RIT-T ASSESSMENT: EYRE PENINSULA SUPPLY OPTIONS

A FINAL REPORT PREPARED FOR THE AER

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CONTENTS

Figures

1 INTRODUCTION

Frontier Economics (Frontier) has been engaged by the Australian Energy Regulator (AER) to independently assess the forecast gross market benefits of an upgrade to the single-circuit 132kV line serving the Eyre Peninsula proposed by ElectraNet.

This report presents our assessment of the analysis undertaken by ElectraNet and its consultants as presented in the Eyre Peninsula Electricity Supply Options Project Assessment Conclusions Report (PACR).

1.1 Background

ElectraNet has explored electricity supply options for ensuring reliable electricity supply for the Eyre Peninsula. ElectraNet's PACR represents the final step in the application of the Regulatory Investment Test for Transmission (RIT-T) to network and network support options for ensuring reliable electricity supply for the Eyre Peninsula.

The existing 132 kV line serving the Eyre Peninsula has been in service since 1967 and several sections require replacing.

In April 2018, the Australian Energy Regulator (AER) accepted ElectraNet's revenue proposal for replacement works for the line serving the Eyre Peninsula and for network support to provide backup supply to Port Lincoln. The AER's acceptance of that revenue proposal noted that the Eyre Peninsula RIT-T was then on-going, and included a contingent project provision that would allow the determination to be varied if a more efficient option is identified.

ElectraNet's Eyre Peninsula PACR investigates whether there are more efficient supply options for the Eyre Peninsula. It identifies a preferred option that comprises:

- A new double-circuit line from Cultana to Yadnarie that is initially energised at 132 kV with the ability to energise this section to 275 kV in future.
- A new double-circuit 132 kV line from Yadnarie to Port Lincoln.

The PACR concludes that estimated capital cost of the preferred option is $240 million, and that the preferred option will deliver net market benefits of $150 million over 20 years with a new SA-NSW interconnector in place or $140 million over 20 years without a new SA-NSW interconnector in place.

1.2 Frontier Economics' engagement

Frontier Economics has been engaged by the AER to assist in reviewing the economics analysis and modelling undertaken by ElectraNet in support of the Eyre Peninsula PACR. Specifically, we have been engaged to advise on the reasonableness of ElectraNet's:

- ***Inputs and assumptions used in the RIT-T*** – such as the choice of, and justification provided for:
  - Demand forecasts.
  - Unserved energy costs.
  - Plant capital and operating costs.

  - The components of each reasonable scenario used to assess the project, including the inclusion of appropriate ‘committed’ and ‘anticipated’ projects expected to occur over the analysis timeframe.
  - The probability or likelihood attributed each reasonable scenario.
- ***Methodology adopted for assessing net economic benefits*** – such as:
  - Whether a suitable range of credible options has been considered.
  - Whether appropriate market development modelling has been undertaken to properly establish the ‘modelled projects’ arising under each state of the world applicable to each credible option and reasonable scenario.
  - Whether all suitable categories of benefits and costs have been properly taken into account and valued.
- ***Adequacy of any sensitivity analysis*** – to test whether the identification of the preferred option is reasonably robust to changes in key parameters.

1.3 Structure of this report

This report sets out our assessment of the reasonableness of the economic analysis and modelling undertaken by ElectraNet in support of the Eyre Peninsula RIT-T PACR. This report is structured as follows:

- **Section 2** provides our assessment of the methodology adopted for calculating net benefits presented in the PACR.
- **Section 3** provides our assessment of the inputs and assumptions used in the PACR.
- **Section 4** provides our assessment of the adequacy of the scenarios and sensitivity analysis supporting the conclusions in the PACR.
- **Section 5** provides our assessment of the reasonableness of the results and conclusions reached in the PACR.

2 ASSESSMENT OF METHODOLOGY

This section provides an assessment of the methodology that ElectraNet has used to assess the market benefits of the identified options for ensuring reliable electricity supply for the Eyre Peninsula.

2.1 Overview of methodology

2.1.1 Determining the 'base case'

Appendix B of the PACR refers to the RIT-T definition of 'Base case' as "*a situation in which no option is implemented by, or on behalf of the transmission network service provider.*"[1] This definition comes from the National Electricity Rules (NER) clause 5.16.1(c)(1) and so is binding. However, the PACR opts for a 'business as usual' base case instead on the basis that "*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*"[2]. The 'business as usual' base case used in place of the 'do nothing' case incorporates a partial reconductoring of the existing 132 kV line serving the Eyre Peninsula with an estimated cost of around $88m. The use of a base case on which the PADR and PACR's modelling is based takes the benefits attributed to the reconductoring option, i.e. the business as usual case, as given.

Appendix F of the PADR outlines the economic assessment of the reconductoring on which the business as usual case is based, although with some modifications in the PADR and PACR. Table 14 reproduced in **Figure 1** below illustrates the costs and benefits of the reconductoring works. The benefits of the works stem from reduced 'risk costs' – the product of the probability of failure, likelihood of consequence, and the cost of consequence – which were estimated by external consultant AMCL. ElectraNet notes that there are additional benefits to the reconductoring over and above the risk costs presented in the table (for example, avoided fuel consumption).

