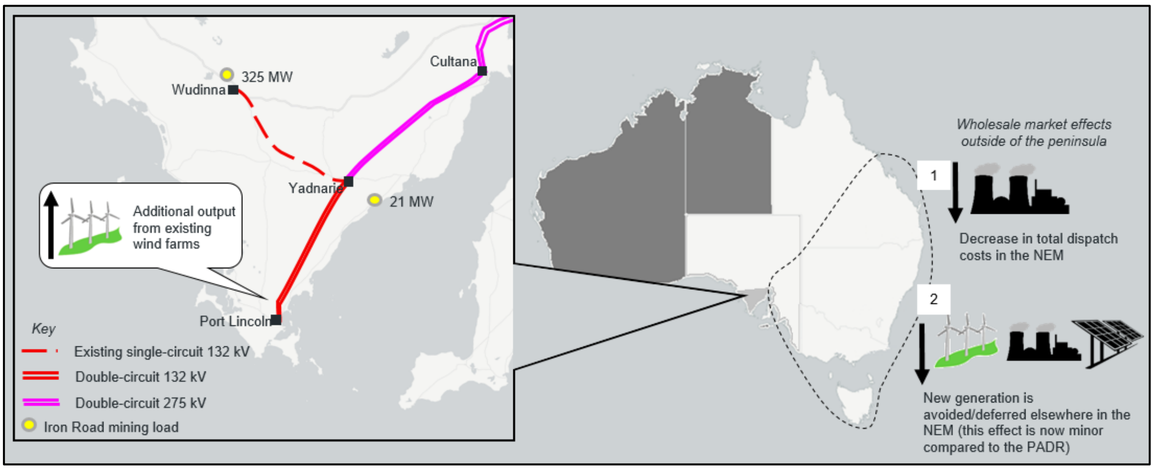
These benefits are expected where credible options allow different patterns of generation dispatch and future construction (and retirement) of generators in the NEM, compared to where the existing single-circuit 132 kV line is retained (Option 1). While in the PADR both of these categories were predominantly driven by the ability of credible options to facilitate additional wind generation connecting on the Eyre Peninsula which cannot be accommodated under Option 1, they are now driven by the relief of constraints on the existing wind farms on the Eyre Peninsula.[51]

Figure 10 illustrates these effects, and the two market benefits above, using Option 4B and the assumed 'state of the world' where only Iron Road's CEIP locates on the Eyre Peninsula as an example. It illustrates how relieving existing wind generation on the Eyre Peninsula results in lower total dispatch costs in the NEM and well as avoided/ deferred new generation build and operation costs.[52]

[51] On account of the ISP finding that there is no material difference between the wind resource quality on the Eyre Peninsula and other locations.

[52] The impact on new generation builds in the NEM is substantially reduced since the PADR and the majority of the wholesale market benefits now come from lower dispatch costs.

Figure 10 – Summary of key wholesale market effects – using Option 4B as an example



6.2 Overview of the market modelling undertaken

As with the PADR assessment, we engaged HoustonKemp to undertake market modelling to assess the market benefits expected to arise under each of the options.

This market modelling has been conducted in the context of a real option analysis framework. Therefore, a moderately simplified market model has been applied to facilitate the large number of simulations to be run within the framework. We consider that this is a proportionate approach that would not affect the outcome of the RIT-T assessment.

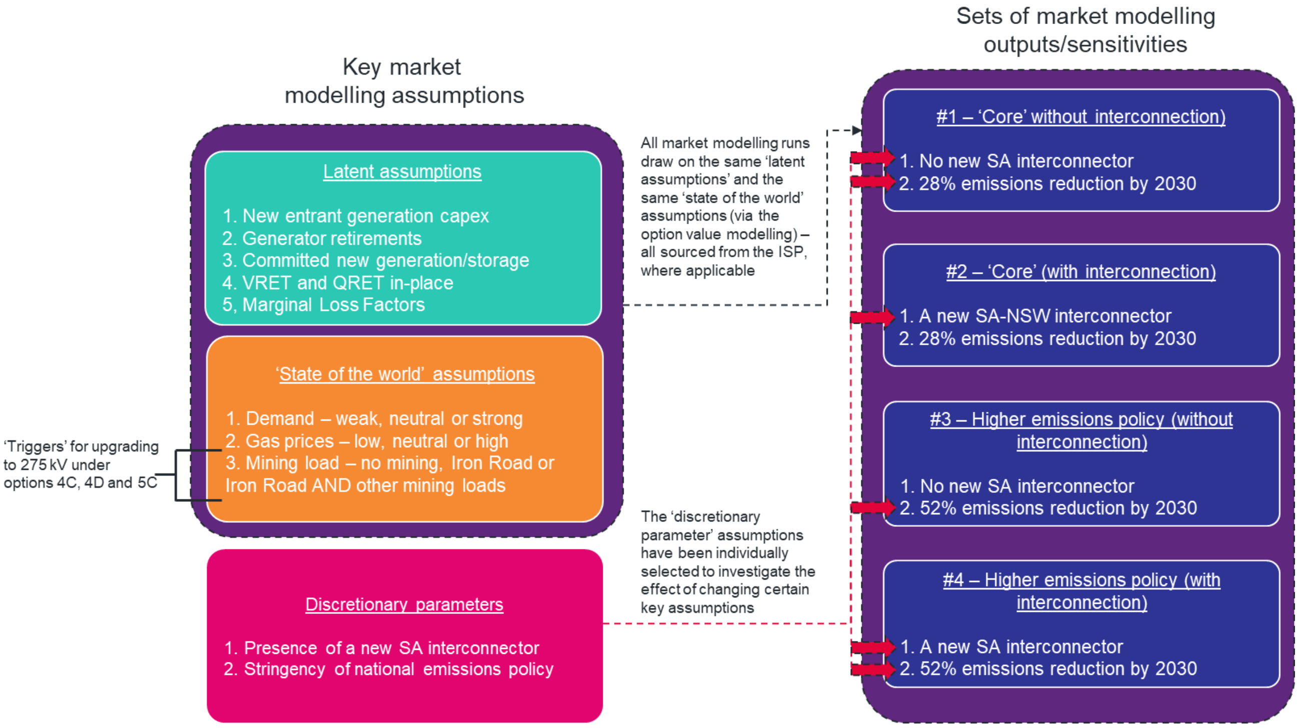
For the purposes of the PACR market modelling, ElectraNet and HoustonKemp have continued to define three sets of market modelling inputs – namely:

- 'Latent' assumptions – these are assumptions that apply across all scenarios and model runs, e.g., generator technical and financial parameters, the stringency of jurisdictional Renewable Energy Targets and capital costs of new entrant generators;
- 'State of the world' assumptions – these are the assumptions that define each 'state of the world' modelled in the option value analysis, i.e., 'a low demand world' vs. a 'high demand world'; and
- 'Discretionary' parameters – these are parameters which represent a material uncertainty with regards to the market modelling. The entire market modelling and option value analysis has been recalculated for each set of discretionary parameters, e.g. development of a new interconnector.

The 'latent' and 'state of the world' assumptions have changed since the PADR to align with the ISP. The remainder of this section summarises how key assumptions have changed since the PADR.

Figure 11 provides an overview of the framework for the market modelling undertaken, including the interaction between these sets of assumptions.

Figure 11 – Overview of the market modelling undertaken in the PACR



In the results for the core scenario, we have applied weightings to each ISP gas price and electricity demand scenario that reflect that the 'base scenario' is considered more likely (and has consequently been given a weight of 50 per cent).

The high scenario and low scenarios have each been weighted 25 per cent, on the basis that there is no evidence to weight one as more likely than the other. This is consistent with the approach taken in the SA Energy Transformation RIT-T PADR assessment.

The 'state of the world' assumptions are a proxy for how key benefit drivers may unfold in the future and include both electricity demand and gas price assumptions, as well as the mining load 'trigger' variables. The state of the world assumptions have a number of effects in the modelling framework – namely:

- triggering network upgrades in the options that possess flexibility (i.e., 4C, 4D and 5C); and
- increasing demand in South Australia (for cases with mining loads).

Table 3 summarises various 'state of the world' assumptions and their source.

Greater detail on the wholesale market modelling methodologies and assumptions is provided in Appendix G.

Table 3 – Various 'state of the world' assumptions and their sources[53]

Assumption	States of the world	Probability	Source
Electricity demand	Strong	0.25	AEMO's 2018 ISP
	Neutral	0.50	
	Weak	0.25	
Gas prices	Strong	0.25	AEMO's 2018 ISP
	Neutral	0.50	
	Weak	0.25	
Mining load	No mining load	0.94 (per year)	AME Research[55]
	Iron Road mine is developed	0.06 (per year)	
	Iron Road and others assumed mines are developed	0.00 (per year)[54]	

The ISP updated a number of key assumptions used in the wholesale market modelling for this RIT-T, i.e.:

- the relative quality of the wind resource on the Eyre Peninsula (compared to other areas, such as the Mid North region of South Australia);
- Marginal Loss Factors for generators on the Eyre Peninsula;
- new entrant generator costs;
- gas price projections; and
- the level of national emissions targets and the treatment of jurisdictional renewable energy policies.

Each of these have been captured in the wholesale market modelling undertaken as part of this PACR.

The most significant of these updates to assumptions is the first one listed, as discussed in section 2 of this PACR. The ISP also assumes that both the VRET and QRET are implemented in full going forward, which differs from the PADR assumption that only the first tranche of the VRET was put in-place (as also discussed in section 2).

53 While the PADR also had the Eyre Peninsula possibly being declared as a renewables precinct as a 'state of the world', this has been removed from the PACR modelling on account of the ISP investigations finding that the Eyre Peninsula wind resource is not materially better than other regions.

54 This state of the world is given a zero chance of occurring in the core assessment but is tested in the sensitivities.

55 Please see section 7.4 for a description of the AME assessment.

6.3 Relieving constraints on existing wind farms

The PADR used a simplified static assumption that an additional 5 MW of wind generation from the two existing wind farms on the Eyre Peninsula would be available to be dispatched each year under all options (besides Option 1). This assumption was based on system studies undertaken at the time and did not play a key role in the overall market benefits estimated as part of the PADR, on account of new wind farms locating on the Eyre Peninsula being the predominant source of wholesale market benefits.

However, we have revisited the planning studies undertaken in light of existing wind farms now becoming the predominant driver of wholesale market benefits to refine the assumptions relating to the wholesale market benefit from relieving the existing constraints. In particular, the market modelling now draws on a lower assumption of approximately 3.6 MW of average additional output in total from the two existing wind farms.

6.4 Expanded interconnection between South Australia and the rest of the NEM

A new interconnector between South Australia and New South Wales has been identified by AEMO in the ISP[56] as an important element of the 'roadmap' for the NEM and as one of its immediate priorities that will deliver positive net market benefits as soon as it can be built. This is consistent with the draft findings of the SA Energy Transformation RIT-T being currently undertaken by ElectraNet.

This PACR therefore investigates, and presents, the wholesale market impacts of all credible options for the Eyre Peninsula both with and without the background assumption of a new interconnector between South Australia and New South Wales. In particular, where we have assumed a new interconnector is present, we have assumed new interconnection at 330 kV between Mid North South Australia and Wagga Wagga in New South Wales via Buronga (i.e. Option C.3i, which is the draft preferred option in the SA Energy Transformation RIT-T PADR).[57]

While the net market benefits of the credible options for this Eyre Peninsula Electricity Supply Options RIT-T were found to be highly sensitive to this background assumption in the PADR, this is not the case in the PACR assessment. This is due to the reduced scope of wholesale market effects between the PADR and the PACR.

6.5 Changes in government and policy affecting South Australian energy security

The market modelling in the PADR made two key assumptions regarding South Australian energy security. In particular, it assumed meeting the South Australian Energy Target that was expected to be put in place at the time as well as an explicit floor on the amount of synchronous generation in the state (in light of the September 2017 assessment by AEMO of system strength in South Australia).

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

[57] Information about the SA Energy Transformation RIT-T is available at https://www.electranet.com.au/projects/south-australian-energy-transformation/.

Following the change in state government since the PADR was released, it is no longer relevant to assume the South Australian Energy Target (as it is not part of the current government's agenda) and so this assumption has been removed in the wholesale market modelling.

In addition, the floor on the amount of synchronous generation has been removed from the market modelling. This is because we are currently working with AEMO to perform detailed investigations into how to address the system strength gap declared by AEMO for South Australia, with the intent to expedite a solution (which means there is no need for an assumed floor on the amount of synchronous generation going forward).

However, we continue to adopt a minimum generation constraint on specific gas fired generators where an interconnector is not in place, to align with the ISP assumptions.

6.6 Alignment with final ISP assumptions

The market modelling undertaken for the PACR is aligned with the assumptions used in the ISP in all material respects.

There are some relatively minor variations because the PACR modelling was finalised prior to the final release of the ISP. For example, wind traces used in our modelling differ from those applied in the ISP, as those traces were not released until after the publication of the ISP.

However, we have compared the outcomes of the ISP modelling with the modelling undertaken for this PACR and assessed that the adoption of the ISP wind trace assumptions would only have a minor impact on the modelled outcomes in the PACR and would likely lead to a minor increase in market benefits relative to those presented here. This is principally because:

- the difference between the capacity factor of new entrant wind on the Eyre Peninsula and its main substitute region, ie, the Mid North, is consistent across the ISP and the modelling conducted for the PACR. This means that benefits from substitution of new investment between regions within South Australia is consistent across the two sets of modelling assumptions;
- the capacity factors for the Eastern Eyre Peninsula assumed in the ISP are higher than those assumed in the modelling for this assessment and so, all else being equal, the value of unlocking this resource in the PACR would have a greater value under the ISP assumptions. However, in any case the extent of new investment in wind generation is not a primary driver of market benefits, given the relatively high marginal loss factors for generators located on the Eyre Peninsula;
- the majority of market benefits are derived from increased output from existing wind farms and the magnitude of the increase in this output is independent of capacity factor assumptions; and
- our modelling placed less significant restrictions on the new build of gas generation in the future compared to those reflected in the ISP – incorporating these restrictions would likely increase the value of unlocking the ability to develop new generation capacity on the Eyre Peninsula.

Changes to wholesale market modelling assumptions would have to yield substantial changes to the estimates of net market benefits to change the preferred option.

7. A more granular approach to estimating option value

As outlined in the PADR, this RIT-T is the first to formally include real options analysis. 'Option value' in this RIT-T arises in relation to the three options that have been defined to be flexible, and which involve building some additional network capability now to gain the 'option' of upgrading the network, or part of it, to a greater capacity later in response to external triggers, i.e., Options 4C, 4D and 5C. The market benefits afforded through the flexibility to easily upgrade the network capacity in the future if it is efficient to do so is referred to as 'option value' under the RIT-T.

Option value analysis essentially extends the range of future states of the world that can be considered and so enables a more sophisticated treatment of uncertainty. The modelling techniques used consider the relationships between different uncertain parameters, and how probabilities may change over time, in a structured way. Overall, applying real option value techniques has allowed for a far greater number of future states of the world to be modelled in this RIT-T than under a simple 'scenario analysis'.

The PADR analysis made a number of simplifying assumptions regarding the timing of the emergence of mining loads in order to accommodate the 'option value' analysis within the broader cost benefit and wholesale market modelling framework used for the RIT-T assessment.

This section outlines the revised assumptions and how they build on the approaches taken in the PADR assessment. The refined option value modelling continues to interface with the wholesale market modelling to derive the overall cost benefit results.

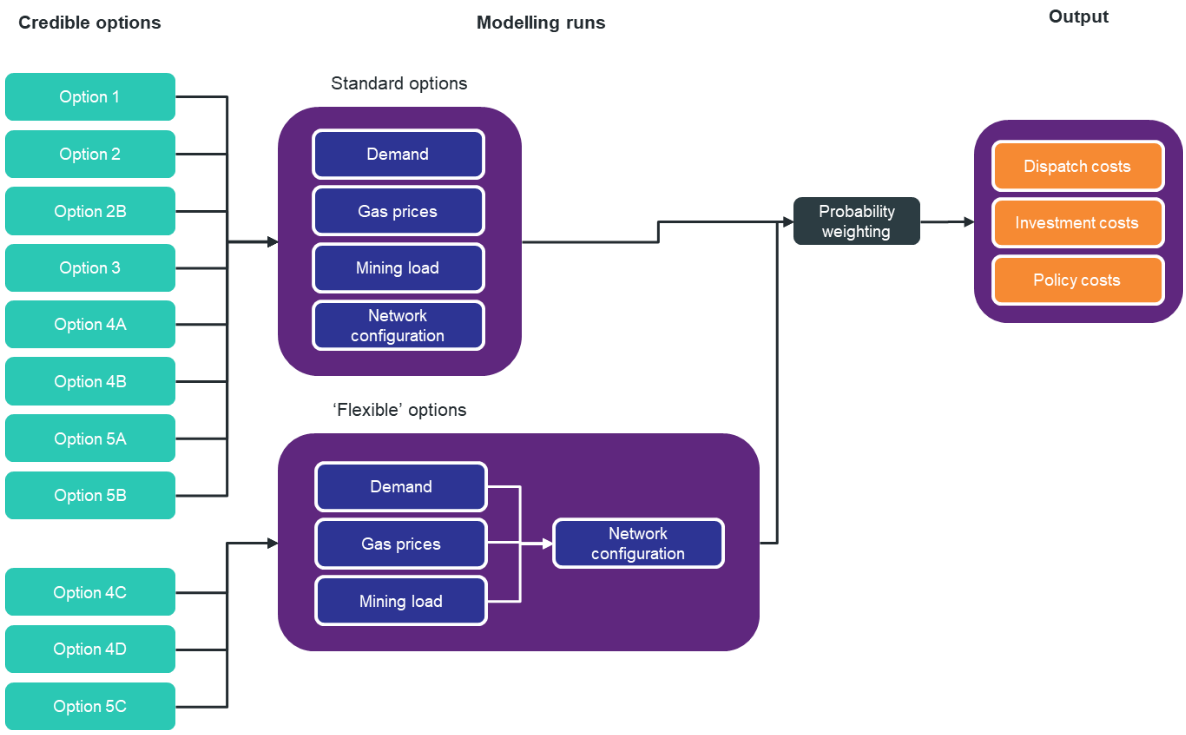
7.1 General structure and framework for estimating 'option value'

Figure 12 outlines the framework for the option value analysis, which is consistent with that in the PADR. In particular, we distinguish between options that involve a single upfront decision ('standard options'), and those that allow optimisation of future decisions ('flexible options') from which 'option value' is derived.

For the standard options, the market benefits have been assessed arising under each demand, gas price, network configuration and mining load scenario. For the option value options, market benefits have been estimated for each of the 'state of the world' variables while upgrade decisions have been made based on the values of the trigger variables.

The cost outputs from the market modelling are broken out into three categories, i.e., dispatch costs, investment costs and policy costs. In this context, policy costs refers to penalties under the current Large-Scale Renewables Energy Target.

Figure 12 – Overview of the option value framework



7.2 Three refinements to the modelling of 'option value'

The PADR assessment made several simplifying assumptions to make the option value analysis tractable in terms of model run-time – namely:

- an initial decision was assumed to be made in FY2018 – for the purposes of the option value analysis, construction for each option was assumed to be completed in FY2021; and
- there were then two further decision points at five-year intervals, at which times new information becomes available with regards to the trigger variables, and upgrade decisions can be made based on this new information – upgrades then take two years to take effect should they be implemented.

The granularity of these assumptions has been increased in the PACR, allowing for a more realistic assessment of the benefit associated with the three flexible options.

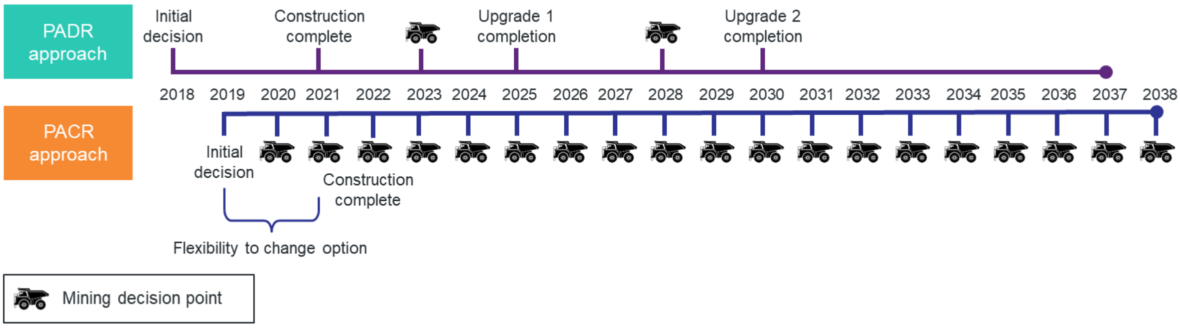
Figure 13 outlines the three key refinements made to the option value modelling framework to reflect a more realistic set of responses to new information as and when it becomes available.

Figure 13 – How the modelling of 'option value' has been refined in the PACR assessment

Modelling Parameter	Simplifying assumption made in the PADR assessment	Refined assumption used in the PACR assumption
How often can decisions about upgrading voltage from 132 kV to 275 kV be made	Three decision points regarding upgrading over the 20-year period– an initial decision in 2018 and two further decisions at five-year intervals	Annually
First year a mine could make a binding connection agreement	2023	2019
Interaction between constructing an option and mines committing	Not previously accommodated for	Incorporated flexibility for the construction plan to change during the construction period to accommodate higher capacity substations, where mining load seeks connection *during* the construction period

Figure 14 translates these refinements into the sequence of events assumed in the option value analysis framework. In particular, it shows the increased granularity in the PACR modelling of option value, which maps more closely to what would be expected in reality.

Figure 14 – Updated option value timeline assumed in the PACR



In applying the real options analysis, HoustonKemp continued to simulate wholesale market outcomes under all feasible combinations of the key variables, reflecting the different potential future states of the world. These key variables, include not only whether or not mining load develops but also electricity demand, gas prices and renewable energy policies, all consistent with the ISP assumptions.[58]

The market benefit estimates from each of these model runs were then weighted by assumed probabilities to estimate the expected market benefits across all scenarios. In addition, HoustonKemp conducted sensitivity analysis to ascertain how sensitive the preferred option is to assumptions regarding probabilities of different future states of the world occurring. The results of these sensitivities are reported in Section 9 below.

