Lower Eyre Peninsula Reinforcement

RIT-T Project Assessment Draft Report

January 2013

Version 1.0

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Executive Summary

This Project Assessment Draft Report (PADR) has been prepared by ElectraNet in accordance with the requirements of the National Electricity Rules (NER) clause 5.16.4. This PADR represents the second stage of the formal consultation process set out in the NER in relation to the application of the Regulatory Investment Test – Transmission (RIT-T) for the Lower Eyre Peninsula Reinforcement.

ElectraNet notes that the nature and timing of investment on the Lower Eyre Peninsula is heavily dependent on the commitment of new spot loads in the region (e.g. new mining loads). It is this potential commitment of spot load that would drive the need for investment in the near term, rather than reliability requirements for underlying demand growth which are now not expected to need addressing until at least the summer of 2017/18.[1]

The report shows that transmission network augmentation is the most economical solution for future spot load investment scenarios on the Lower Eyre Peninsula of 100 MW or greater.[2]

ElectraNet is publishing this PADR to ensure that the market is fully informed of the current status of potential transmission network developments on the Lower Eyre Peninsula.

However, ElectraNet does not intend to finalise the RIT-T analysis and issue a Project Assessment Conclusions Report (PACR) in the near future. ElectraNet will revisit and progress the analysis in this PADR once financial commitments from a new spot load have been secured or prior to the time at which reliability constraints need to be addressed.

The timing of transmission network augmentation options shown in this PADR is based on the requested timing in the connection enquiries received from new spot load developments.[3] In reality the timing of any augmentation will be dependent on these spot loads making a firm financial commitment and whether they choose to fund pre-construction work ahead of full commitment. Depending on customer commitment to funding pre-construction works and the scope of network augmentation works ultimately required, a transmission network augmentation would likely take 2 - 5 years to complete from the time of customer financial commitment to connect a spot load.

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[1] ElectraNet notes that this date has been revised from the 2013/14 date given in the Project Specification Consultation Report, as a result of an update in SA Power Networks' load forecasts. Also once maintaining reliability requirements to cater for underlying demand growth does become an issue needing to be addressed, it is likely that lower cost non-network options will further defer the need for major transmission augmentation for a number of years.

[2] ElectraNet has also undertaken analysis that indicates that a transmission network augmentation would also be the most economical solution under scenarios where more than 30 MW of spot load located on the Lower Eyre Peninsula.

[3] With the exception of scenario 1 where no spot load is assumed to locate on the Lower Eyre Peninsula, and the timing of investment is determined by reliability requirements.

Identified need

The Eyre Peninsula is a region of South Australia bounded by Whyalla, Port Lincoln and Ceduna. The Lower Eyre Peninsula region has a main radial transmission supply of 132 kV extending from Whyalla to Yadnarie substation (approximately 8.5 km west of Cleve). A radial 132 kV line also extends west to Wudinna and another south to the Port Lincoln substation. Supply to Port Lincoln is supported by a network support agreement with Synergen that allows ElectraNet to call upon the services of three distillate fired gas turbine generators located at Port Lincoln when needed.

Electricity demand on the Lower Eyre Peninsula transmission system has grown steadily over the years as a result of agricultural, residential, commercial, mining and industrial development. The Lower Eyre Peninsula is also experiencing a significant increase in forecast demand associated with mining development and associated infrastructure such as new ports and processing facilities. ElectraNet has received five formal connection enquires to date, covering six separate spot load developments.

These potential changes to demand on the Lower Eyre Peninsula give rise to two main limitations on the area's existing transmission network:

- There is anticipated to be insufficient electricity network infrastructure and network support from the summer of 2017/18 to accommodate future load at Port Lincoln within the reliability standards set out in the South Australian Electricity Transmission Code (ETC); and
- There is currently insufficient electricity infrastructure to accommodate anticipated spot load developments throughout the Lower Eyre Peninsula.

In addition, the age and condition of the existing 132 kV radial line means that replacement of sections of conductor will likely need to be scheduled from 2019 onwards between Yadnarie and Port Lincoln Substations over a period of approximately 10 years. In the longer term replacement of conductor sections between Whyalla and Yadnarie may also be required.