1 PACR, p 76.

2 The initial economic model provided titled "ElectraNet-IR001-EC.14145,14137 Eyre Economic Model-20170614-v2-Confiden....xlsx" (Initial Economic Model), suggests the USE in states of the world with a single-circuit line is valued at $966,450 per year based on 38.6MWh of unserved energy. This volume of USE is present in both the base case (do nothing) and Option 1 (reconductor). We are unable to interrogate any USE that may appear in the risk cost benefits, as the risk cost (likelihood of consequence multiplied by the cost of consequence) is hardcoded in the model. Therefore, we can't comment on how unacceptable or unrealistic this USE is.

Figure 1: Do nothing vs 'BAU' net benefits

Table 14 – Cost and benefits for options relative to the 'do nothing' case (PV $millions, 2017)[154]

	Costs/benefits	Option 1	Option 1A
Costs	Capital expenditure: line works, project delivery, gen support during works	(47.9)	(29.5)
	Avoided generation support costs	None	None
	Avoided operational expenditure	6.9	5.5
Benefits[155]	'Risk cost reduction'[156] benefit on the Yadnarie to Pt Lincoln 132 kV line	55.8	46.0
	'Risk cost reduction' benefit on the Cultana to Yadnarie 132 kV line	73.2	61.3
Total net present benefits		**88.1**	**83.3**

Source: PADR pg 112

2.1.2 Modelling approach

ElectraNet has engaged HoustonKemp to undertake market modelling to assess the economic benefits of the identified options.

In assessing market benefits ElectraNet and HoustonKemp distinguished between two types of identified options:

- **Standard options** are options that involve a single upfront investment decision.
- **Flexible options** are options that allow optimisation of future investment decisions. The three identified options that include this option to upgrade are Option 4C, Option 4D and Option 5C.

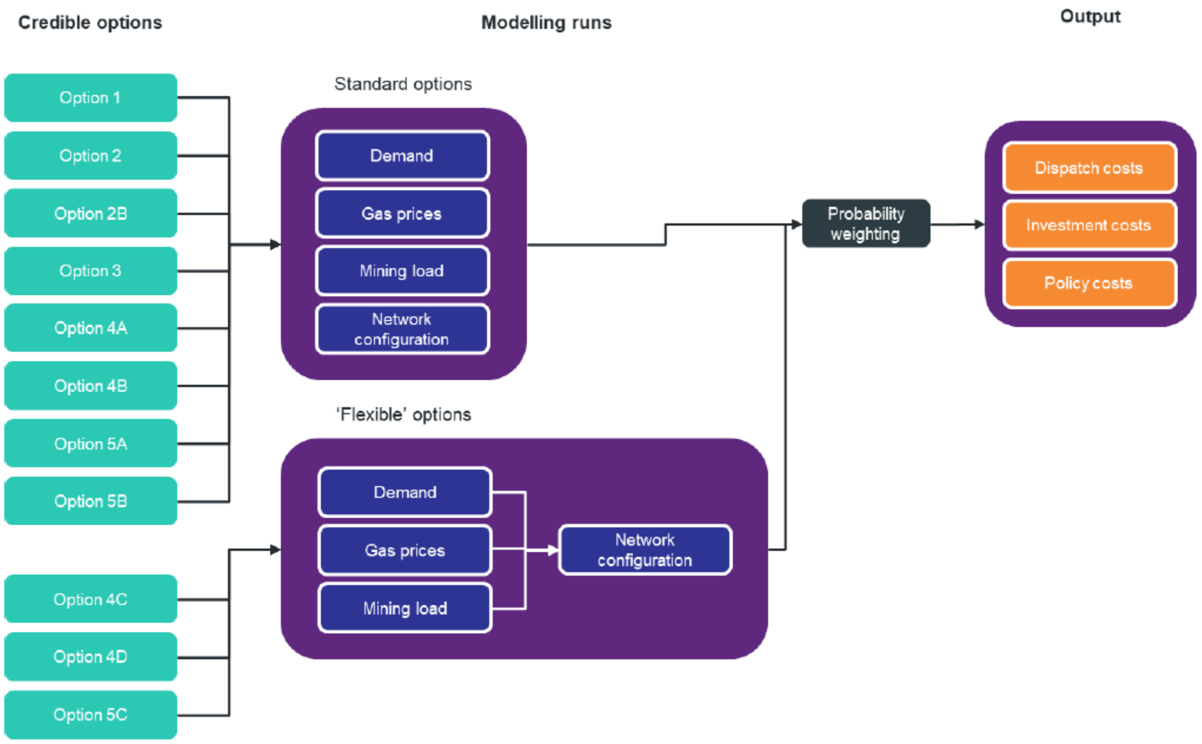
The approach that HoustonKemp adopted to assessing market benefits was different for the standard options and flexible options.