58 Greater detail on the wholesale market modelling approach and assumptions is provided in Appendix G.

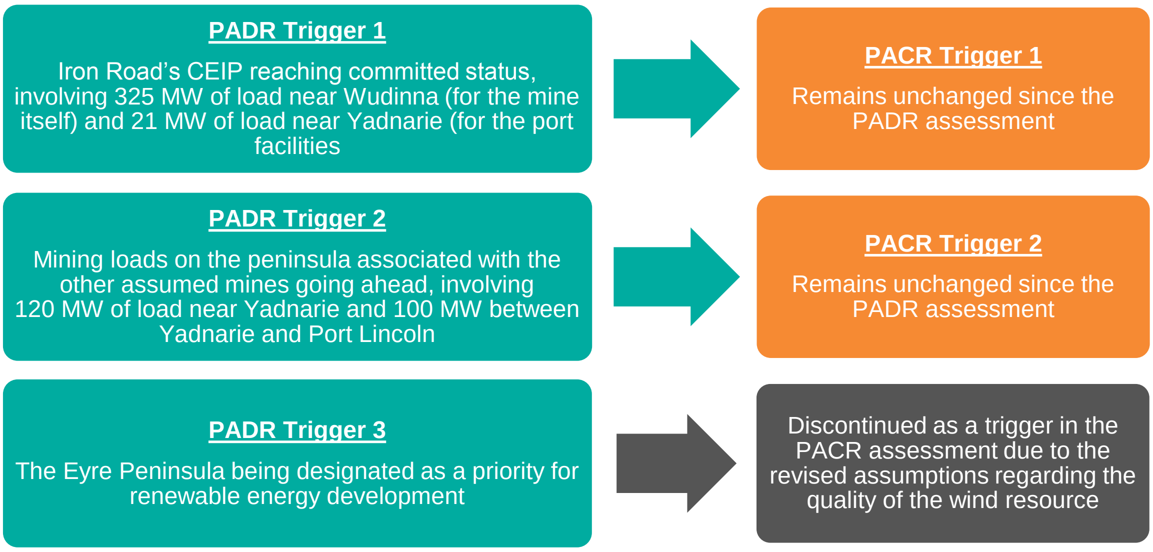
Relative to the PADR, the analysis conducted for the PACR indicates that there is more option value associated with the flexible options considered. We discuss the reasons for this in Section 9.

7.3 The option value modelling now only has two 'triggers'

The PADR assessment assumed three trigger variables in the option value modelling, reflecting a combination of potential mining developments and as well as renewable energy policies that may emerge going forward (in particular, the Eyre Peninsula being designated as a Renewable Energy Zone, 'REZ', at some point in the future).

The reduced likelihood of the Eyre Peninsula becoming a REZ has meant that the PACR modelling has been able to reduce the number of triggers to two (Figure 15).

Figure 15 – The PACR option value modelling assumes two 'trigger' variables



The PADR also made a simplifying assumption that the two mining triggers are dependent on one another. The PACR assessment relaxes this assumption and allows these two triggers to occur independently, which is considered a more realistic assumption. In particular, while there is a certain dependency between these two events (on account of their inherent link to world minerals prices), the decisions to develop these mines are made separately by different companies.

7.4 The likelihood that mining load will emerge on the Eyre Peninsula

A key assumption driving the net market benefits of the flexible options is the underlying assumed probability of mining loads developing on the Eyre Peninsula going forward. In particular, the greater the perceived likelihood, the better the flexible options appear relative to the low capacity versions.[59]

[59] This applies up until a point, ie, at some (high) probability of mining loads proceeding, the fixed high capacity options become preferred.

This is inherently a forecast assessment of the likelihood that the various mines will proceed. In the PADR, we made a number of assumptions about these probabilities and, recognising the uncertain nature of these assumptions, stress tested the results to a range of alternate assumptions.

Since the PADR, we have sought independent advice from mining advisory firm AME Research on the likelihood of the various potential mining developments on the Eyre Peninsula progressing.

AME is of the view that there is a greater than 50 per cent chance of Iron Road coming online over the next 15 years.[60] AME considers that the other potential mining loads on the Eyre Peninsula are not expected to come online over this period (and has effectively assumed they have a zero per cent probability, which has been reflected in the core modelling results in this PACR).

The table below summarises the different 'core' assumptions regarding mining load likelihood between the PADR and the PACR.

Table 4 – Mining load likelihood assumed in the PACR and PADR

Assumption	PADR[61]	PACR
Iron Road	40 per cent chance every five years	Greater than 50 per cent chance over the next fifteen years (approximately 5.8 per cent chance each year)
Other mines	20 per cent every five years	0 per cent

The AME advice has been incorporated in our 'core' PACR analysis and represents a significant reduction in the likelihood of these mines developing than was assumed in the PADR.

60 AME estimates that this likelihood is equivalent to an approximate annual likelihood of 5.8 per cent over the next fifteen years.

61 As outlined above, the PADR made a number of simplifying assumptions regarding mining loads developing over the assessment period. In particular, at every 'decision point' in the option value modelling there was assumed to be a 60 per cent chance that no mining would develop, a 20 per cent chance that just Iron Road would develop and a 20 per cent chance that both Iron Road and other mines would develop. Table 2 of the PADR outlines this further.

8. Other assumptions used to estimate expected market benefits

This section details several other assumptions and the approaches taken to estimate the net market benefits of the credible options considered.

In particular, it outlines key assumptions related to the following costs and market benefits (and categories under the RIT-T) and changes since the PADR assessment:

- transmission cost revisions;
- avoided costs associated with not re-signing a long-term network support contract for Port Lincoln (i.e. the 'changes in costs for parties, other than the RIT-T proponent' market benefit under the RIT-T);
- improved supply reliability to customers on the Eyre Peninsula (i.e. the 'changes in involuntary load shedding' market benefit under the RIT-T); and
- reduced transmission losses from replacing the existing lines (i.e. the 'changes in network losses' market benefit under the RIT-T).

We note that the same categories of market benefit that are considered not material for this PACR apply as in the PADR (a summary of these have been reproduced in Appendix F of this PACR. In addition, the 20-year assessment period and the commercial discount rate assumptions have not changed since the PADR (these are also reproduced in Appendix F).

8.1 Transmission cost estimates have been refined

We have refined estimated transmission costs since the PADR. These include: the capital costs for the options; the connection costs associated with connecting new mining loads; and the operating and maintenance costs associated with the reconductoring of the existing line under the base case.

Table 5 outlines why and how each of these costs have changed.

Table 5 – Summary of the ten credible option variants assessed

Cost assumption	Change since the PADR
The capital costs of the options	We have refined the capital cost estimates of each of the options to a greater level of accuracy and updated them based on the latest cost input drivers. In particular, we have focussed considerable effort on understanding the cost of constructing new 132 kV and 275 kV lines. This has affected all options, with changes to option components ranging from 19 per cent lower to 12 per cent higher than in the PADR. All changes are within the ±25 per cent level of accuracy that the capital cost estimates were estimated to in the PADR. The latest capital cost estimates are estimated to within a ±15 per cent level of accuracy. Appendix I summarises how the costs of every component of each option have changed since the PADR.

Cost assumption	Change since the PADR
Mining connection costs	As with the capital costs of the options, we have also refined the transmission costs associated with the assumed mining loads connecting to the network to be more accurate and based on the latest input cost drivers. The revisions have resulted in changes in the assumed mining connection costs (which are avoided for the options that can accommodate new mining load) ranging from 14 per cent lower to 2 per cent higher than in the PADR.
Operating costs of the reconductoring option	The annual operating and maintenance costs associated with the reconductoring option (Option 1) were assumed to be approximately $500,000 per annum in the PADR. This has been increased to approximately $1.6 million per year in the PACR assessment, which reflects more detailed forecasts of operating expenditure refurbishment costs for the existing lines over the ten years from 2018-19 to 2027-28.

None of these revised transmission cost estimates between the PADR and PACR have materially affected the estimated net market benefits of the options, either generally, or for specific options (relative to others).

8.2 Avoided future network support costs at Port Lincoln

As outlined in the PADR, we released a formal Request for Tender (RFT) on 28 September 2017 that requested financial and operating parameters from network support proponents.

We assessed these responses and developed assumptions for the PADR regarding future network support costs at Port Lincoln for Option 1. This assessment resulted in an annualised cost of $9.1 million being assumed, which involves consideration of connection costs, annual standby charges quoted (where relevant), cost per ‘start-up’ and running charges.

We progressed discussions with potential providers of network support at Port Lincoln since the PADR was released and have concluded negotiations for interim support. We have also revised the connection charge component of these costs to better reflect future operating and maintenance costs.

As a result of accounting for the latest available information from potential providers of future network support and the revised connection cost component, assumed network support costs for Option 1 have reduced by $1.3 million per year from the PADR assumption to $7.8 million per year.

Forecast future decreases in minimum demand at Port Lincoln due to the forecast continued uptake of rooftop solar PV necessitates the installation of equipment such as resistive load banks to ensure that any network supply arrangement remains able to provide reliable islanded supply to Port Lincoln at times of low demand.

The extra cost that this would add to the future cost of network support has been included in our analysis, with a 5 MW load bank needed in 2019 for all options, and further 5 MW load banks needed for Option 1 in 2025, 2030, and 2035. We have based our assessment on an estimated total installed and connected capital cost of $2.9 million for each 5 MW load bank.

While options 2 to 5 (including A, B, C and D variants) involve the construction of either a double-circuit or two single-circuit lines, and allow the current ETC reliability standard to be met without a future network support agreement at Port Lincoln, a network support arrangement for Port Lincoln would need to be maintained until one of these options can be commissioned. We have modelled these costs using information provided by network support proponents in response to the RFT and updated the connection costs since the PADR. These interim network support costs used in the PACR are as follows:

- $8.8 million per annum for a 3-year network support arrangement (i.e. applicable to Options 2 & 4 variants); and
- $7.8 million for a 5-year network support arrangement (applicable to Options 1, 3 & 5 variants).

8.3 Reduced unserved energy to customers

A key benefit for customers that reside on the Eyre Peninsula is the expected reduction in the amount of load that would be shed on the Eyre Peninsula, including following severe weather events. Under the RIT-T assessment, the benefit associated with the expected reduction in expected unserved energy is valued at the VCR, expressed in $/kWh.

We have estimated the change in the expected unserved energy under each of the investment options and states of the world, relative to Option 1. Transmission-related expected unserved energy under the options that do not involve geographically diverse paths has been calculated to be 80 per cent lower than Option 1. Transmission-related expected unserved energy under the options with geographically diverse paths has been determined to be negligible.

Key changes since the PADR include:

- consideration of the reliability improvement that options would deliver for industrial load on the Eyre Peninsula (the PADR assessment only considered residential load); and
- consideration of the typical length of historical transmission-related interruptions on the Eyre Peninsula.

The calculated expected unserved energy shows a slight improvement of the upgrade options compared to Option 1, due to inclusion of the above.

The calculated expected unserved energy has then been multiplied by AEMO's estimated VCRs for residential and industrial customers in South Australia of $40,733 and $15,998 respectively.[62]

[62] These estimates were derived by adjusting the AEMO's estimates from the 2014 value of customer reliability review by inflation (see AEMO, Value of Customer Reliability Review, September 2014).

While increases in the reliability of electricity supply are very important to the homes and businesses on the Eyre Peninsula in terms of reducing the frequency and duration of any outages, the identification of the preferred option is found to be insensitive to underlying VCR assumptions, indicating that all options make a similar contribution to delivering improved reliability outcomes.

8.4 Reduced transmission losses

Since the PADR was released, we have undertaken additional network modelling in order to ascertain the reductions in electrical losses under each of the credible options, relative to the option of reconductoring the four poor-condition sections of the existing line (i.e. Option 1).

Transmission losses have been captured in the market modelling through adjusting the marginal loss factors that apply to existing generators and any potential new generation connections located on the Eyre Peninsula, for each possible network configuration under the various credible options.

Under the current network configuration Cathedral Rocks and Mount Millar wind farms are subject to substantial losses,[63] largely because the high impedance of the current lines connecting the wind farms back to the 275 kV network at Cultana. This point was raised by Meridian Energy in its submission to the PADR and is discussed in section 4.4 above.

Any network configuration that leads to an increase in the voltage of the network will result in a reduction to the losses that these generators are subject to. A reduction in losses means that less energy needs to be produced to meet the same amount of demand from end consumers. Therefore, a reduction in losses results in benefits due to the avoidance of dispatch costs associated with generation that would otherwise have been required to meet demand.

We have conducted internal modelling and utilised results from studies on loss factors for wind farms on the Eyre Peninsula commissioned by AEMO to estimate the loss factors applying to new and existing generators. These results were used to calibrate loss factors to be applied to existing and new loss factors for each network configuration.

Appendix I presents the specific loss factor assumptions applied in the market modelling under each network configuration in the PACR assessment. The modelling also assumes that losses for existing plants on the Eyre Peninsula fall over time in a linear manner, reflecting the increasing connection of distributed solar PV in the region. High voltage options result in a reduction in this rate of decline.

[63] For example the marginal loss factor for Cathedral Rocks wind farm in 2017-18 was estimated by AEMO to be 0.8965, meaning that approximately 1.1 MW of generation is required to meet an additional 1MW of load at the regional reference node.

9. Estimated net market benefits

The preferred option in the earlier PADR was a 'set and forget' option comprising a double-circuit 275 kV line between Cultana and Yadnarie, and a double-circuit 132 kV line between Yadnarie and Port Lincoln (i.e. Option 4B).

The assessment at the time found that there was expected to be sufficient market benefits associated with new wind farms locating on the Eyre Peninsula to justify this option over more flexible options that initially operate sections of the new line at 132 kV but allow them to be energised to 275 kV at some point in the future, if required.

This section presents the updated assessment of each option's net market benefits, taking account of the key changes outlined in the preceding three sections.

In particular, it presents the costs and gross market benefits estimated for each credible option under the 'core' set of assumptions, as well as the consequent, estimated net market benefits. The 'core' set of assumptions reflect our weighted view regarding key underlying assumptions likely to affect the magnitude of net market benefits estimated for each option.

These core assumptions have been stress-tested through various sensitivity tests to ensure the robustness of the overall results (the results of these sensitivity tests are presented at the end of this section).

This section also reports on key sensitivities relating to changing input assumptions in the core results – these include:

- an increase in the emission reduction required by 2030 to 52 per cent (consistent with the ISP's strong scenario)
- the assumed likelihood of mining load connecting on the Eyre Peninsula in the future, as it is found to be a key driver of benefits
- lower and higher assumed network support costs at Port Lincoln.

This section also presents the results of general sensitivities undertaken, including assumed gas prices and electricity demand, assumed discount rate and capital costs.

While sections 9.2 and 9.3 present the results for *all* options, the other sections only present the results for the options going via Yadnarie. All the Wudinna options are found to have significant negative net market benefits for all sensitivities and so have been excluded from these sections. Appendix J presents the estimated net market benefits for all options.

Appendix J presents the detailed breakdown of these costs and benefits, while Appendix K provides further insight into the key wholesale market benefits estimated.

9.1 Selection of the 'base case'

As stated in the PADR, a 'business as usual' base case has been adopted for this RIT-T as a 'do nothing' alternative would result in significant unserved energy to the Eyre Peninsula, which is an unacceptable and unrealistic outcome, and therefore not an appropriate basis for comparison. The 'business as usual' base case reflects the investment the AER included in its recent final revenue decision for ElectraNet for the 2018-19 to 2022-23 regulatory control period (i.e. Option 1 where the existing line is reconductored and network support is continued at Port Lincoln to meet ETC requirements).

The results in this section are all presented relative to the business as usual base case, with the exception of section 9.3, which compares all options to a 'do nothing' base case for comparative purposes and to estimate the *absolute* benefits.

9.2 Net market benefits estimated for each credible option

The PACR assessment finds that new double-circuit lines from Cultana to Port Lincoln via Yadnarie provide the greatest net market benefit under our 'core' set of assumptions.

Option 4D is estimated to have the greatest net market benefit of all options considered at approximately $60 million with a new interconnector assumed, and $50 million without a new interconnector assumed. This is between $15 million and $11 million more than Option 4B (i.e. the preferred option at the PADR stage), depending on whether a new interconnector is assumed.

The benefits of all options increase if a new interconnector between South Australia and New South Wales is assumed.[64] While Option 4D is estimated to deliver around $2 million more net market benefits than Option 2 (i.e. the second ranked option) under the assumption that no new interconnector is built, this is found to rise to $7 million if a new interconnector is assumed to be built.

Option 4D is still found to be the preferred option with a new interconnector assumed, and the interconnector is estimated to add approximately $9 million to its net market benefits.

When a new SA-NSW interconnector is assumed to be in-place, the wholesale market modelling finds that the interconnector reduces the requirements for gas-fired generation dispatch in South Australia, which is principally replaced by coal-fired generation in New South Wales. Consequently, upgrading the Eyre Peninsula with a new SA-NSW interconnector in place leads to displacement of coal-fired generation in New South Wales and further displacement of gas-fired generation, particularly in South Australia.

In addition, in terms of avoided/ deferred generation benefits, upgrading the Eyre Peninsula leads to less displacement of other wind and solar PV generation in South Australia and increases the deferral and avoidance of investment in renewables in other regions; e.g. Tasmania.[65]

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64 Consistent with the AEMO ISP and the coincident South Australian Energy Transformation RIT-T.

65 While the 'core' results reflect ElectraNet's weighted view regarding future states of the world (i.e. across demand, gas prices and mining scenarios), this paragraph has been informed by the state of the world assuming neutral ISP input assumptions and no new mining load. For the full set of wholesale market effects under other assumptions see Appendix K.

The three figures below show the overall estimated net market benefit for each option that involves new lines going via Yadnarie and the breakdown of costs and benefits.

Figure 16 – Summary of estimated net market benefits for the credible options going via Yadnarie assessed under the 'core' set of assumptions

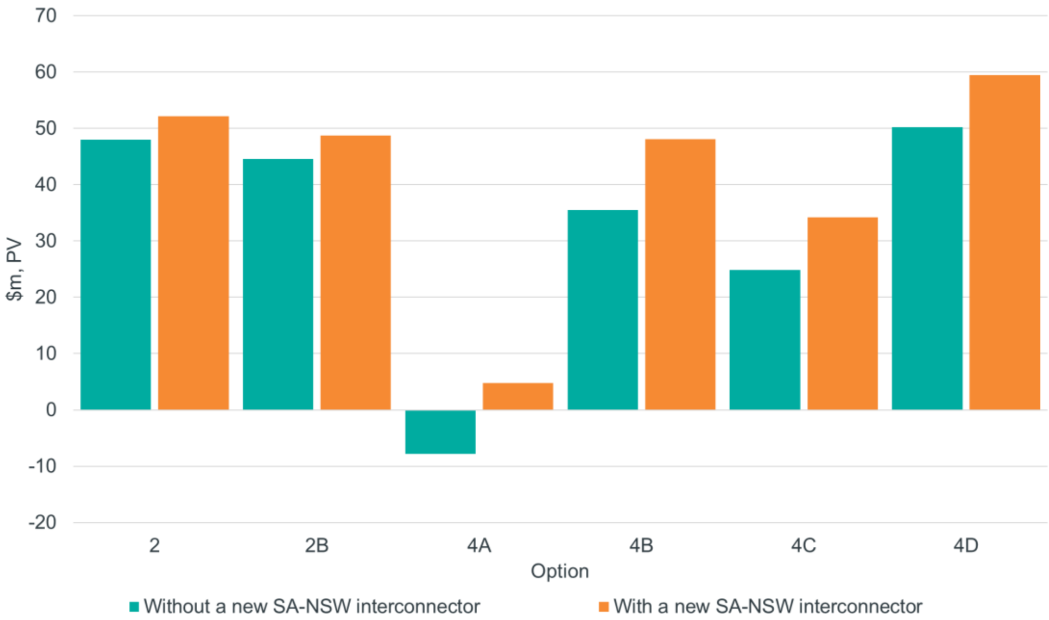


Figure 17 – Breakdown of estimated net market benefits for credible options going via Yadnarie assessed under the 'core' set of assumptions – with a new SA-NSW interconnector assumed

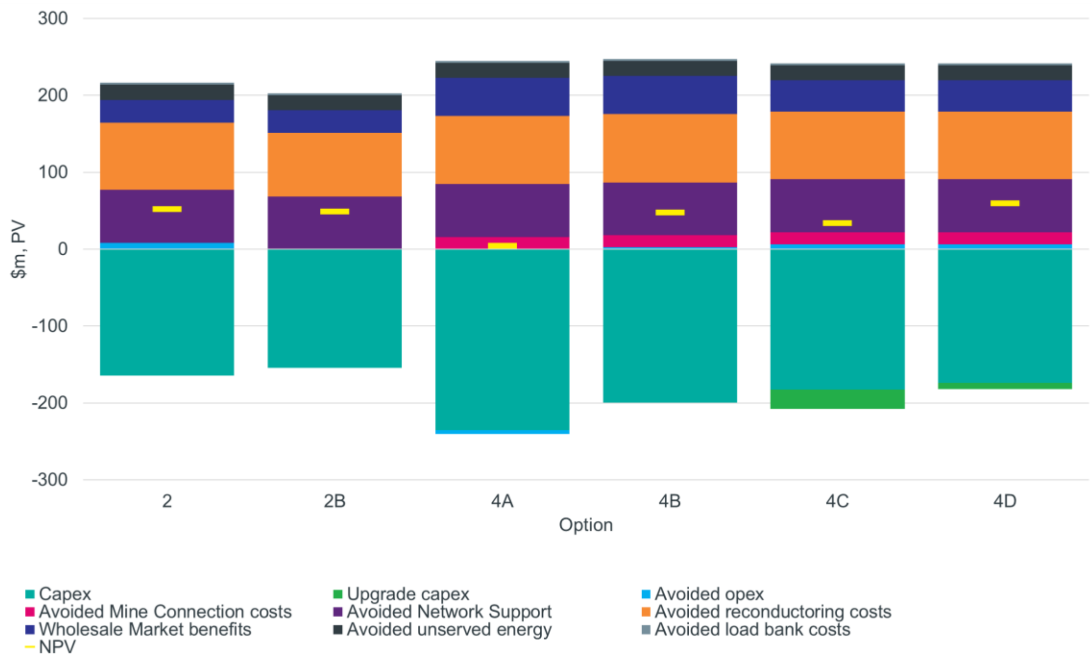
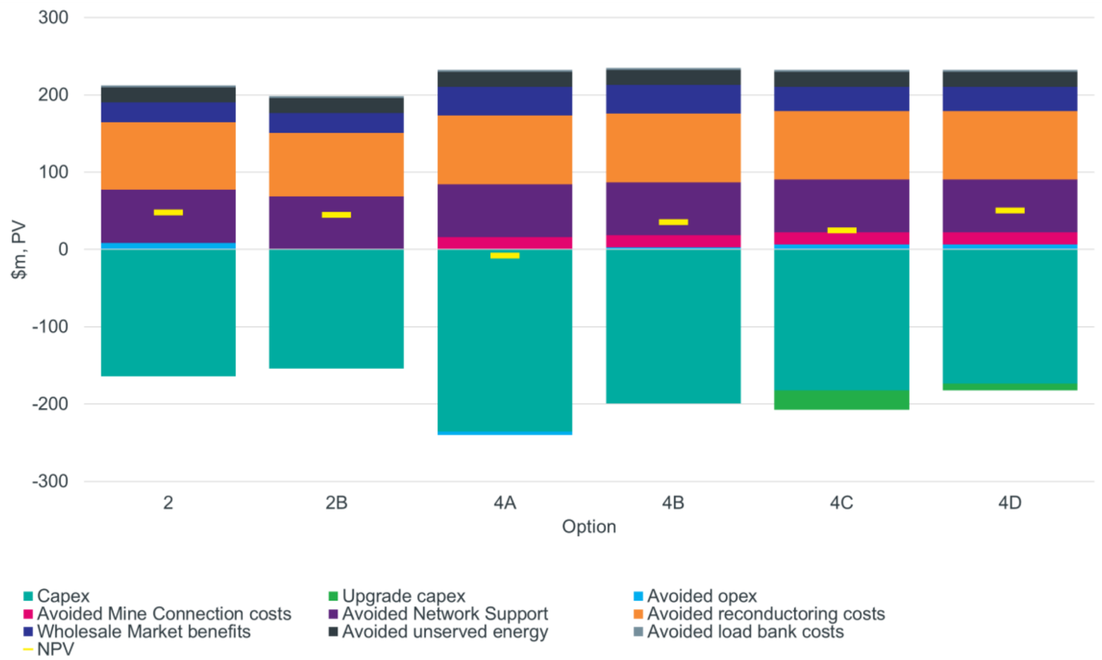


Figure 18 – Breakdown of estimated net market benefits for credible options going via Yadnarie assessed under the 'core' set of assumptions – with no new SA-NSW interconnector assumed



The three figures below show the overall estimated net market benefit for each option that involves new lines going via Wudinna and the breakdown of costs and benefits. All of these options (with the exception of Option 3B) are found to have significant negative net market benefits.