Credible options included in the assessment

The following five options have been included as credible options in the RIT-T assessment:

- Option 1A: A 275 kV double-circuit (600 MVA, N-1) transmission line solution from Cultana to Port Lincoln North, with a 3rd 275 kV (600 MVA) line added between Cultana and Yadnarie when needed;
- Option 1B: A 275 kV double circuit transmission line (1,000 MVA, N-1) from Cultana to Yadnarie plus a 275 kV double circuit transmission line (600 MVA, N-1) from Yadnarie to Port Lincoln North;
- Option 2A: A 275 kV double-circuit (600 MVA, N-1) transmission line solution from Cultana to Port Lincoln North, initially operated at 132 kV, with a 3rd 275 kV (600 MVA) line between Cultana and Yadnarie added when needed;
- Option 2B: A 275 kV double circuit transmission line (1,000 MVA, N-1) from Cultana to Yadnarie plus a 275 kV double circuit transmission line (600 MVA,

N-1) from Yadnarie to Port Lincoln North. All circuits built to 275 kV initially operated at 132 kV; and

- Option 3: Rebuild Cultana to Port Lincoln as a high capacity 132 kV radial line plus on-going generation support at Port Lincoln and on-site generation to supply mining load.

Options 1A, 1B, 2A and 2B also each incorporate a demand response (DR) element and an extension of the current Port Lincoln generation support contract to the summer of 2022/23, under the scenario in which there is no spot load development on the Eyre Peninsula. ElectraNet engaged EnerNOC to investigate the potential for DR on the Lower Eyre Peninsula.

The credible options reflect 'investment strategies', with the precise timing, combination and energising of the network elements included within each option able to be varied depending on the development of future spot load, as reflected in the different reasonable scenarios. For options 1A, 1B, 2A and 2B, the new 275 kV line would be built in close proximity to the existing 132 kV line.

Reasonable scenarios

ElectraNet has adopted four reasonable future scenarios in undertaking the RIT-T analysis. The key parameter varied between the scenarios is the expected level of future spot load in the Eyre Peninsula. As none of these spot loads are currently committed, there remains considerable uncertainty as to the future timing and quantity of spot load development.

The four following scenarios incorporated in the RIT-T analysis are set out below (the weight applied to each scenario is shown in brackets):

- Scenario 1: no spot load and medium demand forecast for Port Lincoln (30%)
- Scenario 2: low (100 MW) spot load and high demand forecast for Port Lincoln (30%)
- Scenario 3: medium (340 MW) spot load and high demand forecast for Port Lincoln (30%)
- Scenario 4: high (610 MW) spot load and high demand forecast for Port Lincoln (10%)

An equal weighting of 30% has been applied to scenarios 1, 2 and 3. ElectraNet considers that the lack of committed status for any of the connection enquiries means that there is no robust basis on which to conclude that a scenario relating to no, low or medium spot load is more likely than another. A lower weight has been applied to the scenario where a high amount of spot mining load requests connection (scenario 4), as it would require all of the formal connection enquires to become committed, as well as additional enquires which are currently more speculative.

Quantification of costs

The costs of Options 1A, 1B, 2A and 2B are predominantly comprised of the network capital expenditure and the associated network operating costs. The only exception is under scenario 1, where there are also costs for a 3 year DR program at Port Lincoln and an extension of the existing generation support contract (which expires in 2018). However, these costs do not form a significant proportion of the overall total.

The overall cost of Option 3 is largely driven by the costs of providing on-site generation to meet mining load, under scenarios where there is additional spot load in the Eyre Peninsula.

The costs associated with on-site generation rise steeply with the quantity of new spot load assumed (and is zero under scenario 1, where there is no additional spot load). Option 3 also includes the cost of additional generators at Port Lincoln throughout the period, as it continues to reflect a radial transmission supply.