For the standard options, our understanding is that HoustonKemp has applied an electricity market dispatch model to assess market benefits. The market benefits that have been accounted for in this market modelling are changes in fuel consumption in the NEM and changes in other costs for generators. Market benefits for these standard options have been assessed using standard scenario analysis, where different scenarios have included different assumptions for demand, gas prices, mining load and network configuration.

For the flexible options, our understanding is that HoustonKemp has used its electricity market model within the context of a real options framework. The real options framework has been adopted in order to reflect the option value available from the three identified options that involve building additional network capacity now in order to gain the option of upgrading the network at a later date in response to external triggers. Our understanding is that HoustonKemp has constructed a decision tree based on the assumption that decisions about upgrading the network can be made annually, and additional information about demand, gas prices, mining load and network configuration will become available over time. For each outcome on this decision tree, HoustonKemp have used its electricity market model to assess market outcomes. Using these electricity market outcomes, HoustonKemp can then calculate the option value provided by the identified option.

This approach is summarised in **Figure 2**, reproduced from ElectraNet's Eyre Peninsula PACR.

Figure 2: Overview of modelling framework



Source: ElectraNet's Eyre Peninsula PACR, page 47.

ElectraNet has pointed out that in order to make this real options framework tractable, a moderately simplified electricity market model has been applied to facilitate the large number of simulations to be run with the electricity market model.

2.1.3 Credible options considered

ElectraNet has identified and assessed 12 credible options for the PACR; a business as usual base case and 11 options that reflect investment in a wide variety of different network capacities and routes. This set of credible options was expanded by two relative to the PADR in response to submissions to the PADR.

In addition to the 12 credible options considered in the PACR, ElectraNet also considered but did not progress a number of other options because they were not considered to be technically or economically feasible. These other options included consideration of ongoing generation support, battery support and micro-grids.

2.2 Our assessment

2.2.1 Selection of a 'base case'

Our view is that the net benefits of the identified options in the PACR should be assessed against a 'do nothing' case rather than against a 'business as usual' base case that incorporates a partial reconductoring. Since the reconductoring works have not been committed we think the 'do nothing' case should be a case in which the reconductoring is not undertaken.

However, this may make no difference to the conclusions. ElectraNet's analysis in the PACR is assessing the incremental costs and benefits of the identified options relative to the reconductoring case. In doing this, ElectraNet treats 'avoided' reconducting costs as a benefit, but do not treat the reduced risks costs discussed above as a benefit. As long as these reduced risk costs still occur under each of the identified options, and are greater than 'avoided' reconductoring costs, ElectraNet's analysis will not be affected by treating the reconductoring option as the 'do nothing' case.

2.2.2 Market modelling methodology

ElectraNet has provided some detail on the market modelling undertaken on its behalf by HoustonKemp in Appendix G of the PACR.[3] Appendix G makes clear that the market modelling approach is a least cost modelling approach. The modelling results spreadsheet released by ElectraNet includes results for both generation investment and generation dispatch, which suggests that the model is optimising for both investment decisions and dispatch decisions. This is a fairly standard approach to undertaking long-term modelling of investment and dispatch outcomes in the NEM.

Beyond this, ElectraNet has not released, through the PACR, any specific detail on the electricity market modelling approach used by HoustonKemp to assess market benefits.

We have reviewed the investment and dispatch results released by ElectraNet and compared them with comparable modelling results, including AEMO's Integrated System Plan (ISP) modelling. This high level review does not highlight any obvious concerns with the electricity market modelling that HoustonKemp has undertaken (although we do highlight some issues with input assumptions in Section 3).

2.2.3 Real options framework

ElectraNet has provided little specific detail in the PACR on the application of the real options framework that HoustonKemp has used to assess market benefits.

Based on the information that ElectraNet has provided we consider that the rationale for undertaking a real options analysis is sound, since there is likely to be an option value associated with those credible options that incorporate an upgrade option.

Based on the information that ElectraNet has provided we also consider that the overall approach to conducting the real options analysis is sound in the sense that the analysis reasonably accounts for the potential decisions points available and accounts for additional information about key drivers of investment decisions.

[3] Appendix G also contains a summary of key input assumptions that have been used by HoustonKemp, which we discuss in more detail in Section 3.

3 ASSESSMENT OF INPUT ASSUMPTIONS

This section provides an assessment of the input assumptions that ElectraNet has used to assess the market benefits of the identified options for ensuring reliable electricity supply for the Eyre Peninsula.

3.1 Overview of input assumptions

ElectraNet confirms that HoustonKemp has aligned key input assumptions used in its market modelling with those used by AEMO in the modelling for the ISP.

ElectraNet has released an Excel workbook that contains detailed modelling assumptions.

3.1.1 Demand

Demand forecasts are sourced from AEMO's ISP. Forecasts consist of annual sent-out energy (in GWh) and as-generated maximum demand (in MW), for each region.