Figure 19 – Summary of estimated net market benefits for the credible options going via Wudinna assessed under the 'core' set of assumptions

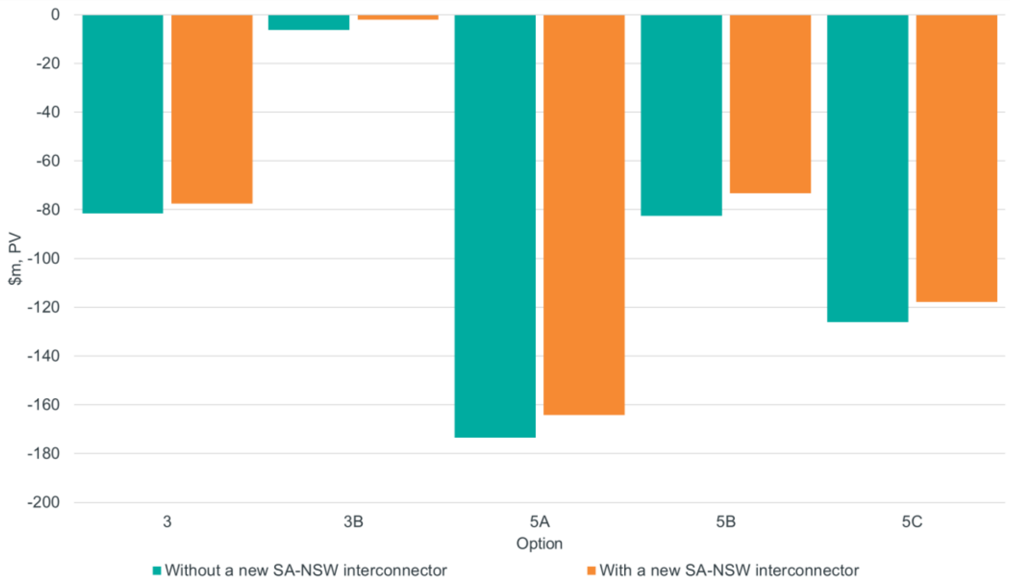


Figure 20 – Breakdown of estimated net market benefits for credible options going via Wudinna assessed under the 'core' set of assumptions – with a new SA-NSW interconnector assumed

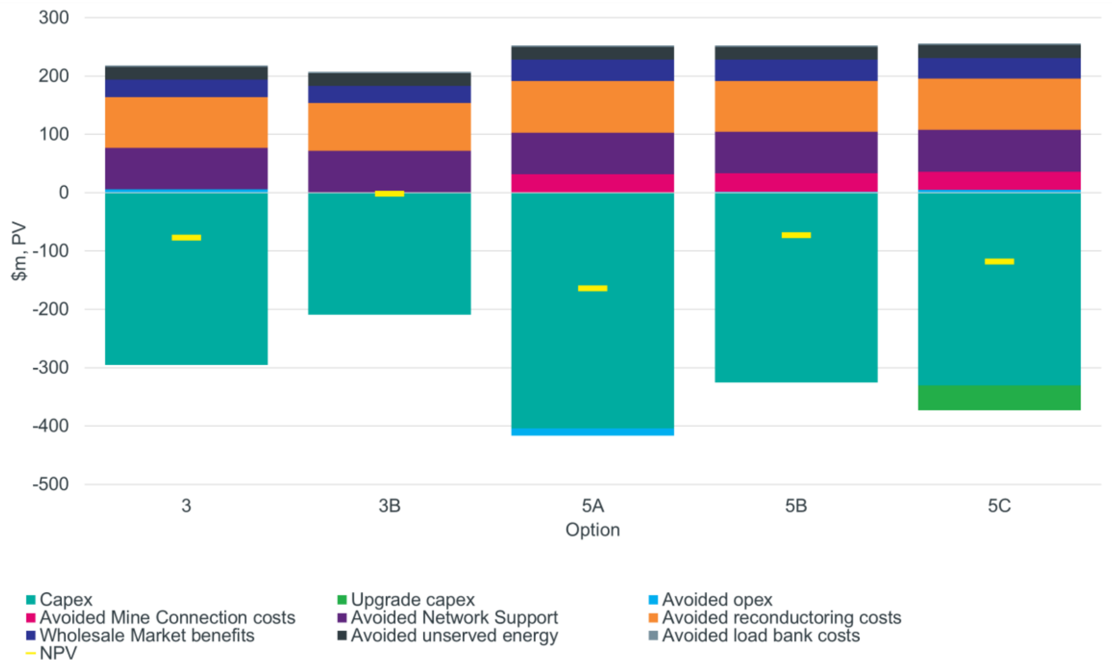
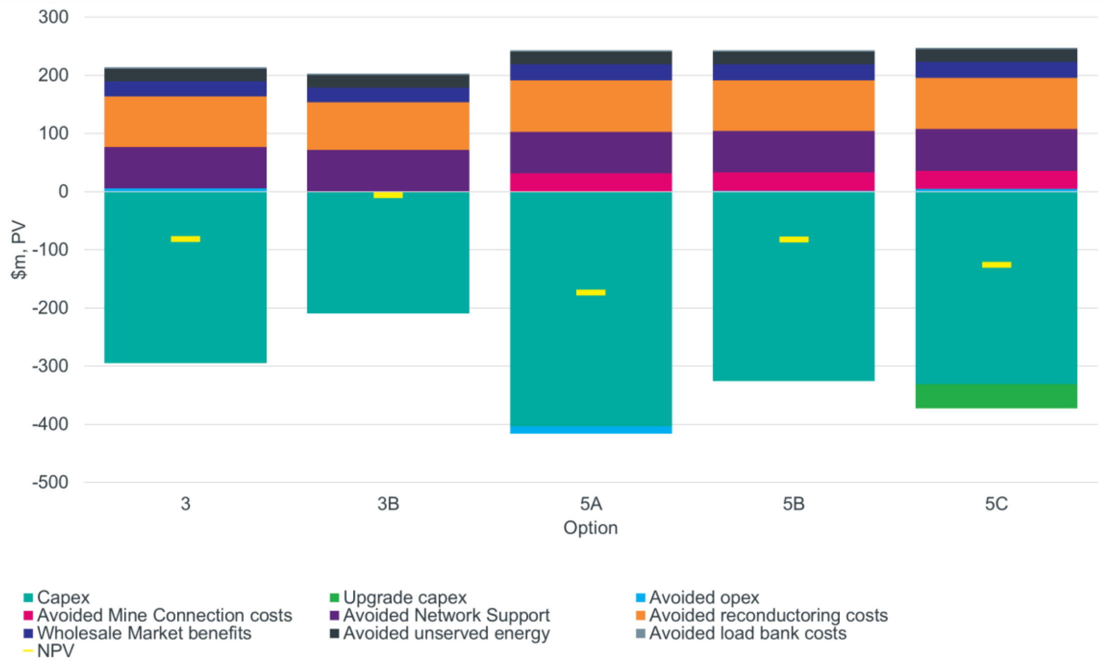


Figure 21 – Breakdown of estimated net market benefits for credible options going via Wudinna assessed under the 'core' set of assumptions – with no new SA-NSW interconnector assumed



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

- all the options considered provide market benefits in terms of increased reliability, and therefore decreased unserved energy, for customers on the Eyre Peninsula
- all options provide a substantial benefit associated with the avoided network support costs associated with maintaining the required ETC reliability standard at Port Lincoln – this avoided cost is, however, substantially the same for all credible options, relative to the base case (Option 1) and so does not affect the ranking of the options
- there are expected to be lower transmission costs associated with connecting new mining load to the electricity network for options that result in all, or part, of the Eyre Peninsula being operated at 275 kV capacity
- there are negligible benefits stemming from any impact on the wholesale electricity market by facilitating *new* wind generation locating on the Eyre Peninsula – this is a key change from the PADR and is due to an updated assessment of the relative wind resource quality on the Eyre Peninsula undertaken by AEMO as part of the ISP.

While wholesale market benefits have reduced significantly from the PADR on account of limited forecast investment in new wind generation on the Eyre Peninsula, the assessment still finds a material benefit associated with relieving the constraints on and reducing losses for existing wind farms on the Eyre Peninsula.

Other findings include:

- Option 4D is the top-ranked option as it introduces flexibility and saves costs upfront by operating the Cultana to Yadnarie section at 132 kV until new mining load triggers conversion to 275 kV
- the additional cost of going via Wudinna is found to be greater than the additional benefits this delivers, i.e., Options 3 and 3B and Options 5A-5C
- the new variant of Option 2, developed in response to submissions to the PADR, that involves reconductoring sections of the existing line (Option 2B) is found to provide slightly reduced positive net market benefits than the original Option 2, while the additional cost of such an option going via Wudinna (Option 3B) results in marginally negative net market benefits
- Option 4B (with no flexibility) has higher costs than Option 4D (due to the Cultana to Yadnarie route being built and operated to 275 kV from the start), and so provides less net market benefits
- the costs of also providing flexibility to later upgrade the Yadnarie to Port Lincoln section to 275 kV (Option 4C) was not found to be justified by the potential additional benefits.

9.3 The net benefits over and above a ‘do nothing’ base case

The figure below compares all options, including Option 1, relative to a ‘do nothing’ base case. In particular, the ‘do nothing’ base case reflects no new capital expenditure and a reliance on increasing reactive maintenance and network support, with no reconductoring of the existing line.

Figure 22 – Summary of estimated net market benefits for all credible options, relative to a 'do nothing' base case

The figure shows that Option 4D has net market benefits of around $140 million over 20 years (in PV terms) relative to a 'do nothing' base case with no new SA-NSW interconnector assumed, which is approximately $50 million more than reconductoring the existing line and renewing a network support contract at Port Lincoln.

In the case where there is a new SA-NSW interconnector is assumed, Option 4D has net market benefits of around $149 million relative to the 'do nothing' base case, approximately $60 million in excess of the benefits from reconductoring the existing line and renewing a network support contract at Port Lincoln.

The approximate $90 million of net benefit associated with Option 1 is to be treated as indicative only and reflects the net benefits of reconductoring sections of the existing transmission line and establishing a new backup generation network support arrangement at Port Lincoln estimated as part of ElectraNet's 2018-23 Revenue Proposal, adjusted for inflation. Further details of the economic case underpinning Option 1 were presented in Appendix F of the Project Assessment Draft Report.

In addition, the wholesale market modelling has not been separately undertaken for the assessment of a 'do nothing' base case. This assessment has been included for illustrative purposes and includes the results of the market modelling undertaken for Options 2-5C but does not separately estimate the wholesale market impacts of assuming a 'do nothing' base case (which are instead based on previous analysis undertaken by ElectraNet as part of its earlier revenue proposal to the AER).

9.4 An increase in the assumed national emission reduction

The benefits of all options increase significantly under the assumption of a higher national emission reduction commitment. In particular, if an increase in the emission reduction required by 2030 to 52 per cent is assumed, consistent with the ISP's strong scenario, the estimated net market benefits increase for all options, irrespective of whether a new interconnector is built.

Figure 23 – The difference in the estimated net market benefits with a higher national emissions policy

Under the assumption that no new interconnector is built, Option 4D remains the preferred option with an estimated net market benefit of $66 million (a 32 per cent increase on the 'core' estimate). In this case, the higher emissions target leads to investment in new renewable generation on the Eyre Peninsula being brought forward to contribute towards meeting this higher target. For example, under assumptions of neutral demand and gas prices and no mining load, the modelling projects approximately 250MW in new investment in solar PV on the Eyre Peninsula by 2030 for Option 4B, compared no new investment by 2030 in the lower emissions target case.[66]

When a new interconnector is assumed to be built, Option 4B becomes slightly preferred over Option 4D (net market benefits of $100 million and $91 million, respectively) under the higher assumed national emissions reduction. This is driven by Option 4B being able to accommodate more generation on the Eyre Peninsula earlier on in the assessment period (as it is operated at 275 kV initially) and that, in the absence of mining loads, Option 4D does not result in the network being upgraded (and so has lower capacity and higher losses).

[66] A similar result occurs under the preferred option, Option 4D, however, it is difficult to provide a simple comparison for this set of assumptions owing to the interaction between network upgrade decisions and mining loads under this option.

The relatively large increase in benefits for Options 4B and 4D in the presence of the interconnector (and the higher national emissions reduction policy) is primarily driven by increased output from existing wind farms on the Eyre Peninsula and the option to build on the Eyre Peninsula leading to avoided costs associated with constructing new transmission infrastructure and new generation in REZs across the NEM. With the interconnector, increased output from existing plants and new renewable generation is able to substitute for generation in other regions and therefore has higher value to the market.

9.5 The results are robust to the assumed likelihood of mining load

The results are found to be robust to the underlying assumptions regarding the likelihood that new mining developments will come to fruition on the Eyre Peninsula over the next 20 years.

We sought independent advice from mining advisory firm AME Research on the likelihood of the various potential mining developments on the Eyre Peninsula progressing.

As outlined in section 7.4, AME is of the view that there is a greater than 50 per cent chance of Iron Road coming online over the next 15 years (equivalent to an approximate annual likelihood of 5.8 per cent). AME considers that the other potential mining loads on the Eyre Peninsula are not expected to come online over this period (and has effectively assumed they have a zero probability, which has been reflected in the core modelling results in this PACR).

The magnitude of the estimated net market benefits are found to be sensitive to these underlying assumed likelihoods. The two figures below illustrate the three key mining sensitivities we have investigated assuming the case where no new interconnector is built and the case where a new interconnector is built, respectively.

Figure 24 – Change in net market benefits estimated assuming different likelihoods for mining – with no new SA-NSW interconnector assumed

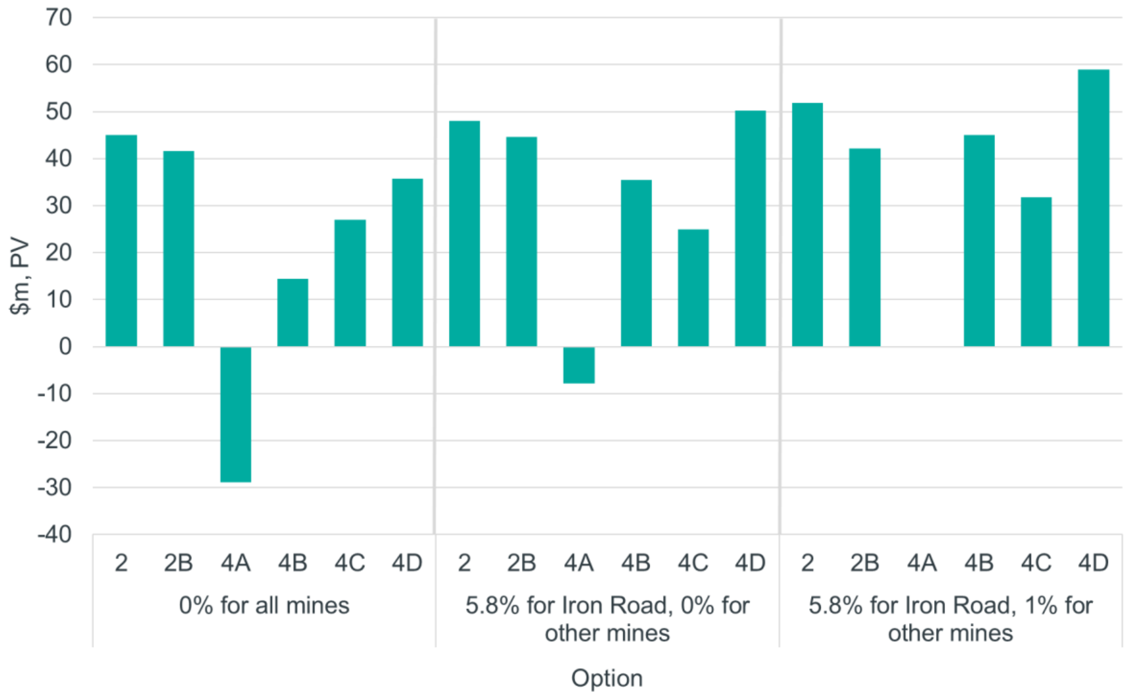
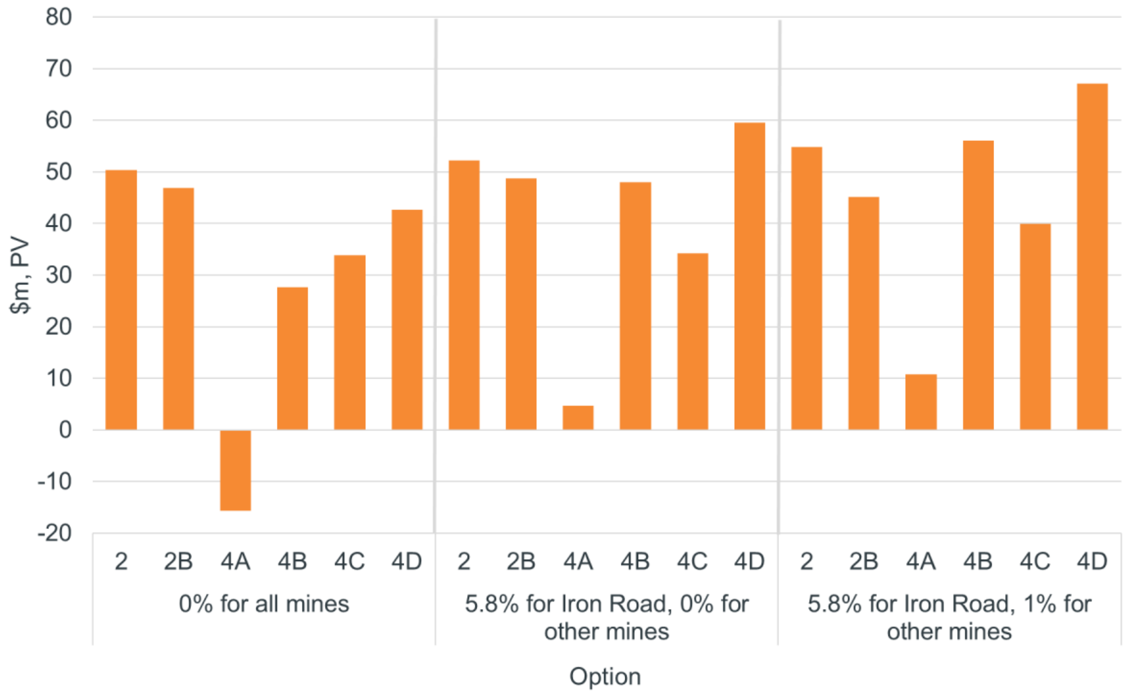


Figure 25 – Change in net market benefits estimated assuming different likelihoods for mining – with a new SA-NSW interconnector assumed



While Option 4D is the top-ranked option under the core assumptions, it becomes even more preferred if the other mining developments (i.e. other than Iron Road) are given a positive probability of developing over the assessment period.

As an example, keeping all 'core' assumptions constant but increasing the likelihood that the other mining loads will develop to 1 per cent per year, increases the estimated net market benefits associated with Option 4D from approximately $50 million to $59 million if no new SA-NSW interconnector is built, and $60 million to $67 million if a new SA-NSW interconnector is built.