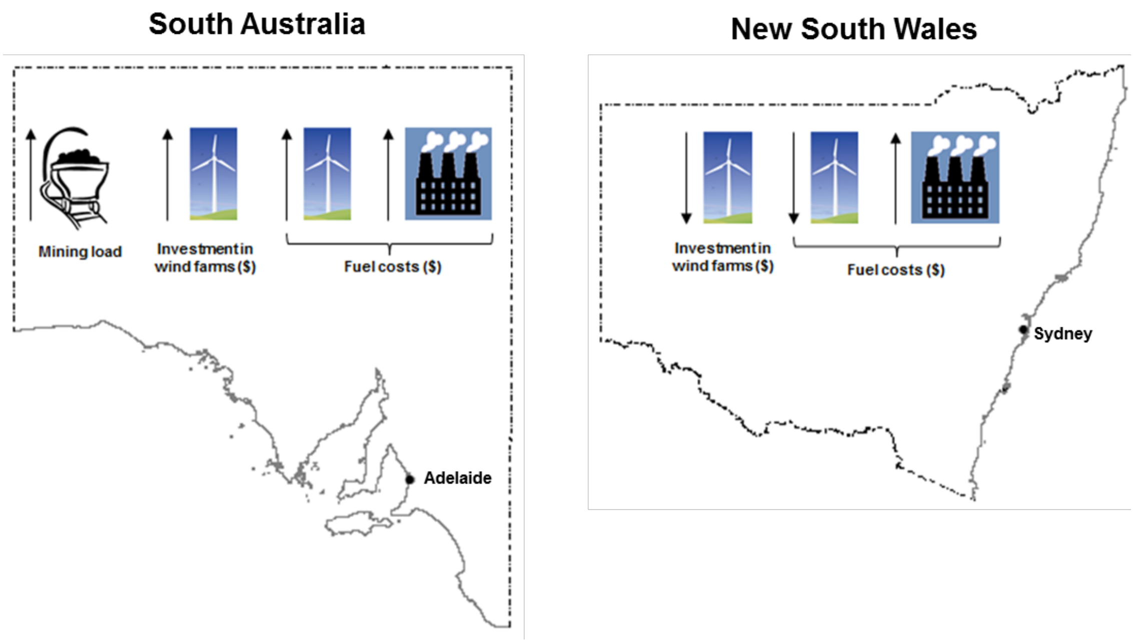
Market benefits

The following categories of market benefits have been quantified as part of the RIT-T assessment:

- Changes in costs for parties other than ElectraNet (ie, changes in generation investment costs);
- Changes in fuel consumption;
- Changes in network losses; and
- Changes in involuntary load shedding.

The key wholesale market impacts associated with the credible options are illustrated in the diagram below:

Figure E-1: Key Wholesale Market Effects



Fuel cost benefits and costs to other parties are the main components of market benefits under scenarios 2, 3 and 4. Changes in these benefit categories are largely driven by the impact of the options on the development of wind generation.

Specifically, in the cases of options 1A, 1B, 2A and 2B, the quantity of wind generation on the Eyre Peninsula is expected to increase, and to displace investment in wind generation that would otherwise have occurred in less efficient locations to meet the Large-scale Renewable Energy Target (LRET). This represents an overall market benefit. However, the increased spot load in South Australia would also result in increased output of other generators in South Australia, in order to meet the higher demand at times when the wind generation is not available. This would result in an increase in fuel costs, compared to the base case, which represents an overall market cost.

Although wind generation has a substantial effect on fuel cost benefits and the costs to other parties, the magnitude of these effects is the same for Options 1A, 1B, 2A and 2B under scenarios 2, 3 and 4. This is a result of the assumption that additional wind generation would rise ‘in step’ with the additional spot load, given constraints on exporting additional wind generation from South Australia.

Market benefits associated with differences in network losses and involuntary load shedding have also been quantified, but have not been found to be material.

Because market benefits are largely unchanged across options (with the exception of Option 3), they play little role in the comparison of credible options in this RIT-T. Instead, differences between the estimated net market benefit of different options are primarily driven by differences in the costs of the different options.

NPV results

The table below shows that the relative ranking of the five options differs across the four scenarios. The option with the highest net market benefit under each option is shown in bold type.