ElectraNet acknowledges in the PACR that there was an error in the PADR that resulted in demand being modestly over-estimated, but confirm that this error has been rectified in the PACR.

HoustonKemp's electricity market model does not model outcomes for each five-minute dispatch interval or each half-hour settlement interval. Rather, in order to reduce run time their electricity market model identifies a subset of dispatch intervals to model. Specifically, HoustonKemp model 15 representative days and, for each of these representative days, model 6 representative periods. These load blocks have been developed by applying a clustering algorithm to group all days of the year (based on 2016/17 outcomes) into the 15 groups that are statistically most similar in terms of daily profiles for demand, wind output and solar output. For each of these representative days, a clustering algorithm is used to identify 6 load blocks to represent the daily profiles.

Modelling long-term investment decisions using representative load blocks is a common feature of most approaches to modelling the NEM and we do not have an issue with using representative load blocks. However, in our view there are two potential issues with the HoustonKemp approach:

- It is unclear how well the clustering approach adopted by HoustonKemp is able to reasonably represent periods of low wind generation or low solar generation. By grouping days that are similar in terms of each of demand, wind output and solar output there is the risk that none of the representative load outcomes reasonably reflect outcome days (including consecutive days) or low wind and/or low solar generation.
- While modelling long-term investment on the basis of representative demand points is a common approach, we note that investment results from long-term models of this type can then be fed into dispatch models with a more accurate representation of load and output, including dispatch models that include a full half-hourly representation of the year. This is an approach that is likely to lead to a more realistic representation of dispatch decisions, particularly in the presence of intermittent generation and storage. This is an approach that has been adopted by AEMO.

3.1.2 Plant cost assumptions

Capital costs for new generation and storage options, fuel costs for existing and new generation, and fixed and variable operating costs for existing and new generation are all sourced from AEMO's ISP.

3.1.3 Emissions constraints and renewable policies

The modelling accounts for national emissions targets, the Large-Scale Renewable Energy Target and state-based renewable energy targets in Queensland and Victoria. The input assumptions for each of these is sourced from AEMO's ISP.

3.1.4 Unserved energy (USE)

A key driver of market benefit is changes in unserved energy (USE) to customers.

ElectraNet has estimated the expected USE under each investment option and state of the world. ElectraNet expects an amount of USE under the base case, including following severe weather events. ElectraNet expects that this amount of USE will be reduced in all identified options:

- USE will be 80 per cent lower in transmission-related options that do not involve geographically diverse network paths.
- USE will be negligible in transmission-related options that do involve geographically diverse network paths.

In each case USE is valued at $40,733/MWh for residential customers and $15,998/MWh for industrial customers, which is AEMO's latest estimate of the value of customer reliability, adjusted for CPI.

3.1.5 Marginal loss factors (MLFs)

A key driver of differences in modelling outcomes for the credible options and differences across the scenarios and sensitivities is assumptions about marginal loss factors (MLFs). MLF assumptions impact the modelling in the PACR in two ways:

- Directly, as changing the MLF changes the network losses incurred by generation and load sited on the Eyre Peninsula. The PADR suggests[4] these avoided costs are insignificant in magnitude (in the tens of thousands). These avoided costs are not enumerated separately in the PACR; the information on assumed MLFs under each identified option and their response[5] to the information request dated 1 February 2019 (the Information Request) suggests to us that these direct benefits would be much more material in the PACR.
- Indirectly, by changing investment decisions regarding location and timing of new generation and/or interconnection. This effect is significant in the modelled outcome; in their response to the Information Request, they attribute 18% of the wholesale market benefit to this impact for Option 4A. They note that the impact would be lower for the preferred Option 4D.

ElectraNet has published the MLFs that they have assumed for each network configuration and for each scenario relating to new mining loads. These MLFs are based on ElectraNet's internal modelling utilising results from studies on loss factors for wind farms on the Eyre Peninsula commissioned by AEMO.

4 PADR Appendix G (NPV Results), cell L8

5 ElectraNet's response to item 1a suggests that that 18% of the wholesale market benefits in Option 4A are attributable to location and timing of new generation. By inference, the value of losses implied is $4.9m (Option 4A benefit x (1 – 18%) – Option 2 benefit) in the base case with no interconnector, as the increased average output from wind farms is the same in both cases. $4.9m is substantially different to the 'avoided losses' benefits outlined in the PADR of around $40,000-50,000. On reduced transmission losses, the PADR (p54) states the following: "*Differences in expected transmission losses between options are expected to be relatively minor, with the geographically diverse single-circuit options expected to result in slightly less losses. ElectraNet considers that a more detailed estimation of the losses would represent a disproportionate level of analysis, given the limited magnitude of the market benefit associated with losses, and since the precise numbers assumed do not affect the outcome of the RIT-T.*" We cannot explain the difference between the value of losses between the PADR and PACR, but it may be important in determining the preferred option, as discussed in Section 3.2.