We therefore consider that the core estimates of approximately $50 million and $59 million in net market benefits for Option 4D to be lower bounds on the actual expected net market benefits from this option, in terms of these other mining loads developing on the Eyre Peninsula (since there is primarily upside opportunity to the assumed likelihood of these mines developing).

The assessment finds that Option 4D remains the preferred option even if the likelihood that Iron Road will develop is assumed to be 4.4 per cent per year in the case where no new interconnector is built (this assessment keeps the likelihood of the other mining developments at 0 per cent), which is substantially below the AME assessment of 5.8 per cent per year.[67] Moreover, if a new interconnector is built, the likelihood that Iron Road would develop has to fall to below 2.5 per cent per year for Option 4D to no longer be preferred.

In addition, the assessment finds that, even if Iron Road is assumed to not develop over the assessment period (and neither are the other developments), Option 4D is still estimated to have positive net market benefits. Under these assumptions, Option 4D has an estimated net market benefits of $36 million, and is ranked behind Options 2 and 2B (which have higher estimated net market benefits of $45 million and $42 million, respectively). In addition, if a new interconnector is assumed to be built under these assumed mining likelihoods, Option 4D has an estimated net market benefit of $43 million, ranked behind Options 2 and 2B which have higher estimated net market benefits at $50 million and $47 million, respectively.

These findings demonstrate that the preferred option is robust to the assumed likelihood of new mining developments or other demand increases in the future.

9.6 An increase in network support costs at Port Lincoln

A key benefit of all options, relative to Option 1, comes in the form of reduced operating costs associated with maintaining a network support agreement at Port Lincoln to meet the ETC reliability requirements. These costs are in the order of $8 million/year and are paid for by electricity customers in South Australia.

The figure below shows the estimated net market benefits assuming both a 30 per cent lower and 30 per cent higher annual network support cost. Under both a lower and higher assumed annual network support cost, Option 4D remains the preferred option.

[67] Assuming a 4.4 per cent annual likelihood for Iron Road under the 'core' assumptions, and a zero probability for other developments, results in Option 4D and Option 2 having equal estimated net market benefits (of $47.5 million).

Figure 26 – Change in net market benefits estimated assuming higher and lower annual network support costs

While we do not consider the low sensitivity to be realistic, given our recent negotiations regarding a new network support contract, our assessment shows that, under the core assumptions, the annual cost would need to fall by approximately 73 per cent in order for Option 1 to be preferred in the case where no new SA-NSW interconnector is built. Where a new interconnector is assumed to be built, network support costs would need to fall by approximately 83 per cent in order for Option 1 to be the preferred option.

9.7 General sensitivities to core assumptions

Sensitivity analysis has also been undertaken to test the robustness of the RIT-T assessment to several other key assumptions. Each of these is discussed in-turn below.

As outlined in the PADR, we have not undertaken sensitivities of assumptions feeding into estimated reductions in involuntary load shedding (e.g. the VCR) or changes in transmission losses.[68]

As shown above, these categories are found to be immaterial in differentiating between credible options. Any increase in VCRs to account for the wide area impacted by transmission line outages would marginally increase the benefits of all new transmission line options compared to Option 1.

[68] In addition, while the PADR also investigated the assumption that mining developments on the Eyre Peninsula elect to source their energy requirements from the grid, we have not done so in the PACR. This is because it was found to not affect the identification of the preferred option at the PADR stage and there is no reason to believe this would have changed since then.

9.7.1 Assumed gas prices and electricity demand

To understand the effect of forecasts for electricity demand and gas prices on the calculation of market benefits, we have conducted sensitivity analysis on the assumed demand and gas price forecasts.

For each of the strong, neutral and weak gas price forecasts and whether the new SA-NSW interconnector is built or not, Option 4D remains the preferred option. This is illustrated in the figure below.

Figure 27 – Change in net market benefits estimated under high, neutral and low gas prices

The figure below shows the net benefits under strong, neutral and weak AEMO ISP demand forecasts. Unlike the results for gas price forecasts, the value of net benefits does not exhibit a linear relationship with the level of demand.

Option 4D remains the preferred option under all demand sensitivities but is ranked effectively equally with Option 2 under the weak demand sensitivity with no new SA-NSW interconnector.

For each of the demand sensitivities that we have investigated, Option 4D has positive net market benefits.

Figure 28 – Change in net market benefits estimated under high, neutral and weak demand forecasts

9.7.2 Assumed capital costs

As outlined in section 8.1 (and Appendix I), the transmission capital cost component of each option has been revised since the PADR. This has resulted in minor changes to the overall estimated costs and reflects the cost of each option being estimated to a greater degree of accuracy than in the PADR.

We have investigated the impact of changes in capital costs for all options relative to Option 1. However, as there is no reason to expect the accuracy of the current cost estimates to differ between options, and given the magnitude of benefits compared to these cost estimates, these sensitivities even at plus 15 per cent were not found to affect the finding of the RIT-T, that Option 4D is the preferred option (and has positive net market benefits).[69]

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[69] While a +/- 25 per cent sensitivity was run on estimated capital costs in the PADR, we have run a +/-15 per cent in the PACR on account of the capital costs being refined and estimated to a higher degree of certainty than in the PADR.

Figure 29 – Sensitivity of net market benefits estimated to the assumed capital costs

We further stress-tested the results and found that capital costs for Option 4D would have to increase by approximately 29 per cent for it to no longer be expected to have positive net market benefits in the case where no new interconnector is built. Where a new interconnector is assumed to be built, this increases to approximately 34 per cent.

9.7.3 Assumed discount rate

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 ‘core’ discount rate assumption of 6 per cent
- a low discount rate of 3.62 per cent.

While the magnitudes of estimated net market benefits, in present value terms, are found to vary with the underlying discount rate, Option 4D is always found to be the preferred option.

Figure 30 – Sensitivity of net market benefits estimated to the assumed discount rate

10. Preferred option and customer price impact

The RIT-T assessment undertaken and presented in this PACR concludes that Option 4D is the preferred option that simultaneously ensures reliable electricity supply to the Eyre Peninsula going forward, consistent with the ETC reliability standards, and delivers the most efficient long-term solution.

Option 4D initially involves:

- building new double-circuit 275 kV lines from Cultana to Yadnarie (about 142 km) – lines to be initially operated at 132 kV;
- building new double-circuit 132 kV Yadnarie to Port Lincoln (about 130 km);
- establishing an additional 132 kV exit at Cultana substation;
- establishing two additional 132 kV exits at Yadnarie substation; and
- establishing an additional 132 kV exit at Port Lincoln Terminal substation.

The future incremental capital works of moving from 132 kV operation to 275 kV operation for the Cultana to Yadnarie section involve the following components:

- two new 275 kV exits at Cultana; and
- a new 275/132 kV yard including transformers at Yadnarie West.

This conclusion differs from the draft finding of this RIT-T presented in the PADR. In particular, the preferred option in the earlier PADR was a 'set and forget' option comprising a double-circuit 275 kV line between Cultana and Yadnarie, and a double-circuit 132 kV line between Yadnarie and Port Lincoln ('Option 4B').

The final conclusion of this RIT-T that Option 4D is the preferred option represents a more flexible variant of this earlier option, under which the section between Cultana and Yadnarie would be built to 275 kV but operated at 132 kV until additional capacity is needed; e.g. to accommodate the commitment of new mining load on the Eyre Peninsula.

The change in the preferred option since the PADR is primarily due to:

- recent modelling by AEMO for the ISP, that found no material difference in wind capacity factors between the Eyre Peninsula and the Mid North region of South Australia, substantially reducing the wholesale market benefits associated with higher capacity options; and
- a refinement of the option value modelling applied[70], which now better captures the benefits associated with flexible options

In the event such commitment occurs prior to completion of construction, then this option would be operated at 275 kV from the start as part of the preferred option, and would therefore be the same as Option 4B.

[70] 'Option value' for the Eyre Peninsula arises through the ability to stage decisions regarding operating voltages of the transmission network. As part of the initial decision, ElectraNet can decide whether to build transmission lines with a higher rating, ie, 275 kV, but to operate them at 132 kV, thereby deferring capital expenditure associated with installing 275 kV substations, and only incurring it in circumstances where it would be beneficial to do so.

However, if there is no commitment of mining load, then the costs associated with the substation components of Option 4B would be avoided until such time as required to accommodate mining development, thus lowering the upfront costs to customers.

If a new mining load or other significant load connects in future, the further upgrade works to enable operation of the Cultana to Yadnarie line at 275 kV would be funded by customers generally. However, depending on its actual size, the new significant load would bear a significant portion of both locational and wider components of transmission charges, resulting in an overall reduction of transmission charges to other customers.

The PACR conclusion has been found to be the case for not only a central 'core' set of key assumptions but also for a range of alternate underlying assumptions regarding the future 'state of the world', as well as under numerous sensitivity tests on other key modelling assumptions.

Option 4D has been found to be the preferred credible option in the vast majority of sensitivities and alternate scenarios investigated and, in all cases, was found to deliver net market benefits.

Customer price impact

The capital cost of the preferred option is estimated to be $240 million, which is approximately $160 million more than the cost of reconductoring sections of the existing transmission line.

However, the preferred option would remove the need for the backup network support arrangement and therefore save ongoing operating costs of about $8 to $9 million per year, which are paid for by electricity customers in South Australia.

Option 4D is estimated to deliver net market benefits of around $150 million over 20 years (in PV terms) relative to a 'do nothing' base case, and approximately $60 million more than reconductoring the existing line and renewing a network support contract at Port Lincoln (assuming a new SA-NSW interconnector is in place in both cases).

The cost of the new transmission line is offset by saving customers the cost of replacement works on the existing line and ongoing network support costs of $8 to $9 million per year. Because of this, the preferred option has a negligible impact on the transmission component of the annual electricity bill for the average residential customer in South Australia – estimated to be around 10 cents per year.

Initial construction is expected to take three years, with commissioning possible by the end of 2021, subject to obtaining necessary environmental and development approvals. The future incremental capital works of moving from 132 kV operation to 275 kV operation centre on substation works[71] and are expected to take two years to complete.

Option 4D is unlikely to have a material inter-regional impact.[72]

We are confident that this PACR, the accompanying detailed analysis and the preferred option satisfy the RIT-T.

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[71] At the Cultana and Yadnarie substations.

[72] As determined by reference to AEMO's screening test (as presented in section 4.7 of the PSCR).

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APPENDICES

Appendix A 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 National Electricity Rules (NER) version 110.

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
5.16.4(k)	The project assessment draft report must include:	-
	(1) a description of each credible option assessed;	5 & Appendix D
	(2) a summary of, and commentary on, the submissions to the project specification consultation report;	Appendix E
	(3) a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;	5, 8 & Appendix F
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	6, 7, 8 & Appendices F & G
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	6 & Appendix F
	(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);	9
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	9
	(8) the identification of the proposed preferred option;	10
	(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*.	10

Appendix B Definitions

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

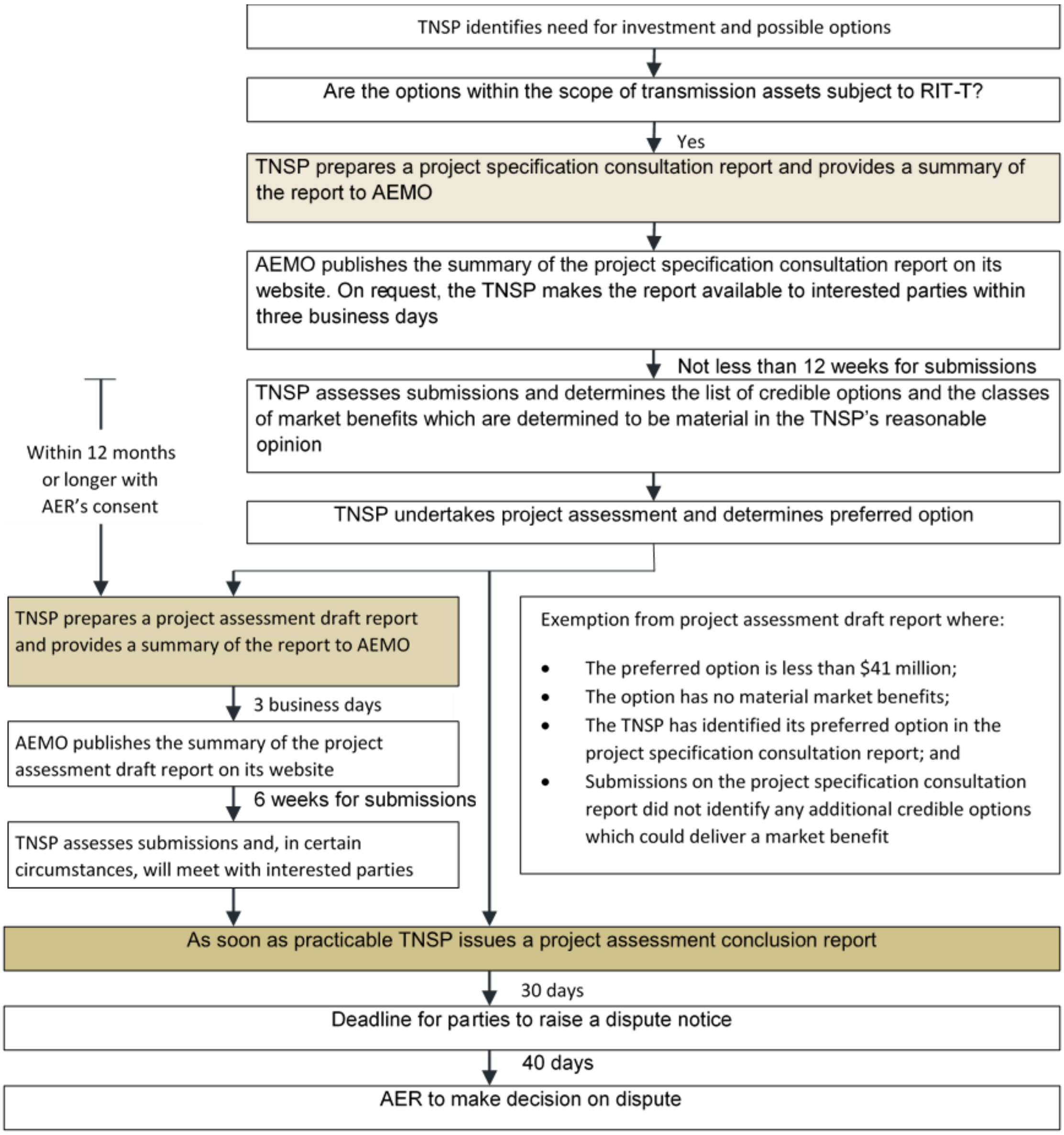
A comprehensive list of applicable regulatory instruments is provided in the Rules.

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 C 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 31 – Key policy and regulatory developments since release of the PSCR



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

Appendix D Further detail on credible options assessed

This appendix details the key components of each of the credible options assessed in this PACR.

While the network diagrams in this appendix highlight the location of both potential Iron Road mining load, as well as a range of 'other' indicative mining loads on the peninsula, only the Iron Road loads have been assumed as possible over the assessment period (as discussed in section 7.4 above). The 'other' potential loads have only been assumed in the sensitivity regarding mining developments on the peninsula (as outlined in section 9.5 above).

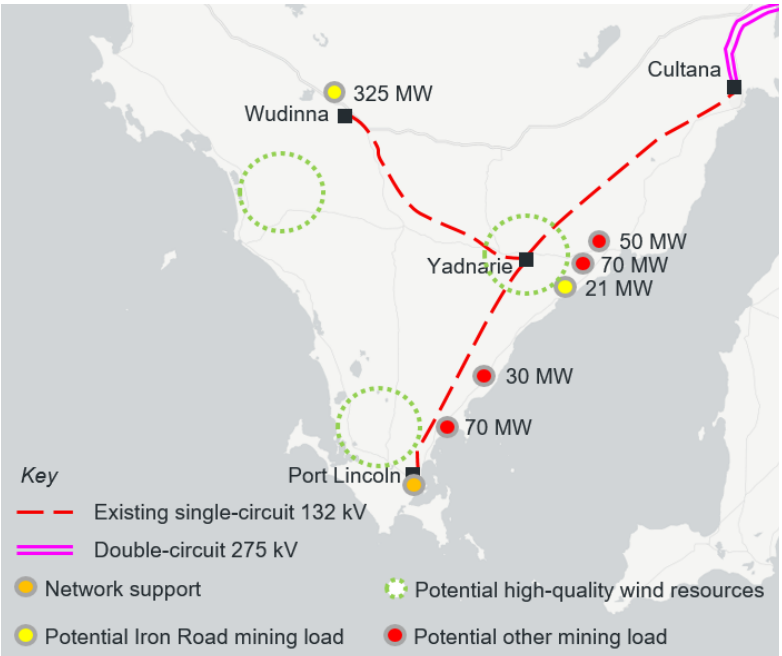
D1 Option 1 – Continue network support at Port Lincoln and reconductor sections of the existing 132 kV single-circuit line ('base case')

This option involves continuing to meet the Port Lincoln ETC reliability standards by using a combination of transmission infrastructure and network support at Port Lincoln.

Option 1 involves live-line reconductoring of four sections (totalling 118 km) of the existing 132 kV network. It also involves the continuation of a network support agreement at Port Lincoln, which could be an extension of existing arrangement or a new contract with a third party.

The figure below illustrates the high-level network configuration under Option 1, as well as the locations of key mining and wind potential on the Eyre Peninsula. Due to the limited capacity of the network under this option, no additional mining load or wind generation can connect on the Eyre Peninsula.

Figure 32 – Network configuration under Option 1, as well as locations of key mining and wind potential



The reconductoring work on the existing 132 kV line will require additional generation support from Port Lincoln during construction, in order to maintain supply to Port Lincoln, Yadnarie, Wudinna, and Middleback.

Capital costs for the reconductoring works are estimated to be in the order of $80 million. Reconductoring is expected to take 2 years, with commissioning possible by the end of 2020, subject to obtaining necessary environmental and development approvals.

Additional capital costs to reconductor the remaining sections of the 132 kV line are estimated to be in the order of $90 million, expected around 2033.

Capital costs to replace the existing Yadnarie substation based on condition are estimated to be in the order of $25 million, expected around 2037.

This option requires a 5 MW load bank to be installed at Port Lincoln in each of 2019, 2025, 2030, 2030, at an estimated capital cost of $2.9 million each.

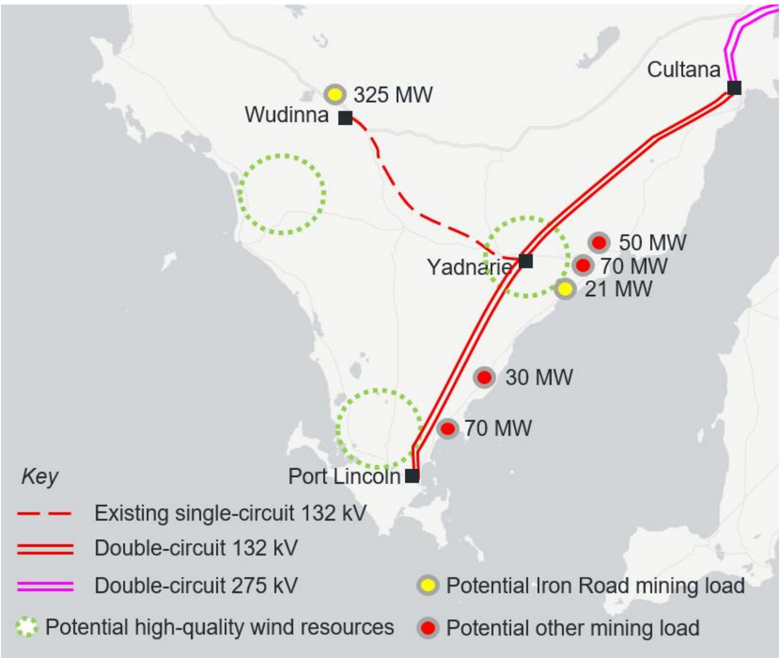
We released a RFT on 28 September 2017 that requested financial and operating parameters from network support proponents, including from proponents that submitted to the PSCR. We have assessed these responses and developed assumptions regarding future network support costs at Port Lincoln for Option 1.

D2 Option 2 – Double-circuit 132 kV

This option involves construction of a double-circuit 132 kV line following a Cultana to Yadnarie and Yadnarie to Port Lincoln route.

The figure below illustrates the high-level network configuration under Option 2, as well as the locations of key mining and wind potential on the Eyre Peninsula. Since this option does not involve a 275 kV line, it cannot support additional mining load and, should any of the mining scenarios eventuate, then it is assumed that they would need to source their energy by connecting back to the 275 kV network at Cultana. In addition, the existence of double-circuit 132 kV lines on the Eyre Peninsula means that additional wind can locate on the Eyre Peninsula.

Figure 33 – Network configuration under Option 2, as well as locations of key mining and wind potential



This option would utilise additional easements on the Eyre Peninsula that ElectraNet has already acquired.

This option would involve additional generation support during construction, although it would be less than for Option 1 since it would only essentially be required for a short time, that is, when switching supply over to the new line.

Capital costs to replace the existing Yadnarie substation based on condition are estimated to be in the order of $20 million, expected around 2037.

Capital costs for this option are estimated to be in the order of $225 million. Construction is expected to take 2 years, with commissioning possible by the end of 2021, subject to obtaining necessary environmental and development approvals.

This option requires a 5 MW load bank to be installed at Port Lincoln in 2019, at an estimated capital cost of $2.9 million.

D3 Option 2B – Single-circuit 132 kV with reconductoring of the existing line

Option 2B is a new lower capacity option introduced since the PADR in response to submissions received.

Option 2B involves reconductoring sections of the existing line and building a new 132 kV line on a separate easement from Cultana to Port Lincoln, via Yadnarie.

Option 2B has essentially the same high-level network configuration as shown for Option 2 in the preceding section.

This option would utilise additional easements on the Eyre Peninsula that ElectraNet has already acquired.

As with Option 2, this option would involve some generation support during construction, although it would be less than for Option 1 since it would only essentially be required for a short time, that is, when switching supply over to the new line.

Capital costs for this option are estimated to be in the order of $215 million.[73] Construction is expected to take five years, with commissioning possible by the end of 2023, subject to obtaining necessary environmental and development approvals.