Table E-1: Net Market Benefit and Ranking (in brackets) of Each Credible Option, Under Each Scenario (NPV $m, 2011/12)

Option	Scenario 1: 30%	Scenario 2: 30%	Scenario 3: 30%	Scenario 4: 10%	Weighted Average
1A	-$269 (4)	-$844 (3)	-$2,007 (3)	-$3,161 (4)	-$1,252 (3)
1B	-$288 (5)	-$874 (4)	-$2,037 (4)	-$3,035 (2)	-$1,263 (4)
2A*	-$221 (2)	**-$780 (1)**	**-$1,949 (1)**	-$3,148 (3)	**-$1,200 (1)**
2B*	-$242 (3)	-$818 (2)	-$1,979 (2)	**-$3,022 (1)**	-$1,214 (2)
3	**-$142 (1)**	-$1,496 (5)	-$3,557 (5)	-$6,605 (5)	-$2,219 (5)

**All circuits built to 275 kV to be operated at 132 kV for as long as possible.*

In summary:

- Option 3 is ranked first under scenario 1 but ranked last (with a substantially higher overall net market cost) in all other scenarios.
- Option 2A is ranked second under scenario 1, first under scenarios 2 and 3 and third under scenario 4.
- Option 2B is ranked third under scenario 1, second under scenarios 2 and 3 and first under scenario 4.
- Options 2A and 2B are ranked ahead of Options 1A and 1B under the lower demand scenarios (ie, all scenarios except scenario 4), reflecting the lower cost of those options resulting from their flexibility to defer substation investments in scenarios where there is lower spot load.

The RIT-T assessment is based on the weighted average of the net market benefits across all scenarios. On the basis of the scenario weightings set out above, the NPV analysis shows that the option which is ranked first under the RIT-T is Option 2A: ie, the 275 kV double-circuit 600 MVA line from Cultana to Port Lincoln North, initially operated at 132 kV, with a third 275 kV 600 MVA line between Cultana and Yadnarie added when needed. Option 2B (which is the equivalent option, but with a 1,000 MVA rating) is ranked second. However, the difference in terms of the net market benefit of these two options is only $14m, or 1.2%.

The results of the NPV analysis have also been tested for sensitivity to differences in cost assumptions. The following four sensitivity tests have been undertaken:

1. A 25% reduction in the costs estimated for the lines components of the credible options.
2. A 25% reduction in the assumed costs of on-site generation to supply spot loads.
3. Replacement of only 25% of the existing 132 kV line under Option 3.
4. A 25% increase in the assumed costs of the third 275 kV (600 MVA) line between Cultana and Yadnarie.

All sensitivities yield the same rankings as those in the original NPV analysis.

Proposed preferred option

The RIT-T assessment undertaken for this PADR has highlighted that the preferred option for investment on the Eyre Peninsula is heavily dependent on whether substantial new spot loads connect in the area. There currently remains considerable uncertainty in relation to the connection of such additional spot load, with none of the current connection applications having reached committed status.

Currently the network is expected to meet reliability criteria until 2017/18. As a consequence, there is no immediate pressure from a reliability perspective to finalise the RIT-T analysis. In light of the uncertainty in relation to future spot load developments, ElectraNet considers it prudent to delay the finalisation of the RIT-T process and the publication of the PACR until anticipated spot load developments become committed or prior to the time at which reliability constraints need to be addressed.

The analysis also indicates that by implementing a DR program from 2017/18 and extending the current generation support contract, ElectraNet can delay the time at which it needs to undertake new network investment on the Lower Eyre Peninsula to address reliability concerns to around 2020/21.[4] ElectraNet expects that it would need to finalise this RIT-T assessment by mid-2015 in order to procure demand response and generation support, in the absence of any commitment of major new spot load on the Lower Eyre Peninsula.

ElectraNet is in on-going discussions with a number of potential connection applicants in relation to spot load developments. In the event that one or more of these spot loads do proceed, the analysis presented in this PADR shows that the option which would satisfy the RIT-T is Option 2A; ie, a 275 kV double-circuit 600 MVA line from Cultana to Port Lincoln North with a third 275 kV 600 MVA line between Cultana and Yadnarie added when needed. All circuits built to 275 kV would initially be operated at 132 kV. The timing of operation at 275 kV would be dependent on the staged timing of new spot loads connecting in the Lower Eyre Peninsula.

The timing of transmission network augmentation options shown in this PADR is based on the requested timing in the connection enquiries received from new spot load developments.[5] In reality the timing of any augmentation will be dependent on these spot loads making a firm financial commitment and whether they choose to fund pre-construction work ahead of full commitment. Depending on customer commitment to funding pre-construction works and the scope of network augmentation works ultimately required, a transmission network augmentation would likely take 2 - 5 years to complete from the time of customer financial commitment to connect a spot load.