These MLFs reflect the fact that under the current network configuration Cathedral Rocks and Mount Millar wind farms are subject to substantial losses, largely because of the high impedance of the current lines back to the 275 kV network at Cultana. ElectraNet notes that any network configuration that leads to an increase in the voltage of the network will result in a reduction of the losses to which these generators are subject.

3.1.6 Relieving constraints on existing wind farms

A key driver of the differences in modelling outcomes between the base case and other credible options is the assumption about the existence of constraints on the existing wind farms on the Eyre Peninsula, which results in the curtailment of output.

ElectraNet has assumed that for all credible options (other than the base case) constraints on the operation of Cathedral Rocks and Mount Millar wind farms will be relieved to the extent than an average of 3.6 MW of additional output from these wind farms will be available.

ElectraNet's PACR states that the estimated market benefits are predominantly driven by the relief of these constraints. However, in response to questions, ElectraNet clarified that the relief of constraints (and improved MLFs) account for the majority of market benefits in all cases, but that changes in generation investment and dispatch from an additional location for renewable generation also provide market benefit in the cases in which the network elements would be operating at, or would be upgradeable to operate at, 275kV. This would seem to account for the fact that, for instance, market benefits under Option 4D are around $40 million while market benefits under Option 2 are around $30 million.

3.1.7 Build limits

ElectraNet's modelling imposes build limits[6] on planting decisions in the NEM. These assumptions are important as they may impact the choice of the preferred option.

The build limits are imposed in three forms:

- On AEMO's Renewable Energy Zones (REZs) in the form of transmission limits with associated augmentation costs, and renewable resource quantities. These assumptions are sourced from AEMO's 2018 ISP.
- On the amount of capacity that can be sited on the Eyre Peninsula, depending on the configuration of the upgraded line and the corresponding mining load. These assumptions come from ElectraNet.
- On the amount of technology able to be built in different regions in any given year. ElectraNet says these assumptions come from both AEMO's 2018 ISP and 2016 NTNDP, although some of the assumptions used date back to the 2013 NTNDP.

These build limits seem to affect the choice of preferred option because they appear to materially affect calculated wholesale market benefits. ElectraNet's response to the Information Request (question 1c) illustrates that the wholesale market benefits of Option 4A (275kV) are substantially higher than the wholesale market benefits of Option 2 (132kV) due to the direct effect of differences in losses (which ElectraNet has said are immaterial) and the indirect effect through increased capacity able to be installed on the Eyre Peninsula, accounting for the majority of the $11.5m difference in benefits. We suspect that the annual build limits (third point above) contribute to additional capacity being sited on the Eyre

[6] These assumptions are outlined in the "N2_Build Limits" tab of Appendix M

Peninsula (rather than elsewhere, where it is constrained by the build limits), and hence increase the wholesale market benefits of the higher-rated options, especially in scenarios with high carbon targets.

3.2 Our assessment of input assumptions

Our view is that the input assumptions that have been relied on by ElectraNet and HoustonKemp have generally come from credible sources and are reasonable. We do have some reservations about specific input assumptions, including the following:

- The coal price assumptions for existing generators in the NEM from AEMO’s ISP are based on a report by Wood Mackenzie that is dated May 2016. Since then the international price of coal has roughly doubled, which raises the prospect that the coal price forecasts should be updated.
- There appears to be no investment option for new hydro plant, including new pumped-storage hydro. New hydro plant may reasonably be expected to form part of the future generation mix.
- As discussed, we have some questions about the ability of the demand clustering approach to reasonably reflect periods of low wind and/or solar generation and to reasonably reflect actual dispatch outcomes.
- The build limits relating to technology limits on a regional level are outdated, originating from the 2016 and prior NTNDPs, and their inclusion is unusual given that the rest of the assumptions generally adhere to the ISP. It appears that the inclusion of the three sets of build limit constraints is the main differentiator between wholesale benefits in the different cases. It is plausible that the outdated NTNDP constraints are what is driving the preference for Option 4D over Option 2. This is discussed further in Box 1.

Box 1: Impact of build limits on the preferred option

In the Information Request, we asked for an intuitive explanation of substantially higher wholesale market benefits in Option 4A relative to Option 2. The intent of the question was to clarify how there can be significant differences in wholesale market benefits when the assumptions that matter most – as stated in the PACR, namely additional assumed wind output – are the same in both cases. ElectraNet's response was that the difference in wholesale market benefits is due to two factors: reduced losses due to changes in the MLF, and "*the additional quantity of new generation that could locate on the Eyre Peninsula under Option 4A relative to Option 2 owing to the increased capacity available on the higher voltage line*". As discussed in Section 3.1.5, the impact of reduced losses is small or negligible, so the majority of the $11.5m difference in benefit in the no interconnector case is attributable to increased capacity available for investment on the Eyre Peninsula. The difference in available capacity for investment between Option 4A and Option 2 is between 650 and 910MW in the case of no SA-NSW interconnect, depending on the mining load. The difference in available capacity for investment between Option 4D (the preferred option) and Option 2 is 100MW, regardless of mining configuration. We expect that this accounts in large part for the $5.8m difference between the market benefits in options 4A and 4D.