Additional capital costs to reconductor the remaining sections of the old 132kV line are estimated to be in the order of $25 million, expected around 2033.

Capital costs to replace the existing Yadnarie substation based on condition are estimated to be in the order of $20 million, expected around 2037.

This option requires a 5 MW load bank to be installed at Port Lincoln in 2019, at an estimated capital cost of $2.9 million.

D4 Option 3 – Two single-circuit 132 kV lines (one going via Wudinna)

This option involves construction of two single-circuit 132 kV lines from Cultana to Port Lincoln route, with one going via Yadnarie and another going via Wudinna.

The figure below illustrates the high-level network configuration under Option 3, as well as the locations of key mining and wind potential on the Eyre Peninsula.

Since this option does not involve a 275 kV line, it cannot support additional mining load and, should any of the mining scenarios eventuate, then it is assumed that they would need to source their energy by connecting back to the 275 kV network at Cultana.

As with Option 2, the existence of two single-circuit 132 kV lines on the Eyre Peninsula means that additional wind can locate on the Eyre Peninsula.

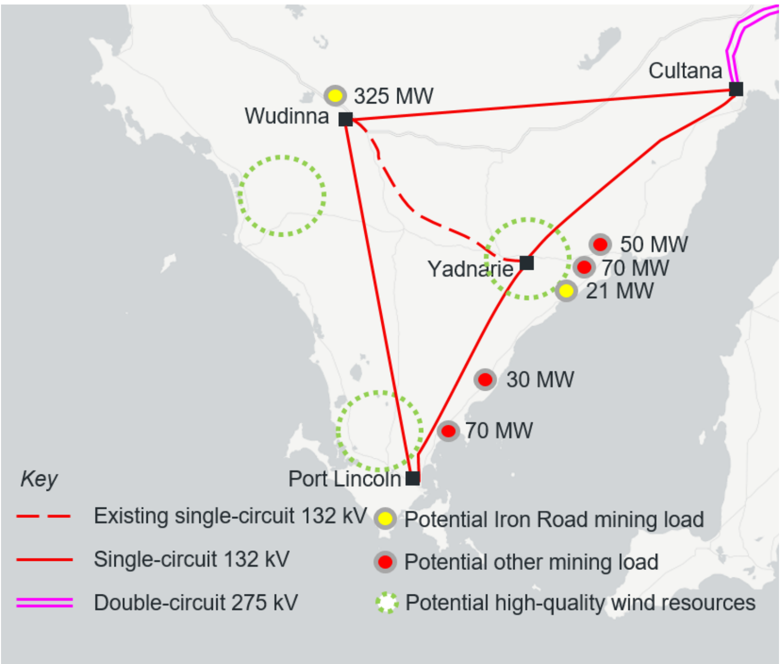
Under this option, the two new circuits would be constructed on geographically separated easements, sufficiently far apart to reduce the risk of outages from a single weather event.

This option would involve additional generation support during construction, which would be similar to Option 2 in magnitude since it would only essentially be required for a short time, that is, when switching supply over to the new lines.

Capital costs for this option are estimated to be in the order of $405 million. Construction is expected to take 5 years, with commissioning possible by the end of 2023, subject to land and easement acquisition and obtaining necessary environmental and development approvals.

73 Note that costs of the up-front and future reconductoring components of this option are lower than the reconductoring costs for Option 1. This is because construction of the new 132 kV lines would be completed before performing the required reconductoring works on the existing lines. Costs for generation support would then not be needed, as supply could be maintained through the new 132 kV lines while doing the reconductoring works, and a lower-cost methodology can be used for the reconductoring works.

Figure 34 – Network configuration under Option 3, as well as locations of key mining and wind potential



Capital costs to replace the existing Yadnarie substation based on condition are estimated to be in the order of $25 million, expected around 2037.

This option requires a 5 MW load bank to be installed at Port Lincoln in 2019, at an estimated capital cost of $2.9 million.

D5 Option 3B – Single-circuit 132 kV (via Wudinna) with reconductoring of the existing line

Option 3B is a new lower capacity option introduced since the PADR in response to submissions received.

Option 3B involves reconductoring sections of the existing line and building a new 132 kV line on a separate easement from Cultana to Port Lincoln, via Wudinna.

Option 3B has essentially the same high-level network configuration as shown for Option 3 in the preceding section.

As with Option 3, this option would require new easements going via Wudinna.

As with Option 2B, this option would involve some generation support during construction.

Capital costs for this option are estimated to be in the order of $295 million.[74] Construction is expected to take five years, with commissioning possible by the end of 2023, subject to obtaining necessary environmental and development approvals.

Additional capital costs to reconductor the remaining sections of the old 132kV line are estimated to be in the order of $25 million, expected around 2033.

Capital costs to replace the existing Yadnarie substation based on condition are estimated to be in the order of $25 million, expected around 2037.

D6 Option 4A – Double-circuit 275 kV lines

Option 4A has been included as a high-capacity 'set and forget' option where the entire double-circuit line is built and operated at 275 kV initially.

Option 4A has been included to investigate whether it is ever efficient to build and operate the entire double-circuit line to 275 kV initially – in particular, where it is expected that mining developments will come online with a high probability.

The figure below illustrates the high-level network configuration under Option 4A, as well as the locations of key mining and wind potential on the Eyre Peninsula.

The combination of new double-circuit lines and 275 kV capacity means that significant additional wind can locate on the Eyre Peninsula under Option 4A. In addition, the 275 kV capacity can support additional mining load associated with both the CEIP development and any other mining interests.[75]

This option would utilise the additional easements on the Eyre Peninsula that ElectraNet has already acquired.

This option would involve additional generation support during construction, although it would be less than for Option 1 since it would only essentially be required for a short time, that is, when switching supply over to the new line.

Capital costs for this option are estimated to be in the order of $330 million, which includes the full rebuild of Yadnarie substation to accommodate the new 275/132 kV transformation at that site.

Construction is expected to take 3 years, with commissioning possible by the end of 2021, subject to obtaining necessary environmental and development approvals.

This option requires a 5 MW load bank to be installed at Port Lincoln in 2019, at an estimated capital cost of $2.9 million.

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[74] Note that costs of the up-front and future reconductoring components of this option are lower than the reconductoring costs for Option 1. This is because construction of the new 132 kV lines would be completed before performing the required reconductoring works on the existing lines. Costs for generation support would then not be needed, as supply could be maintained through the new 132 kV lines while doing the reconductoring works, and a lower-cost methodology can be used for the reconductoring works.

[75] The exception to this is the 21 MW of load associated with the CEIP port facilities, which can be accommodated at Yadnarie.

Figure 35 – Network configuration under Option 4A, as well as locations of key mining and wind potential

D7 Option 4B – Double-circuit 275 kV between Cultana and Yadnarie and double-circuit 132 kV between Yadnarie and Port Lincoln

Option 4B has been included as a low cost 275 kV 'set and forget' option where the Cultana to Yadnarie double-circuit line is built and operated at 275 kV initially while the Yadnarie to Port Lincoln double-circuit line is built and operated at 132 kV (and cannot be upgraded to 275 kV later).

Option 4B considers the benefit of building and operating the top portion of the double-circuit line to 275 kV – in particular, where it is expected that CEIP will come online with a high probability.

The figure below illustrates the high-level network configuration under Option 4B, as well as the locations of key mining and wind potential on the Eyre Peninsula. The 275 kV capacity can support additional mining load associated with the CEIP development – should the other mining interests eventuate, then it is assumed that they would need to source their energy by connecting back to the 275 kV network at Cultana.[76] In addition, the combination of new double-circuit lines and 275 kV capacity (at the top) means that additional wind can locate on the Eyre Peninsula under Option 4B.

This option would utilise the additional easements on the Eyre Peninsula that ElectraNet has already acquired.

[76] The exception to this is the 21 MW of load associated with the CEIP port facilities, which can be accommodated at Yadnarie.

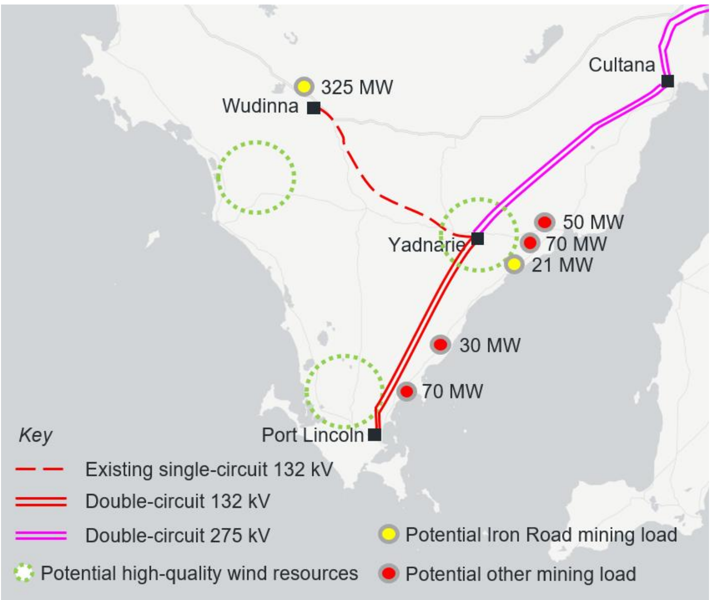
This option would involve additional generation support during construction, although it would be less than for Option 1 since it would only essentially be required for a short time, that is, when switching supply over to the new line.

Capital costs for this option are estimated to be in the order of $275 million, which includes the full rebuild of Yadnarie substation to accommodate the new 275/132 kV transformation at that site.

This option requires a 5 MW load bank to be installed at Port Lincoln in 2019, at an estimated capital cost of $2.9 million.

Construction is expected to take 3 years, with commissioning possible by the end of 2021, subject to obtaining necessary environmental and development approvals.

Figure 36 – Network configuration under Option 4B, as well as locations of key mining and wind potential



D8 Option 4C – Double-circuit 132 kV with the ability to be upgraded to 275 kV

This option is similar in route and build design to options 2, 4A and 4B with the main difference being that, while it is built to be able to operate at 275 kV if required, it is initially operated at 132 kV. Option 4C therefore allows the option of being able to upgrade the network capacity to 275 kV later, if it is efficient to do so.

The three figures on the next page illustrates the high-level network configuration under Option 4C, under each of the key 275 kV triggers. In particular, they demonstrate the flexibility in Option 4C compared to all other options (besides 4C and 5A) and the ability of its capacity and operation to be optimised if certain events happen in the future.

A key difference between Option 4C and Options 1, 2 and 3 is that it may result in 275 kV network capacity on part, or all, of the Eyre Peninsula in the future.

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This allows less costly connection to the transmission network for mines (i.e., as opposed to having to connect back to the 275 kV network at Cultana). It also means that more wind generation can locate on the Eyre Peninsula, both due to the greater capacity of a 275 kV line but also because mining load enables more wind to connect.

This option would utilise additional easements on the Eyre Peninsula that ElectraNet has already acquired.

This option would involve additional generation support during construction of a similar magnitude to Option 2, that is, only for a short time when switching supply over to the new line.

Capital costs for this option built to 275 kV but operated at 132 kV initially are estimated to be in the order of $250 million. The additional cost build associated with exercising the 'option' of upgrading the full network to 275 kV at a later date if mining and/or wind develop, is estimated as $80 million. If only the Cultana to Yadnarie section is upgraded to 275 kV operation, the upgrade cost is estimated as $40 million.

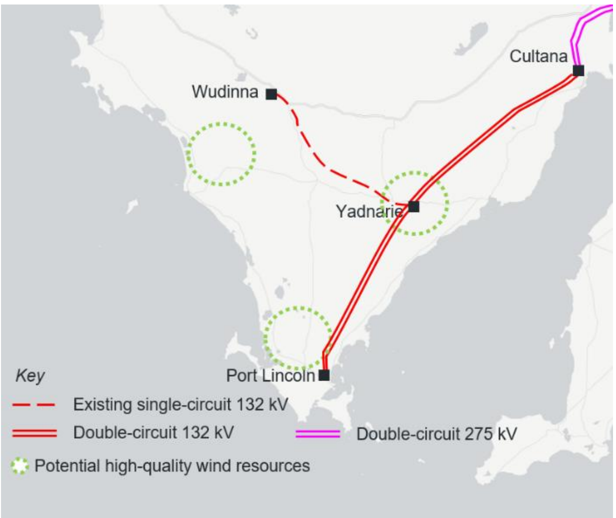
Capital costs to replace the existing Yadnarie substation based on condition (if it has not previously been addressed by the need to upgrade the operation of the Cultana to Yadnarie lines to 275 kV) are estimated to be in the order of $20 million, expected around 2037.

This option requires a 5 MW load bank to be installed at Port Lincoln in 2019, at an estimated capital cost of $2.9 million.

Initial construction is expected to take 3 years, with commissioning possible by the end of 2021, subject to land and easement acquisition and obtaining necessary environmental and development approvals. The future incremental capital works of moving from 132 kV operation to 275 kV operation centre on substation works[77] and are expected to take two years to complete.

[77] At the Cultana, Yadnarie and Port Lincoln substations.

Figure 37 – Network configurations possible under Option 4C

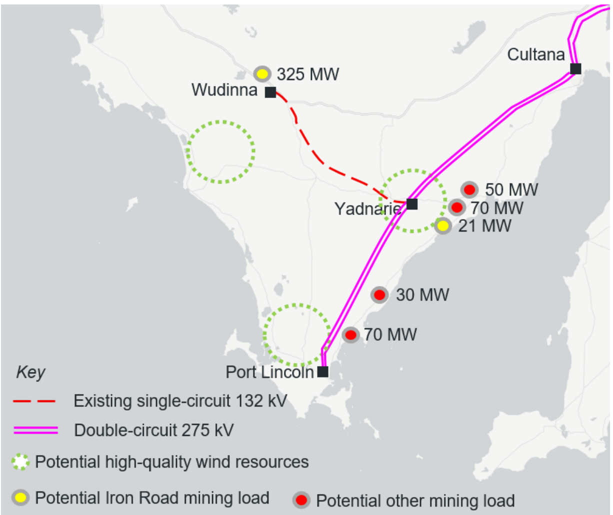


<u>Stage 1</u>

If no mining load commits or wind generation locates on the Eyre Peninsula then the entire double-circuit line will remain at 132 kV.

<u>Stage 2</u>

If Iron Road's CEIP reaches committed status, then ElectraNet will upgrade the Cultana to Yadnarie double-circuit section to 275 kV.



<u>Stage 3</u>

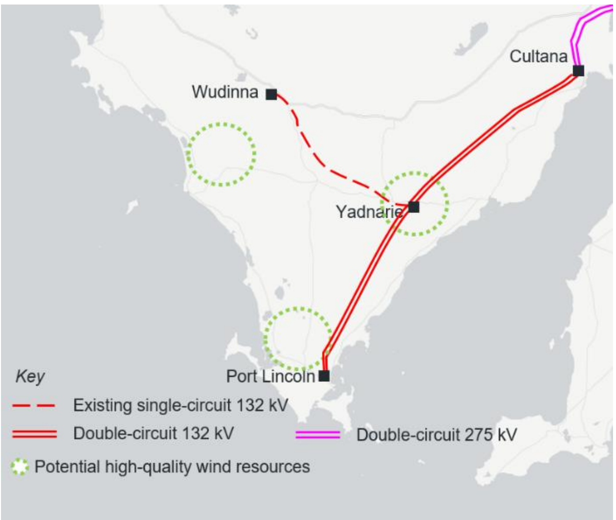
The entire length of new double-circuit lines will be upgraded to 275 kV if the CEIP project reaches committed status as do the other assumed mining loads.

D9 Option 4D – Double-circuit 132 kV with the ability for the Cultana to Yadnarie section to be upgraded to 275 kV

This option is similar in route and build design to options 2, 4A and 4B with the main difference being that, while it is initially operated at 132 kV, the top portion (i.e. from Cultana to Yadnarie) is built to be able to operate at 275 kV, if required. The remainder of the Eyre Peninsula (i.e. Yadnarie to Port Lincoln) is only ever built and operated at 132 kV. Option 4D therefore allows the option of being able to upgrade Cultana to Yadnarie network capacity to 275 kV later, if it is efficient to do so.

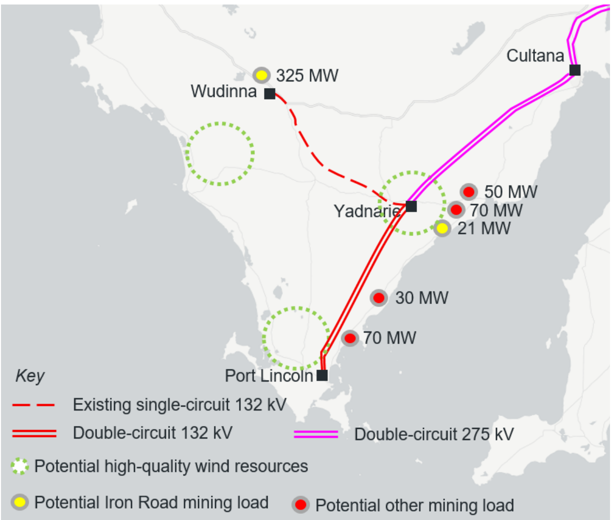
The two figures below illustrates the high-level network configuration under Option 4D, under each of the key triggers. In particular, they demonstrate the flexibility in Option 4D compared to all other options (besides 4C and 5C) and the ability of its capacity and operation to be optimised if certain events happen in the future.

Figure 38 – Network configurations possible under Option 4D



Stage 1

If no mining load commits or wind generation locates on the Eyre Peninsula then the entire double-circuit line will remain at 132 kV.



Stage 2

The Cultana to Yadnarie new double-circuit lines will be upgraded to 275 kV if Iron Road's CEIP project reaches committed status as do the other assumed mining loads.

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As with Options 4D and 5C, a key difference between Option 4D and Options 1, 2 and 3 is that it may result in 275 kV network capacity on part of the Eyre Peninsula in the future. This allows less costly connection to the transmission network for mines (i.e., as opposed to having to connect back to the 275 kV network at Cultana). It also means that more wind generation can locate on the Eyre Peninsula, both due to the greater capacity of a 275 kV line but also because mining load enables more wind to connect.

This option would utilise the additional easements on the Eyre Peninsula that ElectraNet has already acquired.

This option would involve additional generation support during construction of a similar magnitude to Option 2, that is, only for a short time when switching supply over to the new line.

Capital costs for this option built to 275 kV but operated at 132 kV initially are estimated to be in the order of $240 million. The additional cost build associated with exercising the 'option' of upgrading the Cultana to Yadnarie network to 275 kV at a later date if mining and/or wind develop, is estimated as $40 million.

Capital costs to replace the existing Yadnarie substation based on condition (if it has not previously been addressed by the need to upgrade the operation of the Cultana to Yadnarie lines to 275 kV) are estimated to be in the order of $20 million, expected around 2037.

This option requires a 5 MW load bank to be installed at Port Lincoln in 2019, at an estimated capital cost of $2.9 million.

Initial construction is expected to take 3 years, with commissioning possible by the end of 2021, subject to completion of land and easement acquisition and obtaining necessary environmental and development approvals. The future incremental capital works of moving from 132 kV operation to 275 kV operation centre on substation works[78] and are expected to take two years to complete.

D10 Option 5A – Two single-circuit 275 kV lines (one going via Wudinna)

Option 5A has been included as a high-cost/ capacity 'set and forget' option where both circuits are built and operated at 275 kV initially.

Option 5A has been included to investigate whether it is ever efficient to build and operate the both single-circuits at 275 kV initially – in particular, what probability of mining load would be required to justify this option.

The figure below illustrates the high-level network configuration under Option 5A, as well as the locations of key mining and wind potential on the Eyre Peninsula. The 275 kV capacity can support additional mining load associated with both the CEIP development and any other assumed mining interest. In addition, the 275 kV capacity means that significant additional wind can locate on the Eyre Peninsula under Option 5A.

Under this option, the two new circuits would be constructed on geographically separated easements, sufficiently far apart to reduce the risk of outages from a single weather event.

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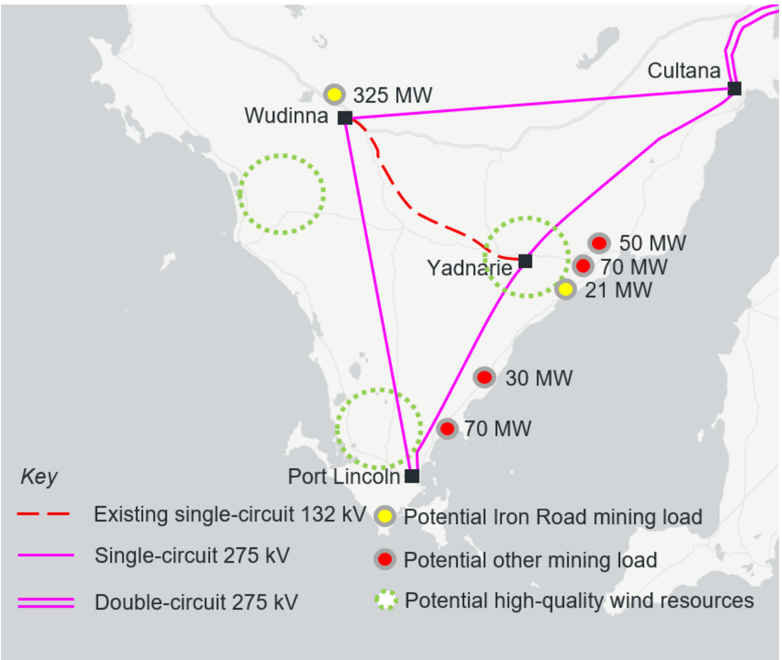
[78] At the Cultana and Yadnarie substations.

This option would involve additional generation support during construction, which would be like Option 2 in magnitude since it would only essentially be required for a short time, that is, when switching supply over to the new lines.

Capital costs for this option are estimated to be in the order of $560 million. Construction is expected to take 5 years, with commissioning possible by the end of 2023, subject to land and easement acquisition and obtaining necessary environmental and development approvals.

This option requires a 5 MW load bank to be installed at Port Lincoln in 2019, at an estimated capital cost of $2.9 million.