ElectraNet considers that if substantive load commits in the next 12-18 months, then the underlying assumptions used for the RIT-T analysis in this PADR are likely to remain relevant. However, the longer the delay, the greater the likelihood that the assumptions may require revision, and the analysis may need to be redone and/or the PADR reissued. ElectraNet currently envisages that the analysis in this PADR is likely to remain relevant until mid-2014.

4 ElectraNet is working with SA Power Networks to review the current load forecasts. The dates noted above will be reviewed in the light of the most recent forecasts, prior to any investment being implemented.

5 With the exception of scenario 1 where no spot load is assumed to locate on the Lower Eyre Peninsula, and the timing of investment is determined by reliability requirements.

1. Introduction

This Project Assessment Draft Report (PADR) has been prepared by ElectraNet in accordance with the requirements of the National Electricity Rules (NER) clause 5.16.4. This PADR represents the second stage of the formal consultation process set out in the NER in relation to the application of the Regulatory Investment Test - Transmission (RIT-T) for the Lower Eyre Peninsula Reinforcement.

This PADR:

- Describes the identified need which ElectraNet is seeking to address, together with the assumptions used in identifying this need;
- Describes the credible options that ElectraNet considers may address the identified need;
- Summarises the submissions received on the project specification consultation report (PSCR);
- Provides a quantification of costs and classes of material market benefit for each of the credible options, together with an outline of the methodologies adopted by ElectraNet in undertaking this quantification;
- Provides the results of the NPV analysis for each credible option assessed, together with accompanying explanatory statements; and
- Identifies the credible option which satisfies the RIT-T, and which is therefore the preferred option for investment by ElectraNet.

1.1 Submissions

ElectraNet welcomes written submissions on this PADR.

Submissions are due on or before 1 March 2013.

Submissions should be emailed to consultation@electranet.com.au. Submissions will be published on the ElectraNet website. If you do not want your submission to be publicly available please clearly stipulate this at the time of lodgement.

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

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2. Identified Need

The PSCR discussed in detail the emerging limitations in relation to the existing network on the Lower Eyre Peninsula. This section summarises the earlier discussion in relation to the identified need, and highlights developments since the publication of the PSCR which have impacted on the time at which the limitations are expected to need to be addressed.

2.1 Background

The Eyre Peninsula is a region of South Australia bounded by Whyalla, Port Lincoln and Ceduna. Covering an area of over 230,000 km^2, the Eyre Peninsula supports a population of approximately 59,000 people or 3.6% of South Australia's total population.[6]

2.1.1 Existing electricity supply arrangements

The Lower Eyre Peninsula region has a main radial transmission supply of 132 kV extending from Whyalla to Yadnarie substation (approximately 8.5 km west of Cleve). A radial 132 kV line also extends west to Wudinna and another south to the Port Lincoln substation. The original supply from Whyalla to Port Lincoln was established in 1967. Supply to Port Lincoln is supported by a network support agreement with Synergen that allows ElectraNet to call upon the services of three distillate fired gas turbines generators located at Port Lincoln when needed.

The Lower Eyre Peninsula transmission system is supplied via 275/132 kV substations located at Davenport and Cultana. ElectraNet is currently reinforcing Cultana substation and Whyalla Terminal 132/33 kV substation is currently being rebuilt. Figure 2-1 shows the current Lower Eyre Peninsula transmission network.