It may be the case that the regional annual build limits are driving investment decisions in the model to locate on the Eyre Peninsula, increasing the benefits of configurations that enable this capacity. For example, if new wind is unable to locate in other regions where required due to these annual build limits, the 'next best' option may be to site on the Eyre Peninsula. Without these annual build limit constraints, this wind may be built in other regions where required, resulting in no additional benefit. Option 4D and Option 2 share the same MLF assumptions, but differ in that there is an additional 100MW of new capacity available on the Eyre Peninsula in Option 4D. If Option 4D's wholesale benefit was closer to Option 2, e.g. if additional build capacity on the Eyre Peninsula was not required due to the alleviation of the regional technology constraint, Option 2 would be the preferred option.

We have undertaken a high level comparison of the dispatch outcomes from HoustonKemp's modelling and from AEMO's ISP, and we note some material differences. In particular:

- The modelling from AEMO's ISP results in greater dispatch from utility-scale solar than HoustonKemp's modelling.
- The modelling from AEMO's ISP results in material dispatch from utility-scale storage, while HoustonKemp's modelling apparently has no dispatch from utility-scale storage.

We expect that this difference may come down to the treatment of demand.

However, while we have some reservations about some of the input assumptions that have been relied on by ElectraNet and HoustonKemp, we do not want to overstate these concerns. It may be that our reservations are reasonably dealt with in the modelling. And, in any case, we note that the key result is that there are market benefits associated with reduced USE for customers on the Eyre Peninsula and improved MLFs for wind generators on the Eyre Peninsula. As long as ElectraNet's assumptions about the extent of reduced USE, the extent of improved MLFs and the extent to which constraints on existing wind farms are relieved are reasonable – and we see no reason to think that they are not – then we think it is reasonable to expect that there will be wholesale market benefits associated with the preferred option and we think that the reservations that we have highlighted above would be unlikely to materially affect the estimation of these market benefits.

4 ASSESSMENT OF SCENARIOS AND SENSITIVITIES

This section provides an assessment of the scenarios and sensitivities that ElectraNet has used to assess the market benefits of the identified options for ensuring reliable electricity supply for the Eyre Peninsula.

4.1 Overview of scenarios

ElectraNet defines 'state of the world' assumptions as assumptions that define each 'state of the world' modelled in the option value analysis (ie a low demand world versus a high demand world). We take these 'state of the world' assumptions to define the scenarios that ElectraNet and HoustonKemp have modelled and also take it that these scenarios are modelled both for standard options and flexible options (as indicated in **Figure 2** above).

The state of the world assumptions that ElectraNet and HoustonKemp vary are the following:

- Demand – weak, neutral or strong. Each of these is based on AEMO's ISP.
- Gas prices – low, neutral or high. Each of these is based on AEMO's ISP.
- Mining load – no mining load, Iron Road or Iron Road and other mining loads. Each of these is based on research ElectraNet commissioned from AME.

ElectraNet and HoustonKemp have given each of neutral demand and neutral gas prices a 50% weighting, and given the weak/low and strong/high a 25% weighting each.

The probabilities given to mining load scenarios are based on research by AME. These 'state of the world' assumptions are summarised in **Figure 3**, reproduced from ElectraNet's Eyre Peninsula PACR.

Figure 3: 'State of the world' assumptions

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

Source: ElectraNet's Eyre Peninsula PACR, page 43.

It is not clear to us how these assumptions are treated either in the modelling for standard options or the modelling for flexible options. For instance, it is not clear to us whether the real options analysis could result in a combination of strong electricity demand and weak gas prices, or whether strong electricity demand and strong gas prices are assumed to always occur together.

4.2 Overview of sensitivities

ElectraNet and HoustonKemp have modelled a number of additional sensitivities. These include:

- A future with and without a new interconnector between South Australia and New South Wales.
- A future with 52 per cent national emissions reduction target by 2030, rather than a 28 per cent national emissions reduction target by 2030. This sensitivity is derived from the strong scenario from AEMO's ISP.
- A future with:
  - zero probability of Iron Road being developed and zero probability of other mines being developed
  - 5.8 per cent per annum probability of Iron Road being developed and 1 per cent per annum probability of other mines being developed

  in addition to the mining load state of the world assumptions highlighted in **Figure 3**.
- A future with:
  - 30% higher annual network support costs
  - 30% lower annual network support costs.

- A future with:
  - 15% higher capital costs
  - 15% lower capital costs.
- A future with:
  - a high discount rate of 8.5 per cent
  - a low discount rate of 3.63 per cent

  in addition to the cost assumption of a discount rate of 6 per cent.

ElectraNet concluded that the preferred option – Option 4D – is the preferred option and is net beneficial not just for a central set of key assumptions but also for a range of alternative underlying scenarios and sensitivities.