Figure 39 – Network configuration under Option 5A, as well as locations of key mining and wind potential



D11 Option 5B – Two single-circuit lines, with the Cultana to Wudinna line built and operated at 275 kV

Option 5B has been included as a ‘set and forget’ version where the Cultana to Wudinna single-circuit line is built and operated at 275 kV initially while the rest of the Eyre Peninsula is built and operated at 132 kV (and cannot be upgraded to 275 kV later).

Option 5B has been included to investigate whether it is ever efficient to build and operate the Cultana to Wudinna line to 275 kV initially – in particular, what probability of mining load would be required to justify this option.

The figure below illustrates the high-level network configuration under Option 5B, as well as the locations of key mining and wind potential on the Eyre Peninsula. The 275 kV capacity can support additional mining load associated with the CEIP development – should the other assumed mining interests eventuate, then it is assumed that they would need to source their energy by connecting back to the 275 kV network at Cultana.

In addition, the 275 kV line to Wudinna means that additional wind can locate on the Eyre Peninsula under Option 5B.

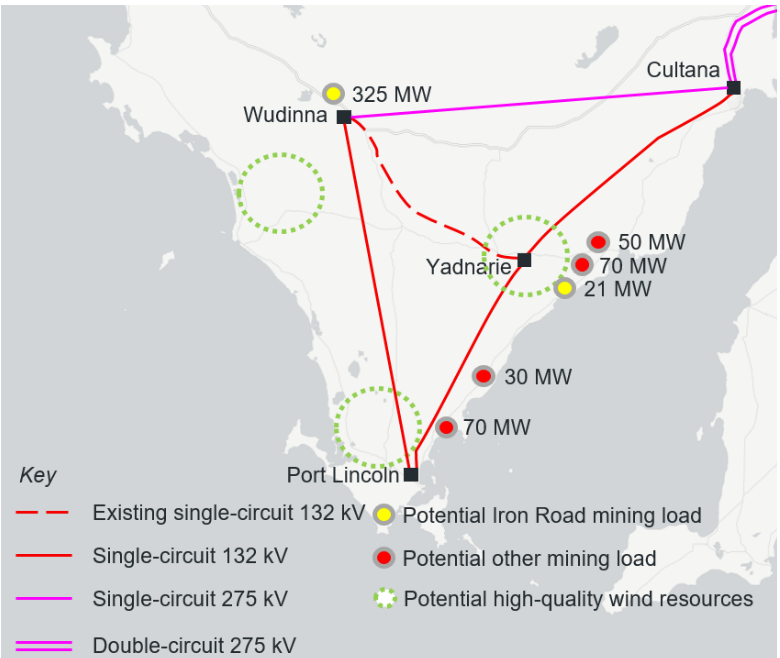
Under this option, the two new circuits would be constructed on geographically separated easements, sufficiently far apart to reduce the risk of outages from a single weather event.

This option would involve additional generation support during construction, which would be like Option 2 in magnitude since it would only essentially be required for a short time, that is, when switching supply over to the new lines.

Capital costs for this option are estimated to be in the order of $450 million. Construction is expected to take 5 years, with commissioning possible by the end of 2023, subject to land and easement acquisition and obtaining necessary environmental and development approvals.

This option requires a 5 MW load bank to be installed at Port Lincoln in 2019, at an estimated capital cost of $2.9 million.

Figure 40 – Network configuration under Option 5B, as well as locations of key mining and wind potential



D12 Option 5C – Two single-circuit 132 kV lines (one going via Wudinna) with the ability to be upgraded to 275 kV at a later date, if required

This option is similar in route and build design to options 3, 5A and 5B with the main difference being that, while it is built to be able to operate at 275 kV if need be, it is initially operated at 132 kV. Option 5C, like 4C and 4D, therefore allows the option of being able to upgrade the network capacity to 275 kV later, if its efficient to do so.

The four figures on the next page illustrates the high-level network configuration under Option 5C, under each of the key triggers.

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In particular, they demonstrate the flexibility in Option 5C compared to all other options (besides 4C and 4D) and the ability of its capacity and operation to be optimised if certain events happen in the future.

A key difference between Option 5C and Options 1, 2 and 3 is that it may result in 275 kV network capacity on part, or all, of the Eyre Peninsula in the future. This allows less costly connection to the transmission network for mines (i.e. as opposed to having to connect back to the 275 kV network at Cultana).

It also means that more wind generation can locate on the Eyre Peninsula, both due to the greater capacity of a 275 kV line but also because mining load enables more wind to connect.

Under this option, the two new circuits would be constructed on geographically separated easements, sufficiently far apart to reduce the risk of outages from a single weather event.

This option would involve additional generation support during construction, which would be like Option 2 in magnitude since it would only essentially be required for a short time, that is, when switching supply over to the new lines.

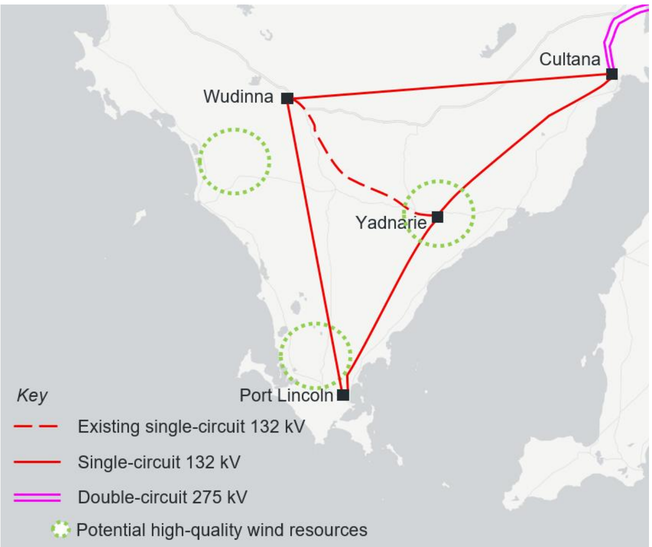
Capital costs for this option are estimated to be in the order of $455 million. The additional cost build associated with exercising the ‘option’ of upgrading the network (or part of it) to 275 kV at a later date if mining and/or wind develop, is estimated as $110 million.

This option requires a 5 MW load bank to be installed at Port Lincoln in 2019, at an estimated capital cost of $2.9 million.

Initial construction is expected to take 5 years, with commissioning possible by the end of 2023, subject to land and easement acquisition and obtaining necessary environmental and development approvals. The future incremental capital works of moving from 132 kV operation to 275 kV operation centre on substation works[79] and are expected to take two years to complete.

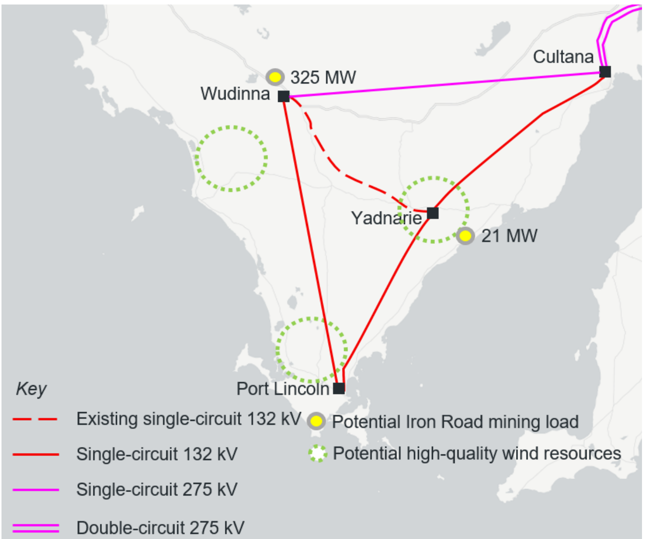
[79] At the Cultana, Wudinna, Yadnarie and Port Lincoln substations.

Figure 41 – Network configurations possible under Option 5C



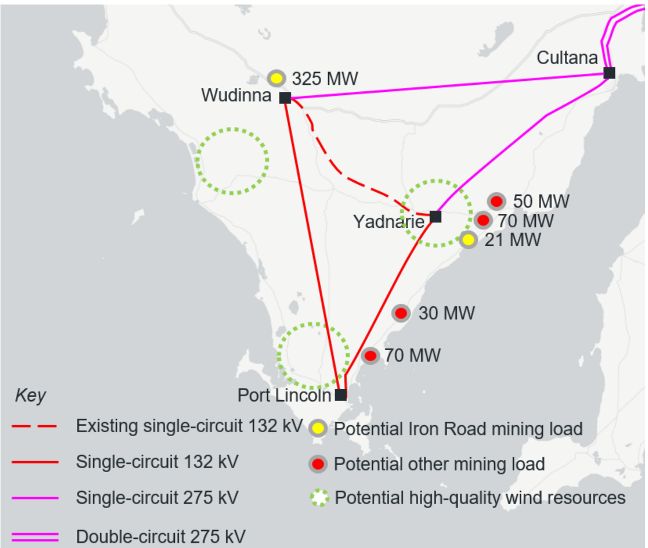
Stage 1

If no mining load commits or wind generation locates on the Eyre Peninsula then set of single-circuit sections will remain at 132 kV.



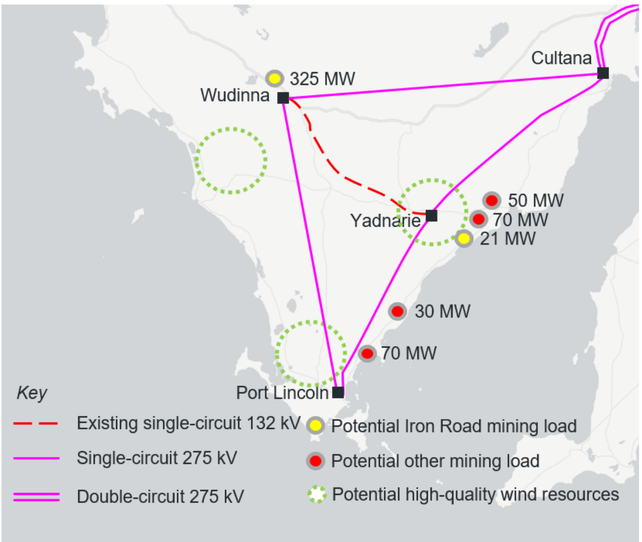
Stage 2

If Iron Road's CEIP reaches committed status, then ElectraNet will upgrade the Cultana to Wudinna section to 275 kV.



Stage 3

If the CEIP project reaches committed status as do the other assumed mining loads, then ElectraNet will upgrade both the Cultana to Wudinna and Cultana sections to 275 kV.



Stage 4

If the Eyre Peninsula is designated as a priority for renewable energy development, then ElectraNet will upgrade the entire set of single-circuit lines to 275 kV.

Appendix E Summary of PSCR submissions

This appendix presents a summary of, and commentary on, the PSCR submissions received, in accordance with the NER (clauses 5.16.4(v) and 5.16.4(k)). It essentially re-presents Section 3 of the PADR but also updates the responses to be consistent with the PACR assessment and the key developments since the PADR was released.

We received 15 submissions to the PSCR, representing a range of views and interests – namely:

- local Eyre Peninsula representatives and individuals;[80]
- parties offering network support at Port Lincoln;[81]
- customer representatives;[82] and
- wind farm developers and mining companies.[83]

E1 Interaction with the ESCOSA reliability review for the Eyre Peninsula

On 7 April 2017, ESCOSA initiated the "Inquiry into reliability and quality of electricity supply on the Eyre Peninsula" following concerns raised by Eyre Peninsula community members about the customer impacts arising from the level of reliability and quality of supply in the region.

A number of parties raised the distribution-level options identified in the ESCOSA reports as reflecting relatively low-cost solutions to improving reliability outcomes for customers in the region.[84] We consider that the distribution-level options may in fact offer cost effective ways to reduced expected unserved energy to customers on the Eyre Peninsula. However, these initiatives would likely need to be subject to a separate Regulatory Investment Test for Distribution.

The Consumer Challenge Sub-Panel No. 9 (CCP9) stated its support for ESCOSA's finding that reliability issues on the Eyre Peninsula would benefit from more joint planning between ElectraNet and SA Power Networks. It recommended ElectraNet respond to the draft findings of the ESCOSA inquiry by creating opportunities for more joint planning and through resetting the timeline for the Eyre Peninsula RIT-T.

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80 District Council of the Lower Eyre Peninsula, Energy Security for SA Working Party, Regional Development Australia Whyalla and Eyre Peninsula and the Eyre Peninsula Local Government Association, Mr Fred Gerschwitz and Mr Geoff Rayson.

81 AES Energy Storage, Aggreko/Marubeni Power Developments JV, Engie and Karpower International.

82 Business SA, The Consumer Challenge Sub-Panel No. 9 and Mr Tim Kelly as the Nominated Conservation Council SA volunteer, serving on the ElectraNet Consumer Advisory Panel.

83 Iron Road, Meridian Energy and The South Australian Chamber of Mines and Energy.

84 Consumer Challenge Sub-Panel No. 9, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, pp. 5-6; Business SA, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 20 July 2017, p. 1; and Engie, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, p. 5.

CCP9 also recommend that the Australian Energy Regulator (AER) should support independent oversight of a specific joint planning and investment test project that involves ElectraNet, SA Power Networks, The Australian Energy Market Operator (AEMO), ESCOSA, consumers and proponents of network support solutions.[85]

We have always worked very closely with SA Power Networks on every potential and realised development to ensure optimal solutions have always been fully investigated. We have regularly discussed the status of this RIT-T with SA Power Networks at our regular joint planning meetings. SA Power Networks also reviewed and provided feedback, which we incorporated, on the RIT-T reports prior to publication.

ESCOSA's inquiry into the reliability and quality of electricity supply on the Eyre Peninsula that was undertaken in 2017[86] had found that there could be an economic case in the medium term for back-up generation to be installed at various locations on the Eyre Peninsula. SA Power Networks has advised through joint planning that with the increased reliability that the preferred option of this RIT-T is expected to deliver to connection points on the Eyre Peninsula, there is no longer expected to be an economic case for the back-up generation to be installed.

It is important to recognise that the transmission options being explored as part of this RIT-T are expected to deliver a broader range of market benefits over and above the reliability benefits highlighted in the ESCOSA report, and may displace some of the generation options proposed by SA Power Networks.

Comparing the SA Power Networks and ElectraNet options only on the basis of improvements in reliability (minutes saved) and estimated cost may give the false impression that the SA Power Networks' options should be prioritised over the transmission options. In particular, as demonstrated in this PADR, transmission options will deliver a broader range of market benefits via enabling potential future mining loads to connect to the transmission network, as well as unlocking the potential for additional wind generation (even though this is found to be insignificant in the PACR assessment).[87,88]

In addition, the estimated cost of each of the distribution-level options excludes the reinvestment necessary to maintain reliability of supply to the Eyre Peninsula given the condition of the existing transmission assets.

We consider that this logic also applies to any consideration of a micro-grid solution for the Eyre Peninsula.[89] In particular, while a micro-grid solution may be technically feasible, it would not capture the substantial wider market benefits that primarily network options provide and, consequently, would not satisfy the RIT-T.

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85 Consumer Challenge Sub-Panel No. 9, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, pp. 3 & 9.

86 ESCOSA, *Inquiry into the reliability and quality of electricity supply on the Eyre Peninsula*, Final Report, October 2017. Available at https://www.escosa.sa.gov.au/ArticleDocuments/1086/20171027-Inquiry-ReliabilityQualityOfElectricitySupplyEyrePeninsula-Final.pdf.aspx?Embed=Y.

87 These benefits are captured in the RIT-T framework in terms of their impact in lowering dispatch and investment costs in the NEM.

88 For a detailed discussion of the interaction between the distribution-level options and the transmission options considered in this PADR/RIT-T, please refer to ElectraNet's submission to the ESCOSA draft report, available at: http://www.escosa.sa.gov.au/ArticleDocuments/1085/20170831-Inquiry-ReliabilityQualityElectricitySupplyEyrePeninsula-DraftReportSubmission-ElectraNet.pdf.aspx?Embed=Y

89 Consumer Challenge Sub-Panel No. 9, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, p. 3.

E2 Options proposed in the PSCR

The most commonly supported future network capacity supported in submissions was a 275 kV solution. A large number of submitters commented on the need for there to be a 275 kV network on the Eyre Peninsula, particular to assist with accommodating any future mining and/or wind generation. Specifically:

- the District Council of the Lower Eyre Peninsula requested that a double-circuit 275 kV line down the spine of the Eyre Peninsula be investigated in order to allow for future industry development, with acknowledgement that this line will be managed as a 132 kV line unless demand warrants instigation of the full 275 kV capacity – the council also requests that at a minimum a dual circuit 132 kV transmission line be provided to Eyre Peninsula;[90]

- Business SA notes that future significant mining loads would likely require additional transmission capability beyond 132 kV;[91]

- Tim Kelly, Nominated Conservation Council SA volunteer, serving on the ElectraNet Consumer Advisory Panel, considers that two geographically separated single-circuit 275 kV lines, initially operated at 132 kV, is the only option that meet the three aspects of regional transmission reliability, capacity for demand growth and capacity for generation growth of wind power;[92]

- the South Australian Chamber of Mines and Energy (SACOME) considers there is a need for a reinforcement of the transmission line from 132 kV to a double-circuit 275 kV to support mining and other developments in the region;[93]

- Iron Road submitted that a 275 kV line is a vital component for the CEIP to go ahead;[94]

- Regional Development Australia Whyalla and Eyre Peninsula (RDAWEP) and the Eyre Peninsula Local Government Association (EPLGA) consider that two geographically separated single-circuit 275 kV lines, initially operated at 132 kV, is the preferred option and that, at a minimum, two geographically separated single-circuit 132 kV lines should be constructed.[95]

Consistent with these submissions, the assessment of options in both the PADR and PACR includes options that are built at 275 kV initially, as well as options that have the capability to be operated at 275 kV but are operated at 132 kV initially.

Several parties also suggested that the assessment should consider running transmission lines from Cultana to Port Lincoln via Wudinna.[96] The attraction of such a network configuration is its ability to provide heightened supply reliability to the Eyre Peninsula and lessen the likelihood of future interruptions to supply.

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90 District Council of the Lower Eyre Peninsula, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, p.1.

91 Business SA, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 20 July 2017, p. 3.

92 Tim Kelly, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 27 July 2017, pp. 2-4.

93 SACOME, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 24 July 2017, p. 1.

94 Iron Road, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 18 July 2017, p. 1.

95 RDAWEP & EPLGA, *Submission in relation to Eyre Peninsula RIT-T PSCR* [via email].

96 RDAWEP & EPLGA, *Submission in relation to Eyre Peninsula RIT-T PSCR* [via email]; and Submission of Fred Gerschwitz to the Eyre Peninsula RIT-T PSCR

As a result, we have investigated a number of credible options that involve two geographically diverse single-circuit lines from Cultana to Port Lincoln where one goes via Yadnarie and the other goes via Wudinna (Options 5A, 5B and 5C).

CCP9 noted the importance of the option value of deferral/staging strategies and commends ElectraNet's commitment to the consideration of the option value of alternative investments as it can reduce the risk of customers having to pay for assets that would otherwise be stranded.[97]

Meridian Energy submitted that simply reconductoring the existing 132 kV line and continuing with network support at Port Lincoln was undesirable. Meridian submitted that doing so may restrict further growth in the area, of both generation and load, and would provide a less robust and secure network solution. Meridian Energy consider that the nature of the support provided in Option 1, while it may technically meet reliability standards, is not truly comparable with the other options provided.[98]

The Energy Security for SA Working Party submitted that any option that relies on the continued operation of the existing power station at Port Lincoln raises concerns as to the reliability and adequacy of ongoing maintenance and support of the existing generation equipment.[99] It states that the current Port Lincoln Power Station, which is currently identified as the backup power supply in case of blackout, has not successfully operated for some time and costs $10 million annually.[100]

Engie, which hold the current network support contract at Port Lincoln, was the only party to explicitly express support for the reconductoring option and seeking a new network support agreement to maintain the required reliability level at Port Lincoln. Engie state that it would be unfortunate if a decision was taken to build a costly double-circuit transmission line south to Port Lincoln, only to then find that a substantial new load project seeks network connection in the northern or western part of the Eyre Peninsula.[101]

We appreciate this position but note that, equally, it would also be unfortunate if the network was underbuilt and new mining located on the peninsula for a higher connection cost, or wind generation on the Eyre Peninsula was constrained by the network capacity. The RIT-T, and wider network planning process, is designed to recognise, and thoroughly test, for the *expected* case considering the various uncertainties that exist – reflecting this, we have assessed all credible options across a range of underlying future 'states of the world' and general modelling assumptions.

The Energy Security for SA Working Party recommend that a 500 kV network be included and assessed as part of the RIT-T, stating that 132 kV and 275 kV options are not sufficient to allow the development of the full potential of resources on the Eyre Peninsula.[102] We do not consider at this stage that the significant cost of 500 kV network options would be justified in terms of the *additional* market benefits they can be expected to deliver over and above the 275 kV options included in this report.

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97 Consumer Challenge Sub-Panel No. 9, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, pp. 3-4 & 8.

98 Meridian Energy, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 20 June 2017, p. 1.

99 Energy Security for SA Working Party, *Submission in relation to Eyre Peninsula RIT-T PSCR*, pp. 3-5.

100 Energy Security for SA Working Party, *Submission in relation to Eyre Peninsula RIT-T PSCR*, p. 2.

101 Engie, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, pp. 4-5.

102 Energy Security for SA Working Party, *Submission in relation to Eyre Peninsula RIT-T PSCR*, pp. 3-5.

In particular, the cost of building a 500 kV transmission network on the peninsula has been estimated to be in the order of $2 billion in this PACR assessment and it is not expected that it would deliver commensurate levels of market benefit.

E3 Network support at Port Lincoln

We received submissions to the PSCR from several parties offering network support at Port Lincoln, representing a variety of generation and technology solutions.

While the details of these submissions have been requested to be kept confidential, we have subsequently liaised with these parties regarding their proposed network support solutions and, on 28 September 2017, released a formal RFT to request financial and operating parameters from network support proponents.

The ongoing communication with network support proponents and responses to the formal RFT have greatly assisted us in developing updated assumptions regarding future network support costs at Port Lincoln for Option 1 in both the PADR and PACR. Further detail on the process for reviewing and assessing the various network support proposals received can be found in section 8.1 of the PADR and section 8.2 of this PACR. We are grateful for the network support proposals received.