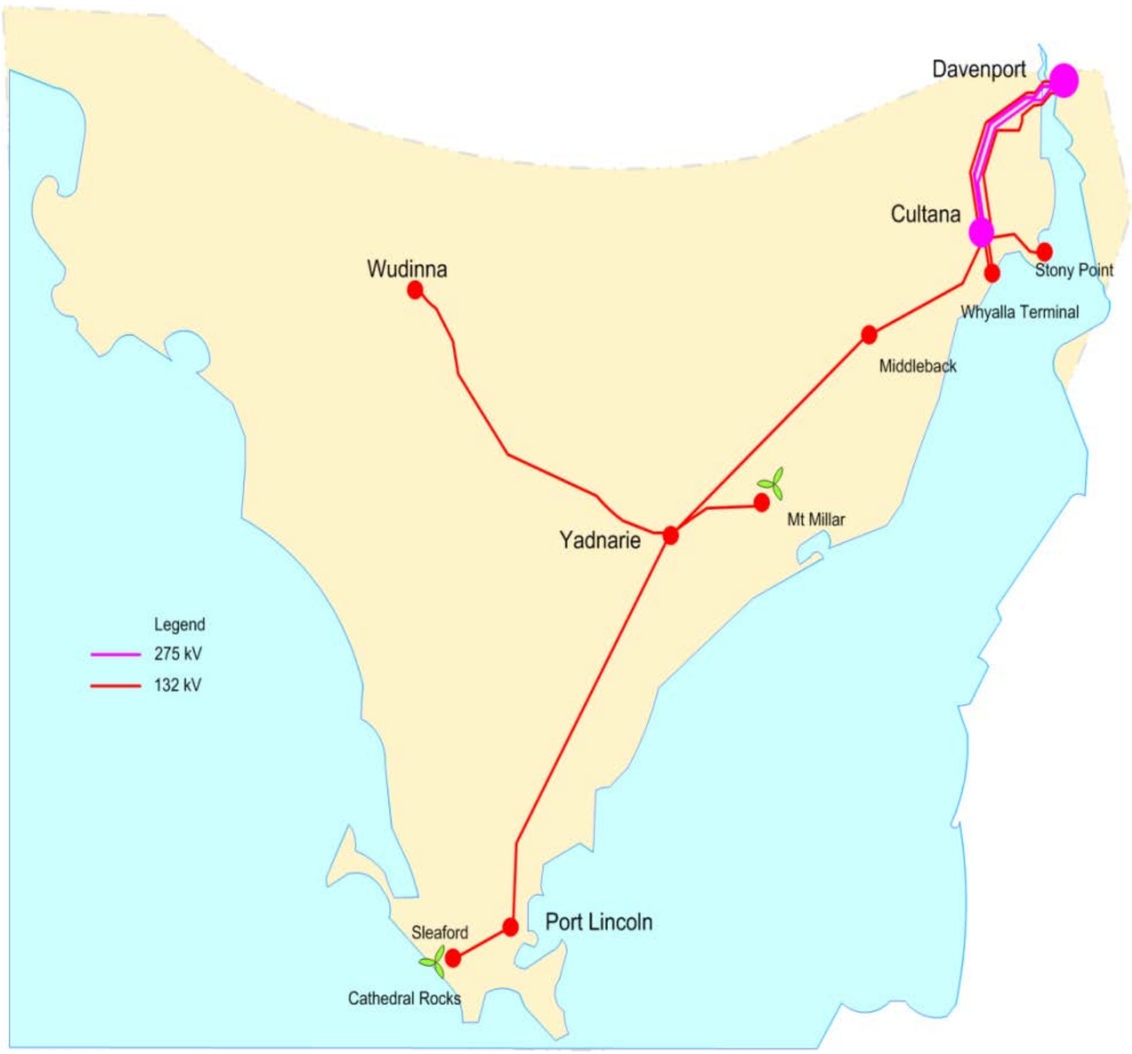
SA Power Networks[7] provides the region's distribution network, which services most of the communities and farms throughout the region.

The region's electricity is derived from both wind and coal resources. This includes wind farms at Cathedral Rocks south of Port Lincoln (supplying 66 MW), and at Mt Millar near Cowell (supplying 70 MW), which supplement the brown coal fired generating stations located at Port Augusta (Northern and Playford B).

[6] Regional Development Australia, *2011 Regional Profile – Whyalla and Eyre Peninsula* pp. 13-15. Available at http://www.eyreregion.com.au/inform/plans-and-strategies.

[7] ETSA Utilities changed its name to SA Power Networks effective 3 September 2012.