4.3 Assessment of scenarios and sensitivities

The choice of scenarios and sensitivities should reflect any variables or parameters that are likely to affect the ranking of credible options or the sign of the net economic benefit of credible options.

It is clear from ElectraNet's analysis that many of the scenarios and sensitivities do affect the size of the net economic benefit but, for the most part, do not affect the ranking of the credible options or the sign of the net economic benefit. Based on this, we consider that the scenarios and sensitivities are generally appropriate.

However, focusing on the wholesale market benefits and the avoided unserved energy, we question whether there are other sensitivities that might affect the ranking of credible options or the sign of the net economic benefit. We have noted that the key drivers of wholesale market benefits and avoided unserved energy are assumptions about:

- changes in USE to customers
- differences in assumptions about MLFs
- differences in the assumption about the existence of constraints on the existing wind farms on the Eyre Peninsula.

It is unclear to us whether ElectraNet has considered undertaking sensitivities on these drivers. We expect that the differences in demand that are incorporated in ElectraNet's scenarios would result in differences in USE. However, it is not clear that ElectraNet has assessed whether there are plausible sensitivities for MLFs or constraints on existing wind farms.

Ultimately, we think that this is unlikely to be material to ElectraNet's analysis. As ElectraNet noted in response to suggestions that sensitivities reflecting different emissions policies or renewable policies should be assessed, wholesale market benefits are not particularly significant to the overall economic assessment of the credible options. For this reason, we would expect that even if there are plausible sensitivities for MLFs or constraints on existing wind farms, these sensitivities would not change the conclusions of ElectraNet's analysis.

5 ASSESSMENT OF RESULTS AND CONCLUSIONS

This section provides an assessment of the results and conclusions of ElectraNet's assessment of the market benefits of the identified options for ensuring reliable electricity supply for the Eyre Peninsula.

5.1 ElectraNet's results and conclusions

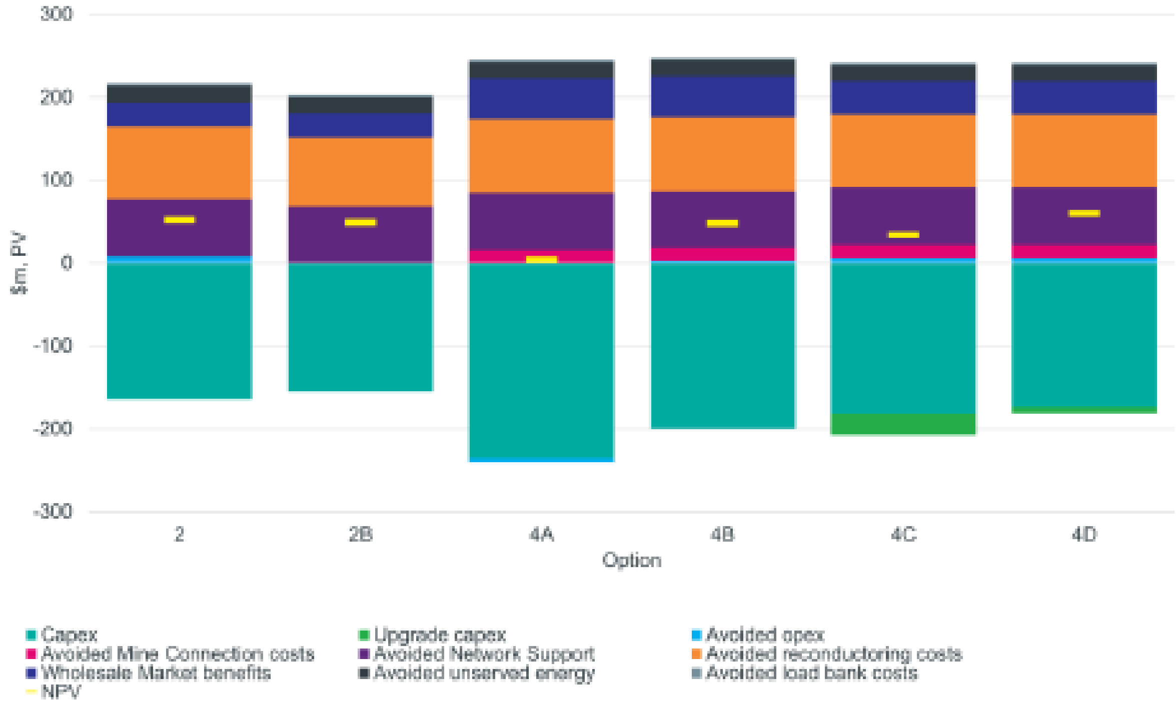
As discussed, ElectraNet has identified and assessed 12 credible options for the PACR; a business as usual base case and 11 options that reflect investment in a wide variety of different network capacities and routes.