E4 Extent of mining potential on the Eyre Peninsula

Several submissions noted the mining load potential on the Eyre Peninsula.[103]

Iron Road stated that after the PSCR was released, on 3 May 2017, the Government of South Australian granted the CEIP Mining Lease and Development Approval.

It further noted that the rail and port component has previously been declared a 'priority project' by Infrastructure Australia, one of only 10 projects nationwide, and the CEIP enjoys 'major project facilitation' by the Australian Government, the only South Australian project to receive this status.

Iron Road stated that it expects to make a final investment decision by the end of 2017 on the CEIP, with financial close expected during 2018, and noted that three major banks have formally expressed interest in providing debt finance for the project and discussions with these entities are advanced.[104]

SACOME stated that there are several mineral projects currently active on the Eyre Peninsula and three are at a mature stage of development (including the CEIP, which is targeting a 2018-2019 date for construction and first ore by 2021-2022).[105]

The assessment in this RIT-T takes into account the potential for future mining development on the Eyre Peninsula, as well as the uncertainty in relation to that development.

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[103] Consumer Challenge Sub-Panel No. 9, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, p. 3; Iron Road, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 18 July 2017, p. 1; Engie, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, p. 3; SACOME, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 24 July 2017, p. 1; Submission of Geoff Rayson to the Eyre Peninsula RIT-T PSCR, 20 June 2017.

[104] Iron Road, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 18 July 2017, p. 1.

[105] SACOME, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 24 July 2017, p. 1.

In particular, the analysis considers three future states of the world in which either no mining investment occurs, the CEIP project goes ahead, or the CEIP project and a range of other mining projects go ahead. We have also refined a number of modelling assumptions to capture the benefit from connecting new mines more accurately (these are outlined in sections 5, 6 and 7 of this PACR).

If CEIP (or another project) commits to developing a mine before construction of the preferred option (Option 4D), then at that stage the uncertainty in relation to mining development would disappear.

E5 Extent of wind generation potential on the Eyre Peninsula

Submissions also commented on the wind generation potential on the Eyre Peninsula.[106]

Meridian Energy stated that, while the Eyre Peninsula is widely renowned as having the best wind resources in Australia, the failure of the current network to be able to support further generation investment at a time of major development in renewable energy imposes significant market costs that are borne by all customers. Meridian Energy stated that, while it is difficult to forecast the likelihood of additional generation or load connecting, they believe that additional investment in the network, and relief of existing constraints, will lead to additional connections of both generation and load.[107]

The Energy Security for SA Working Party reiterated the significant electricity generation capacity on the Eyre Peninsula. In particular, they quoted the 2010 Select Committee on Wind Turbines Report undertaken by Worley Parsons and Macquarie Capital ('the Green Grid' study), which identified over 4,000 MW of easily harvested wind generation.

The Energy Security for SA Working Party also suggested that a further capacity of over 4,000 MW of solar generation available on Eyre Peninsula has been identified.[108]

Tim Kelly, Nominated Conservation Council SA volunteer, serving on the ElectraNet Consumer Advisory Panel, suggested that the modelling provide for identified and plausible wind farm sites and any major solar PV array or solar thermal sites on Eyre Peninsula. He also raised the interaction between this RIT-T and the significant work previously undertaken under the Green Grid study.[109]

We consider that, at the time of the PSCR and PADR, the earlier 2010 Green Grid work to be the most thorough public consideration to-date of the renewable energy potential on the Eyre Peninsula. The PADR consequently drew on it to develop a range of assumptions regarding the quantity and quality of new wind generation on the Eyre Peninsula.

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106 Consumer Challenge Sub-Panel No. 9, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, p. 3; Business SA, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 20 July 2017, p. 1; Meridian Energy, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 20 June 2017, p. 1; Engie, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, p. 3; Energy Security for SA Working Party, *Submission in relation to Eyre Peninsula RIT-T PSCR*, p. 2; Submission of Geoff Rayson to the Eyre Peninsula RIT-T PSCR, 20 June 2017.

107 As an example, Meridian Energy stated that, while it is currently exploring development of new large scale solar plants, they have excluded the Eyre Peninsula from such explorations due to the existing network constraints (despite it having a number of advantages for them, including an existing connection arrangement at Mt Millar. See: Meridian Energy, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 20 June 2017, pp. 1-2.

108 Energy Security for SA Working Party, *Submission in relation to Eyre Peninsula RIT-T PSCR*, p. 2.

109 Tim Kelly, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 27 July 2017, pp. 2-4.

The PACR assessment updates these assumptions based on significant work undertaken by AEMO as part of the recent ISP. These assumptions and their impacts are defining features of the PACR assessment and are discussed at-length throughout the body of this PACR.

While Engie also noted that the Eyre Peninsula has long been recognised as an area that has significant mineral resources and exploration potential, as well as very good wind and solar potential, they consider the sparsely populated nature of the region means it is difficult to justify building significant transmission infrastructure. Engie consider that ElectraNet cannot simply build a new transmission line in anticipation of new generation or load projects emerging to take advantage of the network. Engie further note the uncertainty regarding new mining and/or renewable projects on the Eyre Peninsula and whether they will proceed.[110]

We appreciate that both mining developments and renewable generation potential on the Eyre Peninsula are uncertain. Reflecting this uncertainty, we have applied a combination of both wholesale market modelling and real option value techniques to capture and test uncertainties in the analysis.

We consider that this treatment of future uncertainty, and assessment of the prudent and efficient investment decision to make today, is consistent with the RIT-T framework. Importantly, the wholesale market modelling undertaken for this RIT-T does not assume that wind generation will automatically locate on the Eyre Peninsula if the network is upgraded to 275 kV, but only if this represents the least cost generation solution given assumed demand conditions and the associated firming costs.

A number of parties raised the interaction between this RIT-T and the recommendation from the independent Finkel Review regarding the Australian Energy Market Operator (AEMO), in conjunction with transmission network providers, developing an integrated plan to facilitate the efficient development and connection of renewable energy zone across the NEM. [111] In particular, parties were concerned that a RIT-T committing to build transmission infrastructure on the Eyre Peninsula ahead of such planning may be premature, and may also result in additional costs being picked up by South Australian customers.

The RIT-T assessment in the PADR captured this impact through inclusion of an 'environmental policy trigger' to upgrade operation of the network to 275 kV and has also allowed for the uncertainty about whether this trigger will occur. Given that the condition of the existing network requires ElectraNet to make an investment decision now, it would not be prudent to wait for the out-workings of the AEMO process to identify renewable zones, which is not expected until mid-2018, at the earliest. The reduced impact on the wholesale market, from aligning wind quality assumptions with the ISP, have meant that this is no longer a key investment driver for the Eyre Peninsula.

[110] Engie, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, pp. 3-4.

[111] Business SA, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 20 July 2017, p. 3; Energy Security for SA Working Party, *Submission in relation to Eyre Peninsula RIT-T PSCR*, p. 2; and Consumer Challenge Sub-Panel No. 9, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, p. 6.

Business SA notes that ElectraNet's decision to build a new interconnector to either New South Wales or Victoria will be a key contributing factor in any case to build up the transmission capability of the Eyre Peninsula to export renewable energy.[112]

We note the important interaction between the ability to develop wind generation on the Eyre Peninsula and the extent of interconnection with the rest of the NEM. We have consequently included a sensitivity test, investigating how the various costs and market benefits of each credible option are affected through the presence of a new interconnector.

E6 Interaction with the coincident regulatory determination for ElectraNet

Our revenue proposal for the 2018-2023 period includes two capex projects to refurbish the existing 132 kV transmission lines supplying the Eyre Peninsula a cost of approximately $80 million (which has been included as Option 1 in this RIT-T).[113] The proposal also includes a contingent project to evaluate the options of a full line replacement, and potentially circuit duplication that would avoid expensive network support arrangements at Port Lincoln. This RIT-T is a key trigger event for this contingent project.[114]

In April 2018, the Australian Energy Regulator (AER) accepted our revenue proposal that included capital expenditure of about $80 million for these replacement works, and ongoing network support to provide backup supply to Port Lincoln, as well as a contingent project cater for this RIT-T.[115]

We consider this to be the prudent and efficient way to proceed since:

- it has separately investigated and consulted on the most cost-effective ways to improve supply reliability to the Eyre Peninsula (i.e., via this RIT-T); but
- sections of the exiting line built in 1967 are nearing the end of their functional life (a standard line life of 55 years) and require replacement in the next few years.

CCP9 notes that the AEMC *Final rule on new planning arrangements for replacement assets by electricity network businesses* has been released and that the Eyre Peninsula reconductoring projects in the ex-ante revenue proposal exceed the investment threshold and would be the subject of a RIT-T under the new rule. They recommend that, given a closely related RIT-T process has been initiated, the reconductoring projects should be removed from the ex-ante revenue proposal and assessed as part of the Eyre Peninsula RIT-T.[116]

However, as noted above, the AER has accepted ElectraNet's capital expenditure forecast in full, including the Eyre Peninsula line reconductoring projects.

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[112] Business SA, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 20 July 2017, p. 1.

[113] ElectraNet, *Revenue Proposal 2019-2023*, Attachment 6 – Capital Expenditure, p. 19.

[114] ElectraNet, *Revenue Proposal 2019-2023*, Attachment 6 – Capital Expenditure, p. 47.

[115] AER, *ElectraNet Transmission Determination 2018 to 2023*, Final Decision, Attachment 6 – Capital Expenditure, April 2018, pp, 11-15.

[116] Consumer Challenge Sub-Panel No. 9, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, p. 4.

This RIT-T considers the most appropriate long-term solution for the Eyre Peninsula. Since the preferred Option 4D has been confirmed to be the outcome of the RIT-T economic assessment, a contingent project for the Eyre Peninsula will now be triggered.

E7 Application of a bespoke VCR estimate

Under the RIT-T assessment, the benefit associated with the reduction in unserved energy is valued at the Value of Customer Reliability (VCR), expressed in $/kWh. In its submission, the CCP9 states concern about the bespoke VCR estimates proposed in the PSCR leading to increased capital expenditure.[117]

As outlined in the PSCR, the suggestion to apply VCR estimates that depart from the standard AEMO estimates was to appropriately capture the severe and prolonged outages contemplated in this RIT-T and experienced by customers on the Eyre Peninsula.[118]

The assessment in this RIT-T indicates that most of the market benefits associated with each of the investment options relates to their impact on the wholesale market, rather than on the level of unserved energy. We have opted to apply the standard AEMO VCR estimates to valuing reductions in unserved energy expected from each credible option, considering the concerns raised by the CCP9, and given the non-materiality of the VCR value for the outcome of this RIT-T assessment.

We have not undertaken a sensitivity on the VCR (or changes in transmission losses) since these categories of benefit are found to be immaterial in differentiating between credible options, as shown in section 8 of this PACR. Even assuming a VCR of $0/kWh does not change the result.

E8 Price impact to customers

Business SA and the CCP9 both raised the likely price effect to customers of reinforcing the Eyre Peninsula transmission network.[119] The CCP9 stated a desire for the price impacts to customers to be explained.[120]

Section 10 includes a discussion on the customer price impact of the preferred option that is shown in this final report to deliver the greatest net benefits under the RIT-T economic assessment, with the preferred option expected to have a negligible price impact on the transmission component of the annual electricity bill for an average residential customer.

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[117] Consumer Challenge Sub-Panel No. 9, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, pp. 9-10.

[118] The inappropriateness of applying AEMO's VCR estimates to assessing the cost to customers of events that cause wide-spread, severe or prolonged supply shortages is noted by AEMO in its VCR Application Guide. See: AEMO, *Value of Customer Reliability – Application Guide*, Final Report, December 2014, p. 20.

[119] Consumer Challenge Sub-Panel No. 9, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, p. 8; and Business SA, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 20 July 2017, p. 1.

[120] Consumer Challenge Sub-Panel No. 9, *Submission in relation to Eyre Peninsula RIT-T PSCR*, 21 July 2017, p. 8.

Appendix F The general assessment framework and the market benefit categories not expected to be material

This appendix reproduces material from section 8 of the PADR regarding general modelling parameters adopted, as well as the classes of market benefit that are not expected to be material. These have not changed since the PADR.

F1 Description of general modelling parameters adopted

This section outlines the assessment period selected, as well as the assumptions regarding an appropriate commercial discount rate.

F2 Assessment period

The RIT-T analysis has been undertaken over a 20-year period, from 2019 to 2038.

We consider that a 20-year period takes into account the size, complexity and expected life of the relevant credible options to provide a reasonable indication of the market benefits and costs of all credible options.

Specifically, consistent with the AER RIT-T Application Guidelines, we consider that by the end of the modelling period, the network will be in a 'similar state' in relation to needing to meet a similar identified need to where it is at the time of this investment.[121]

While the capital components of the credible options have asset lives greater than 20 years, we applied a terminal value approach to incorporating capital costs in the assessment. This ensures that the capital cost of long-lived options is appropriately captured in the 20-year assessment period.

F3 Commercial discount rates applied

The commercial discount rate is applied to calculate the NPV of costs and benefits of credible options.[122]

We have adopted a real, pre-tax discount rate of 6 per cent as the central assumption for the NPV analysis presented in this PADR.[123]

The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated real, pre-tax weighted average cost of capital (WACC) be used as the lower bound discount rate in the sensitivity testing.

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

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

[123] ElectraNet notes that it is consistent with the recent Powering Sydney's Future RIT-T, jointly undertaken by TransGrid and Ausgrid.

We have therefore tested the sensitivity of the results to changes in this discount rate assumption, and specifically to the adoption of a lower bound discount rate of 3.62 per cent,[124] and an upper bound discount rate of 8.5 per cent.

F4 Classes of market benefit not expected to be material

The NER requires that all categories of market benefit identified in relation to the RIT-T 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.[125]

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

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

[124] AER, Draft decision *ElectraNet transmission determination – Post tax revenue model*, 26 October 2017, 'WACC' spreadsheet. The real, pre-tax WACC of 3.62% corresponds to a 'headline' nominal vanilla WACC of 5.75%.

[125] 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.

Table 6 – Market benefit categories under the RIT-T not expected to be material

Market benefits	Reason for excluding from this RIT-T
Changes in ancillary services costs	The cost of frequency control ancillary services (FCAS) may increase as a consequence of any increase in the installed capacity or output of wind generation resulting from the network investment options considered. However, FCAS costs are relatively small compared to total market impacts, and so are not likely to be material in the selection of the preferred option under the RIT-T. Inclusion of all, or some, of the FCAS markets using market modelling under the RIT-T would lead to a substantial increase in the complexity and cost of the RIT-T assessment. We consider that such increased complexity is not warranted given that changes in FCAS costs will not have a role in determining the preferred option for this RIT-T assessment. There is no expected change to the costs of Network Control Ancillary Services and System Restart Ancillary Services as a result of the options being considered. Therefore, these costs are considered not material in the assessment of a preferred option in this RIT-T assessment.
Competition benefits	Competition benefits are net changes in market benefit arising from the impact of the credible option on participant bidding behaviour. However, none of the credible options considered address network constraints between competing generating centres and therefore is unlikely to offer any material competition benefits. Moreover, the calculation of competition benefits would require substantial additional market modelling. For this reason, We have not estimated any competition benefits as part of this RIT-T assessment.
Voluntary load curtailment	The level of voluntary load curtailment currently present in the NEM is limited. Where the implementation of a credible option affects pool price outcomes, and results in pool prices reaching higher levels on some occasions than in the base case, this may have an impact on the extent of voluntary load curtailment. We consider that the market benefit associated with this category of benefit is not expected to be material for this RIT-T assessment, given the limited extent to which such curtailment currently occurs in the market, and therefore the expected low magnitude of this benefit.
Non-related network investment	Under the RIT-T, differences in the timing of transmission investment must be quantified if the changed transmission investment is driven by a need unrelated to any of the works that form part of the credible option. We do not believe that the timing of any non-related transmission investments will be affected by any of the credible options being considered as part of this RIT-T. Consequently, we have not estimated any market benefits associated with the timing of any non-related network investments as part of this RIT-T assessment.

Appendix G Additional detail on the market modelling applied

This appendix provides greater detail on the least cost modelling approach applied by HoustonKemp as part of this RIT-T, as well as how it draws on the latest AEMO inputs (including how variable and fixed costs are accounted for).

G1 Overview of key assumptions and modelling approach

This section provides further detail on the market modelling applied by HoustonKemp in estimating the market benefits associated with expansion of the Eyre Peninsula. An assumptions book detailing the input assumptions is provided as Appendix M.

G2 Input assumptions

HoustonKemp has aligned inputs assumptions with those by AEMO in the modelling for the ISP. This has led to a number of changes relative to the modelling for the PADR, most notably:

- reduction in wind capacity factors on the Eyre Peninsula in absolute term and relative to other regions within South Australia;
- reduction in capital costs for new wind generation, solar PV and battery storage – battery storage costs in particular have decreased substantially;
- inclusion of the Victorian Renewable Energy Target (beyond 2020) and Queensland Renewable Energy Target in the base case modelling;
- alignment of the retirement of generators with the assumed retirement profile in the ISP based on the end of the technical lives of generators;
- revisions to demand and rooftop solar PV forecasts; and
- incorporation of build limits due to resource availability and transmission constraints aligned with REZs

G3 Emissions and renewables policy

The modelling makes the following assumptions regarding the emissions and renewable policies, which are consistent with the ISP:

- COP21 emissions reduction projection of 28 percent (base case) and 52 percent (sensitivity case);
- VRET target of 40 per cent by 2025; and
- QRET target of 50 per cent by 2030.

The COP21 emissions reduction target is modelled as a limit on the quantity of emissions that can be produced in each year. This approach does not involve making any explicit

assumptions regarding the nature of the mechanism that delivers on the policy but assumes that the mechanism operates in a technologically neutral manner.

The VRET target is modelled as a per annum MW target based on profiles developed by AEMO to meet the 40 per cent by 2025 target. The QRET is modelled as an annual GWh target based on the Neutral BAU case developed by AEMO.

G3.1 System security

A cap on non-synchronous generation until end of FY2022 has been applied. The cap has been raised by 95MW since the publication of PADR. This approach aligns with approach utilised in the SAET RIT-T.

We no longer apply a floor on synchronous generation in each period until FY2022 as per the modelling for the PADR. Rather, we apply a floor on the quantity of gas fired generation in each year in line with minimum generation levels applied in the ISP. The removal of the synchronous generation floor reflects the installation by ElectraNet of synchronous condensers to address system security in the state.

G3.2 REZ transmission limitations

The market modelling projects uptake of renewable generation sources in each of the Renewables Energy Zones defined by AEMO in the ISP. Under the ISP, AEMO incorporates constraints on the amount of renewable generation that can be connected to the transmission network in each REZ and the costs of expanding the transmission network connecting REZs to enable the connection of additional renewable energy.

HoustonKemp has incorporated the transmission-related constraints on new build in REZs in the market modelling to capture the impacts on the relative costs of investment in new renewable generation in different REZs.

G3.3 Eyre Peninsula new investment limits

We have made modest revisions to limits on new generation that can connect to the Eyre Peninsula under each of the options. However, these build limits are a lot less relevant in the PACR modelling than the PADR modelling on account of the revised assumption regarding the quality of the wind resource on the Eyre Peninsula.

In arriving at the final new build profiles for investment HoustonKemp conducts a review of the new build to ensure that the build profile is consistent with the assumed level of losses for new entrant generators.

G3.4 Load block slicing methodology

In order to reach a balance between model run time and granularity of the modelling we apply a load block slicing methodology to identify a subset of dispatch intervals to model.

Load blocks are commonly used in long-term generation and investment models of wholesale markets. For the market modelling HoustonKemp have adopted 15 representative days with 6 periods per day.

The load blocks have been developed as follows:

- For demand, wind and solar PV output traces for a representative year (2016-17 in this case), we classify each of the 17520 half hourly observations by their time of day (i.e., a number from 1 to 48).

- We then apply a clustering algorithm to identify which days are statistically the most similar based on daily profiles of demand, wind and solar output and group them into 15 groups based on this similarity. We partition off the days with the top 10 per cent of demand and allocate these into 5 groups and then allocate 10 groups for the remaining 90 per cent of days.

- To calculate the representative daily profiles, we then assume that each daily profile is to be represented by 6 blocks (which can represent a varying number of periods) by applying a sequential clustering algorithm to each of these groups of days. This results in 15 sequences of 6 blocks to represents daily profiles for demand, wind and solar.

- To ensure the sequences that represent daily profiles of wind represent the actual variability of wind output and their correlation with demand traces, we have applied a new methodology of evaluating wind profiles with reference to actual wind profiles that are scaled to have a representative capacity factor and correlation with demand.

- Finally, we identify the 5 periods of maximum demand for each region and specify these as their own individual load blocks. This results in 95 total dispatch intervals being modelled.

This approach improves upon the methodology applied in the PADR by:

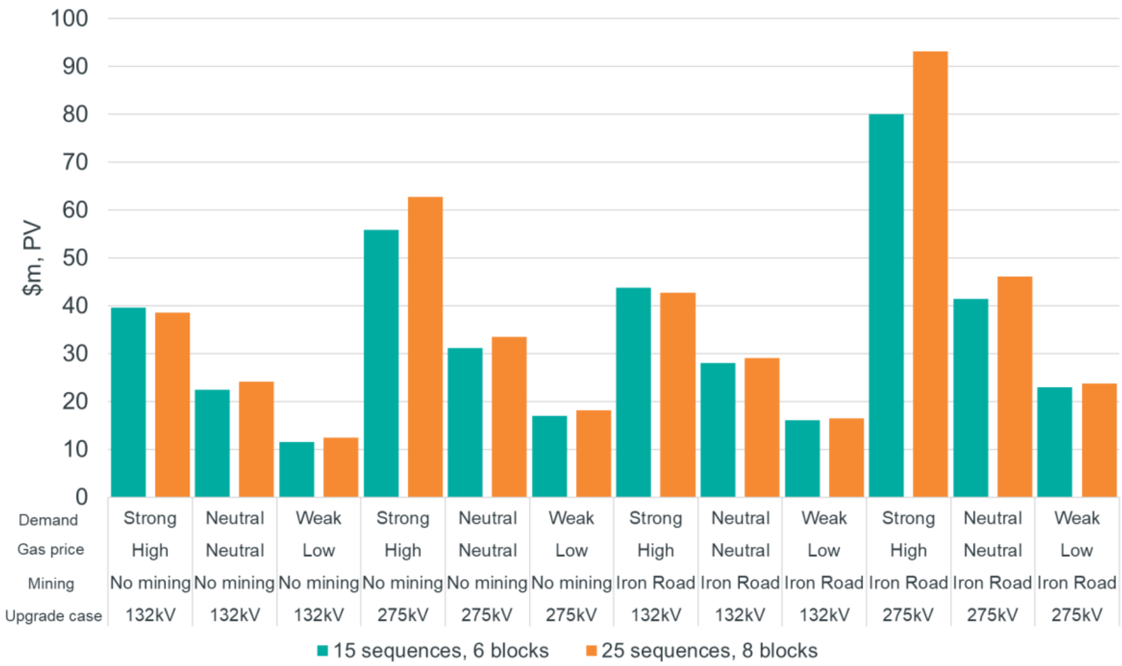
- incorporating intra-day variation in wind profiles based on actual data, rather than averages across data with adjustments to capture intra-day variation; and

- increasing the accuracy of correlations between variables through traces based on actual days.

Our analysis indicates that these changes in methodology do not have a material impact on the resulting estimates of market benefits. The chart below shows the net market benefits for a subset of various market assumptions and connection types for both the market modelling analysis using 15 sequences and 6 blocks, compared to a more granular method using 25 sequences and 8 blocks.

This analysis shows that the market benefits only differ by a small amount using the more granular approach and tend to increase the net market benefits, indicating that the approach used in this analysis is likely to return a conservative estimate of net market benefits.

Figure 42 – Summary of market benefits under different load block slicing methodologies



Appendix H Responses to specific modelling questions from Engie

Due to changes in modelling assumptions and the corresponding diminished importance of market benefits we have chosen to address comments from Engie in a proportionate manner.

The table below summarises each of Engie's points raised in their submission to the PADR and provides a response to each.

Topic	Summary of Engie comments	ElectraNet and HoustonKemp response
Modelling framework	Engie state that the modelling should incorporate competitive electricity market dynamics in the modelling and that not doing so would distort estimates of costs and benefits of the options.	Least cost modelling is standard practise in projection generation and investment requirement in wholesale electricity markets and is a requirement of the RIT-T.[126] Similar approaches have been utilised by AEMO in their latest ISP and previous National Transmission Network Development Plans. In addition, a least cost modelling approach makes no assumptions about market design which is subject to change over the modelling horizon. Additional discussion on the use of least cost modelling can be found in section 4.1 above.
Modelled uptake of wind generation	Engie raised concerns regarding the high level of wind generation projected in South Australia and Tasmania. In particular, they state that the very high levels of wind generation in Tasmania and South Australia and high levels of solar generation later in the projection suggests that the correlation of output has not been adequately dealt with in the modelling). Engie also state that new build would be lower in the presence of the VRET beyond 2020.	Reported new wind generation projections in the PADR were based on weighted average new build across a range of scenarios, which included scenarios with additional mining loads on the Eyre Peninsula. In these cases, the addition of substantial load (e.g., in some cases over 500MW) was the primary driver of new wind investment. In the revised modelling for the PACR, HoustonKemp has aligned their assumptions with those in the ISP. The inclusion of the VRET beyond 2020 has increased the quantity of investment in wind generation in Victoria. Improvements to the load block slicing methodology in the PACR have also increased the accuracy of correlations between wind, demand and solar PV traces.

[126] AER, *Regulatory Investment Test for Transmission*, June 2010, pp. 8-9.

Topic	Summary of Engie comments	ElectraNet and HoustonKemp response
Correlations between variables in load block approach	Engie raised concerns that the load block approach involves averaging across time periods that may skew results and introduce bias through inaccurate correlations between variables. Specifically, Engie expressed the following concerns: • the load blocks used are coarse and don't represent specific conditions in the system (e.g. top 10 per cent of demand days are represented by 5 days intended a wide range of operating conditions) – this makes this approach difficult to benchmark against real world outcomes/events; • the averaging of system conditions to construct a load block filters out volatility and arbitrary adjustments to modelling parameters to re-introduce volatility introduce yet new and unquantifiable uncertainties; and • the correlation between demand, wind generation, solar generation and location specific relationship is all but lost in the averaging process (i.e. average correlation will be vastly different to a time series based correlation.	Modelling long term wholesale market outcomes and investment using load blocks is a very common approach and is applied by AEMO in their long-term capacity forecasting. The load block approach improves the tractability of the modelling and is an appropriate approach for this RIT-T. Appendix G outlines the refine load block slicing methodology further.
Treatment of significant non-scheduled generation	ACIL Allen estimate that significant non-scheduled grid based generators (separate from the small non-scheduled generators that AEMO nets off demand to get operation demand) generate approximately 3,700 MWh per annum, which needs to be subtracted from operation demand to determine the demand to be met by scheduled generation.	The market modelling involves projecting the least cost means of meeting 'operational demand'. Operational demand is defined as including significant non-scheduled generation, which most importantly includes non-scheduled wind farms in South Australia (e.g., Mount Millar and Cathedral Rocks). Therefore, we are not required to subtract this quantity from operational demand for input into our modelling.

Topic	Summary of Engie comments	ElectraNet and HoustonKemp response
Demand projections	ENGIE concluded that HoustonKemp has overestimated the demand to be dispatched, which may have happened in the process of translating NEM operational demand to scheduled demand. In ENGIE and ACIL Allen's view, the apparent errors in demand would lead to the conclusion that the analysis cannot be relied upon for determining market benefits, especially as they have a dependence on dispatch savings and capital investment savings. ENGIE and ACIL Allen take the view that not only should the option that is chosen be the best ranked option but it must also have positive net benefits. They claim that the errors in demand raise questions with respect to the current ranking of options, and whether options that are currently assessed as having positive benefits would continue to have positive benefits using the corrected demand inputs.	Engie is correct that the demand forecasts were modestly overestimated for the reasons described, i.e., due to a transposition error in the treatment of auxiliary loads. HoustonKemp has re-run the PADR analysis and found that this change did not materially alter the outcomes of the modelling for the PADR (including the ranking of options as a sign of net benefit). This is consistent with the demand sensitivity analysis that was undertaken in the PADR, which suggested that there was a non-linear relationship between demand and estimated market benefits. In fact, the demand sensitivities investigated a range of possible demand futures that were far broader than simply correcting for auxiliaries. The revised market modelling has addressed this transposition error in demand projections.
Technology costs	Engie observed that the 2016 NTNDP assumptions published in December 2016 were based on the 2015 Australian Power Generation and Technology Report that was published in August 2016 and claim that the data is only valid to November 2015. Engie stated that the capital costs for key plant including renewable plant are much higher than estimates that are more recent and delivered projects and that ACIL Allen in their assumptions has lower costs for solar PV, wind, CCGT and OCGT. Engie's particular concerns with regards to capital costs are: • that these differences in capital costs are likely to be material in the analysis as deferred capital or reduced investment in capacity will have less benefit; • the impact on the modelling is that there is a cost bias from solar PV towards wind, which causes wind capacity to be overstated; and • the magnitude of savings in moving from PV to wind and from lower capacity factor wind to higher capacity wind is thus overstated.	The market modelling undertaken assumptions for the PACR have been revised to align with the latest assumptions used by AEMO in their modelling for the ISP. These projections have lower costs for wind, solar PV and battery storage relative to those assumptions used in the PADR.

Topic	Summary of Engie comments	ElectraNet and HoustonKemp response
Emissions target	Engie expressed concern that the emissions targets appear incorrect for both the 28 per cent and 45 per cent targets and that the emissions target should be set as a budget for 2021 to 2030.	We have aligned the emissions target projections with the assumptions applied in the ISP.
Victorian Renewable Energy Target	Engie stated that the VRET beyond 2020 should be incorporated into the modelling.	In the PADR, the market modelling only included those renewable energy targets that had legislated mechanisms in place to deliver them. In the revised modelling for the PACR, the VRET beyond 2020 has been included to align with the approach adopted by AEMO in their modelling for the ISP. This update has contributed to the reduction in market benefits under the revised modelling for the PACR.
Locational constraints on quantity of new generation capacity	Engie expressed concerns that the annual build limits were too low and that these may be influencing the estimated build profile and line upgrade benefits. Engie also expressed concerns that the total build limits, particularly for wind generation in other regions, appear to be too low and so could be affecting the results. For example, Victoria appears limited to a total of 3,000 MW and Queensland to 1,500 MW while NSW/ACT is 5,000 MW.	The build limit utilised in the modelling for the PADR were based on build limit information sourced from the AEMO NTNDP. We have since revised the annual build limits to align with those applied by AEMO in their modelling for the ISP. These assumptions include higher annual build limits and allow for additional new build in Victoria, Queensland and New South Wales relative to previous build limit assumptions. In addition, the modelling now incorporates options to expand network infrastructure to facilitate new build.
South Australian Energy Security Target	Engie stated that it was not clear whether the energy security target was included in the modelling in the PADR. They stated that it should not be included in the modelling or at least should only be included as a sensitivity.	The South Australian Energy Security Target is no longer included in the market modelling, due to this no longer being South Australian government policy.

Topic	Summary of Engie comments	ElectraNet and HoustonKemp response
Modelling of different emissions policy mechanism	Engie expressed concerns that the approach of applying a constraint on emissions modelling did not capture the potential to differentiate policy outcomes. Engie state that different policies have different levels of economic and abatement efficiency and that some policies have other aspects that are not modelled, such as the NEG with its reliability obligation. Engie stated that is questionable whether South Australia would meet a likely reliability obligation under the projections provided by HoustonKemp. They recommend additional scenarios covering the NEG, Snowy Hydro 2.0 and the effect of a VRET/QRET (or both) should be included in the study, stating that the 28 per cent and 45 per cent scenarios are not good approximations as they assume efficient greenhouse gas abatement, whereas the above scenarios will favour technologies and locations.	We recognise that different policy designs with regards to emissions policy may result in different incentives facing renewable generation and therefore modestly different build profiles. We have included analysis of a higher emissions target and have included the QRET and VRET in the analysis to align with the ISP modelling. The wider impact of a new SA-NSW interconnector has also been captured in the assessment. However, owing the reduced significance of market benefits in the revised modelling, we do not believe it is proportionate to fully consider additional potential future policies.
Constraints on existing Eyre Peninsula wind farms	Engie stated that analysis of historical binding constraints on wind farm generation in the Eyre Peninsula area shows that constraints rarely bind and that this suggest that the removal of network constraints will not deliver meaningful benefits from increased capacity factors of existing wind generators.	The constraints on Cathedral Rocks and Mount Millar are managed by ElectraNet and therefore these constraints are not visible through AEMO constraints information. Therefore, Engie's claim that removal network constraints would not result in meaningful benefits is not correct. Further work undertaken has further refined the estimated impact of this constraint and this has been incorporated into the revised modelling.
Intra-regional constraints	Engie stated that it was no clear how intra-regional constraints have been implemented in the modelling and that accurately representing the network and dispatch conditions was important to accurately estimating benefits.	The abstraction away from detailed constraint modelling is a proportionate approach to modelling for this assessment, particularly given the focus of the analysis on 'option value' and the diminished role of market benefits under the revised modelling. The primary constraints on South Australian wind output, i.e., the cap on non-synchronous generation and floor on synchronous generation in South Australia were captured in the PADR modelling.

Topic	Summary of Engie comments	ElectraNet and HoustonKemp response
Dispatch outcomes	Engie made several observations regarding the dispatch outcomes in the modelling and comparisons to historical outcomes and modelled outcomes from ACIL Allen. These observations include: 1. overall dispatch South Australia is higher than historical dispatch outcomes; 2. wind dispatch in South Australia is higher than expected – 3. gas dispatch in South Australia is higher than expected, particularly in FY 2018; 4. Black coal appears higher than historical outcomes and 5. Brown coal aligns with estimates from ACIL Allen 6. Low gas dispatch in other regions in the NEM 7. Hydro dispatch is high relative to historical outcomes	The dispatch outcomes presented by HoustonKemp were based on a weighted average of dispatch across a range of demand, gas prices and mining load assumptions. Therefore, direct comparison of the presented dispatch outcomes to expected dispatch outcomes is not a meaningful comparison. With regards to wind dispatch outcomes in South Australia, AEMO project dispatch from wind generation in 2017-18 of 5,898GWh[127] which is substantially higher than the dispatch cited by Engie, i.e., 3,462GWh in 2017 and a projected output for 2017-18 of 4500GWh from ACIL Allen. HoustonKemp revised market modelling projects a dispatch from wind in 2017-18 of 5,941GWh. HoustonKemp has undertaken further work to review dispatch outcomes and make adjustment to the load block slicing methodology to more accurately capture variation in wind generation and other dispatch outcomes. The revised dispatch outcomes more closely align with historical data and those figures provided by Engie. The primary driver of benefits in the PADR was substitution between higher and lower quality wind resources in South Australia and the type of generation that this increased energy displaced. In many cases the displaced fuel type is not sensitive to modest changes in dispatch profiles in other regions. We note that the discrepancies pointed to by Engie are likely to impact market benefits both positively and negatively and so it is not clear that these would materially lead to an overestimate of benefits.
Renewable Energy Target	Engie state that the renewable energy projects needed to deliver the 2020 RET are incentivised to build as early as possible to maximise their creation of renewable energy certificates. Therefore, they consider it unlikely that project proponents would delay construction of committed projects and await the construction of additional transmission on the Eyre Peninsula.	Changes in input assumptions since the publication of the PADR have decreased the extent of new build on the Eyre Peninsula and which may be considered more aligned with the existing pipeline of wind projects. Notably, the revised modelling includes a revised set of committed projects across the NEM to reflect the latest advice from AEMO[128]. This has resulted in additional committed wind farms in South Australia and Victoria being committed in the modelling.

[127] AEMO, 2017 South Australian Generation Forecast, page 8
[128] AEMO, Generator Information, March 2018

Topic	Summary of Engie comments	ElectraNet and HoustonKemp response
Port Lincoln on-site generation	Engie state that the on-site generation at Port Lincoln provides a network support service also provides capability to meet the local load, including the provision of reserve generation in case of system black, or outages other than the transmission line to Port Lincoln. They also state that the Port Lincoln generators provide support the wider SA system reliability. Engie state that in the options modelling it has been assumed that these additional benefits remain in place under all options considered. However, without a network support contract, or some form of capacity support/ reliability payment, this generation may not remain in place as a merchant generator. Therefore, Engie consider that it would be appropriate to model cases where: • Port Lincoln generation is removed from service • Port Lincoln generation remains in service	ElectraNet is required to meet the ETC which stipulates that a double-circuit line to Port Lincoln is equivalent in reliability terms as the current arrangements. On occasion, we may engage in emergency generation support to provide a level of reliability higher than that required under the ETC. Separate to the identified need for this RIT-T, we are putting in-place connection facilities at Port Lincoln to provide for the connection of emergency response support.

Appendix I Other assumptions that have changed since the PADR

This section summarises a number of other assumptions that have changed since the PADR.

I1 Capital costs of the options

Table 7 – Summary of the credible option variants assessed

Option	Estimated capital cost(s) in PADR ($ million)	Estimated capital cost(s) in PACR ($ million)		
		Lines component	Substation component	Total
1 ('base case)	80 (reconductor initial sections)	80 (reconductor initial sections)	-	80
		90 (reconductor the remaining sections in 2033)	-	90
		-	25 (replace Yadnarie substation in 2037)	25
2	220	205	20	225
		-	20 (replace Yadnarie substation in 2037)	20
2B	NA	175 (build 132 kV line) + 20 (reconductor initial sections)	20	215
		25 (reconductor the remaining sections)	-	25
		-	20 (replace Yadnarie substation in 2037)	20
4A	390	230	100	330
4B	300	220	55	275
4C	310	230	20	250
	Plus 50 if the Cultana to Yadnarie line is upgraded to 275 kV	-	Plus 40 if the Cultana to Yadnarie line is upgraded to 275 kV	40
	Or, plus 90 if lines are upgraded to 275 kV	-	Or, plus 80 if lines are upgraded to 275 kV	80
		-	20 (replace Yadnarie substation in 2037 – cost only needed if Yadnarie has not been previously upgraded to a 275/132 kV substation)	20

Option	Estimated capital cost(s) in PADR ($ million)	Estimated capital cost(s) in PACR ($ million)		
		Lines component	Substation component	Total
4D	270 Plus 50 if the Cultana to Yadnarie line is upgraded to 275 kV	220	20	240
		-	Plus 40 if the Cultana to Yadnarie line is upgraded to 275 kV	40
		-	20 (replace Yadnarie substation in 2037 – cost only needed if Yadnarie has not been previously upgraded to a 275/132 kV substation)	20
3	390	395	15	410
		-	25 (replace Yadnarie substation in 2037)	25
3B	NA	255 (build 132 kV line) + 20 (reconductor initial sections)	15	290
		25 (reconductor the remaining sections)	-	-
		-	25 (replace Yadnarie substation in 2037)	25
5A	610	440	120	560
5B	450	415	35	450
		-	25 (replace Yadnarie substation in 2037)	25
5C	500 Plus 30 if the Cultana to Wudinna line is upgraded to 275 kV Or, plus 60 if the Cultana to Wudinna line AND the Cultana to Yadnarie lines are upgraded to 275 kV Or, plus 110 if all lines are upgraded to 275 kV	440	15	455
		-	Plus 25 if the Cultana to Wudinna line is upgraded to 275 kV	25
		-	Or, plus 65 if the Cultana to Wudinna line AND the Cultana to Yadnarie lines are upgraded to 275 kV	65
		-	Or, plus 110 if all lines are upgraded to 275 kV	110
		-	25 (replace Yadnarie substation in 2037 – cost only needed if Yadnarie has not been previously upgraded to a 275/132 kV substation)	25

I2 Connection costs for mines

Table 8 – Summary of the mining connection costs

Option	Mining scenario	Estimated mining connection cost(s) in PADR	Estimated mining connection cost(s) in PACR
1 (included as the 'base case)	Iron Road Other mines Iron Road and other mines	$260 million NA $650 million	$205 million $385 million $505 million
2	Iron Road Other mines Iron Road and other mines	$260 million NA $650 million	$205 million $195 million $375 million
2B	Iron Road Other mines Iron Road and other mines	NA NA NA	$205 million $300 million $480 million
4A	Iron Road Other mines Iron Road and other mines	$170 million NA $560 million	$145 million $140 million $260 million
4B	Iron Road Other mines Iron Road and other mines	$170 million NA $560 million	$145 million $105 million $230 million
4C	Iron Road Other mines Iron Road and other mines	$170 million NA $560 million	$200 million[129] $165 million[129] $285 million[129]
4D	Iron Road Other mines Iron Road and other mines	$170 million NA $560 million	$200 million[129] $165 million[129] $285 million[129]
3	Iron Road Other mines Iron Road and other mines	$260 million NA $650 million	$205 million $300 million $480 million
3B	Iron Road Other mines Iron Road and other mines	NA NA NA	$205 million $385 million $505 million
5A	Iron Road Other mines Iron Road and other mines	$90 million NA $210 million	$85 million $140 million $200 million
5B	Iron Road Other mines Iron Road and other mines	$90 million NA $470 million	$85 million $220 million $285 million
5C	Iron Road Other mines Iron Road and other mines	$90 million NA $210 million	$115 million[130] $250 million[131] $310 million[131]

[129] Includes cost to upgrade operation of the Cultana to Yadnarie lines from 132 kV to 275 kV
[130] Includes cost to upgrade operation of Cultana to Wudinna line from 132 kV to 275 kV
[131] Includes cost to upgrade operation of all new lines from 132 kV to 275 kV

I3 Marginal loss factors

Table 9 – Summary of key loss factor assumptions

Configuration	Mining Scenario	Generation Type	MLF in 2019	MLF in 2038
No upgrade	No mining	New	0.896	0.800
132kV	No mining	New	0.919	0.890
275kV-1	No mining	New	0.919	0.890
275kV-4	No mining	New	0.960	0.950
No upgrade	Iron Road	New	0.906	0.810
132kV	Iron Road	New	0.929	0.900
275kV-1	Iron Road	New	0.939	0.910
275kV-4	Iron Road	New	0.979	0.960
No upgrade	Other mines	New	0.980	0.970
132kV	Other mines	New	0.949	0.930
275kV-1	Other mines	New	0.939	0.920
275kV-4	Other mines	New	0.980	0.970
No upgrade	Iron Road + Other mines	New	0.990	0.980
132kV	Iron Road + Other mines	New	0.959	0.940
275kV-1	Iron Road + Other mines	New	0.949	0.930
275kV-4	Iron Road + Other mines	New	0.990	0.980
No upgrade	No mining	Existing	0.896	0.800
132kV	No mining	Existing	0.919	0.890
275kV-1	No mining	Existing	0.919	0.890
275kV-4	No mining	Existing	0.960	0.950
No upgrade	Iron Road	Existing	0.906	0.810
132kV	Iron Road	Existing	0.929	0.900
275kV-1	Iron Road	Existing	0.939	0.910
275kV-4	Iron Road	Existing	0.979	0.960
No upgrade	Other mines	Existing	0.896	0.800
132kV	Other mines	Existing	0.949	0.930
275kV-1	Other mines	Existing	0.939	0.920
275kV-4	Other mines	Existing	0.980	0.970
No upgrade	Iron Road + Other mines	Existing	0.896	0.800
132kV	Iron Road + Other mines	Existing	0.959	0.940
275kV-1	Iron Road + Other mines	Existing	0.949	0.930
275kV-4	Iron Road + Other mines	Existing	0.990	0.980

Appendix J NPV results

Please refer to separate Excel appendix summarising the costs and market benefits estimated.

Appendix K Summary of wholesale market benefits

Please refer to separate Excel appendix summarising the wholesale market benefits estimated.

Appendix L AME report on Eyre Peninsula mining loads

Please refer to separate report from AME assessing the potential for mining loads on the Eyre Peninsula.

Appendix M Market modelling assumptions book

Please refer to separate Excel appendix detailing the assumptions used in the wholesale market modelling.