As discussed, ElectraNet has assessed each of these 12 credible options against a range of scenarios and sensitivities. Based on this, ElectraNet has concluded that the preferred options is:

- A new double-circuit line from Cultana to Yadnarie that is initially energised at 132 kV with the ability to energise this section to 275 kV in future.
- A new double-circuit 132 kV line from Yadnarie to Port Lincoln.

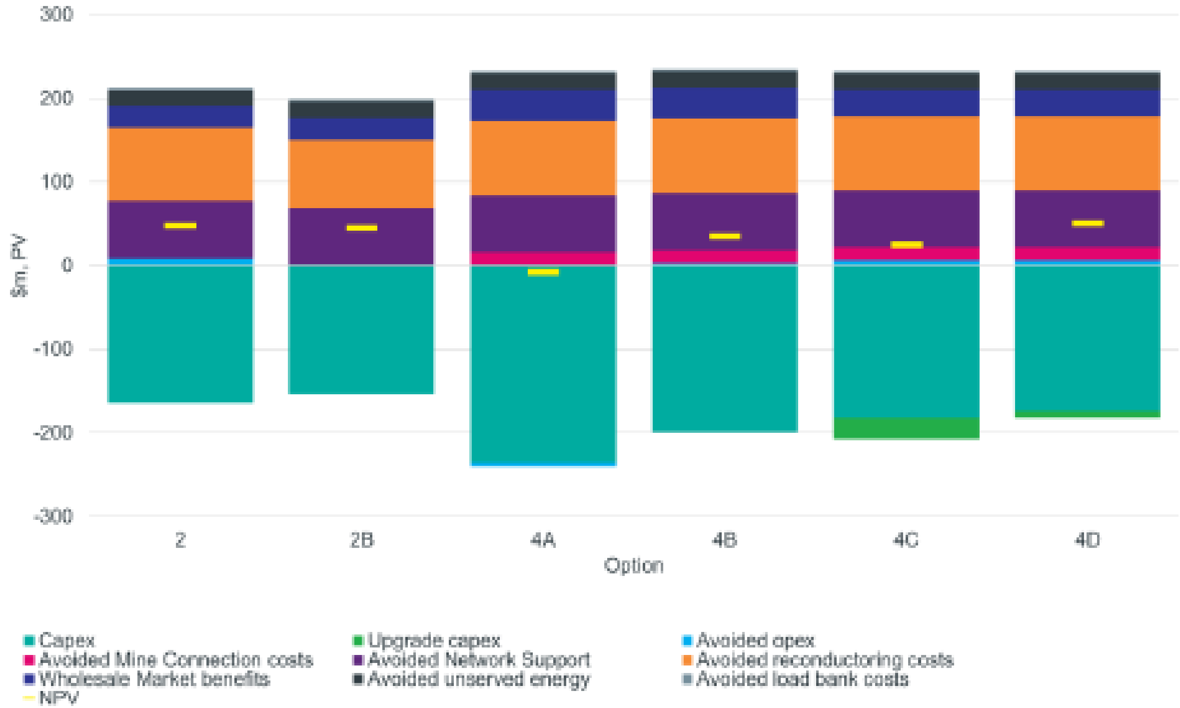
This is referred to as Option 4D. **Figure 4** and **Figure 5** indicate that Option 4D has a net market benefit both with and without a new SA-NSW interconnector, and is the preferred option, both with and without a new interconnector. ElectraNet's analysis also finds that Option 4D has a net market benefit, and is the preferred option for a number of other scenarios and sensitivities.

Figure 4: Breakdown of estimated net market benefits for credible options via Yadnarie under core assumptions – with new SA-NSW interconnector



Source: ElectraNet's Eyre Peninsula PACR, page 57.

Figure 5: Breakdown of estimated net market benefits for credible options via Yadnarie under core assumptions – without new SA-NSW interconnector



Source: ElectraNet's Eyre Peninsula PACR, page 58.

5.2 Our assessment

We have been asked to focus on assessing the approach to modelling the wholesale electricity market that ElectraNet and HoustonKemp have adopted, including the modelling inputs that they have used and the scenarios and sensitivities that they have modelled.

While ElectraNet has not provided a great deal of detail about the approach to modelling the wholesale electricity market that they, and HoustonKemp, have used, in general, we consider that the information they have provided suggests that the approach, inputs, scenarios and sensitivities they have used are reasonable.

We have raised a number of potential issues with the modelling inputs and scenarios, but think that these potential issues are unlikely to materially affect ElectraNet's conclusions. We can see from **Figure 4** and **Figure 5** (and the data underlying these figures) that even if there is no wholesale market benefit Option 4D remains net beneficial. And we do not expect that assuming that there is no wholesale market benefit is a reasonable assumption: as long as ElectraNet's assumptions about the extent of reduced USE, the extent of improved MLFs and the extent to which constraints on existing wind farms are relieved are reasonable – and we see no reason to think that they are not – then we think it is reasonable to expect that there will be wholesale market benefits associated with the preferred option and that reservations that we have highlighted would be unlikely to materially affect the estimation of these market benefits.

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