Figure 2-1: **Lower Eyre Peninsula Transmission Network**



2.1.2 Development

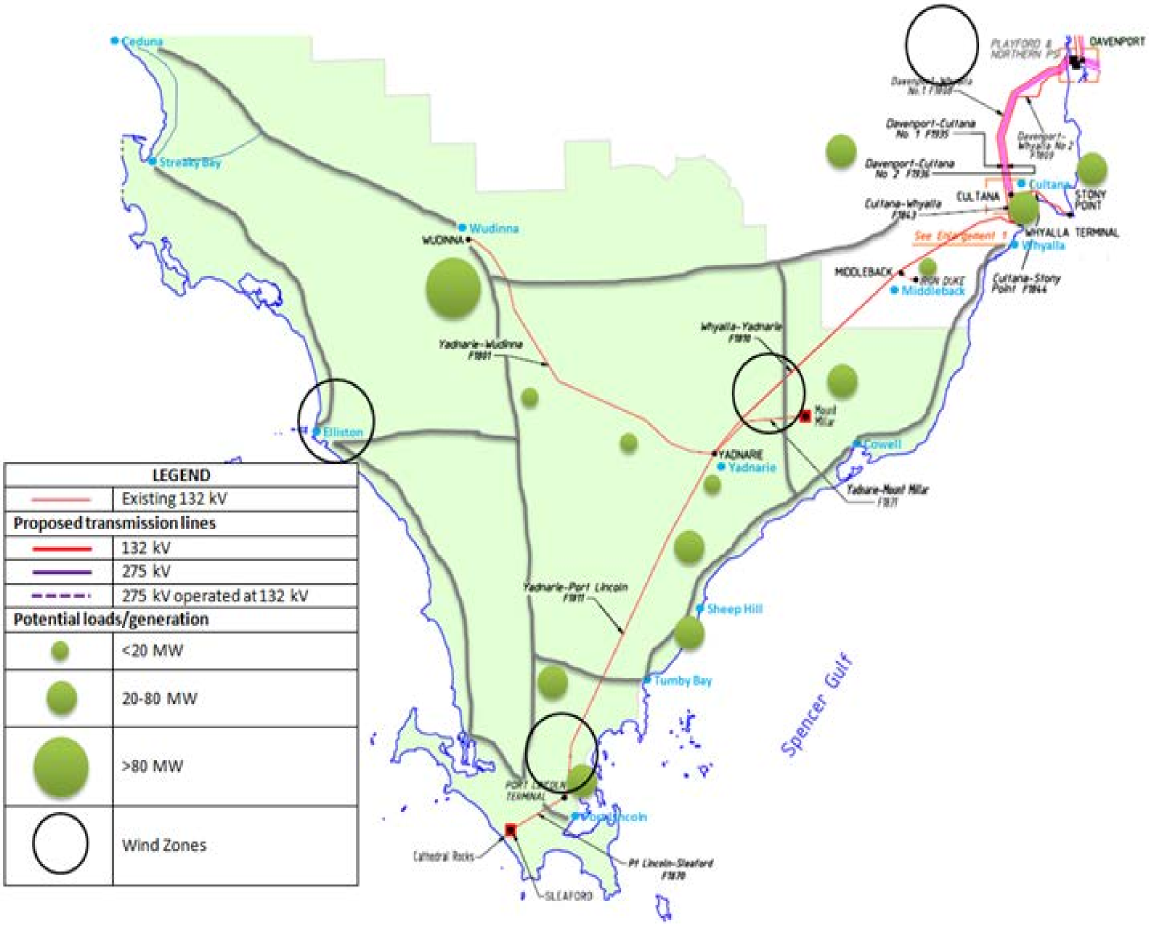
Electricity demand on the Lower Eyre Peninsula 132 kV transmission system has grown steadily over the years as a result of agricultural, residential, commercial, mining and industrial development.

The Lower Eyre Peninsula is also experiencing a significant increase in forecast demand associated with mining development and associated infrastructure such as new ports and processing facilities. The Lower Eyre Peninsula Region has significant mineral and renewable energy resources and is widely recognised as an important new frontier for mineral development in Australia.

The location and total size of prospective loads associated with future mining developments are identified in Figure 2-2. A number of major mining developments have now reached their pre-feasibility stage and have made formal connection enquiries for connection to the transmission network. These developments form the basis for estimating step changes in load growth in the region (as discussed in more detail in section 2.4).

The Lower Eyre Peninsula also possesses high quality wind, wave and solar energy resources, providing substantial renewable generation potential.[8] Currently, constraints on the capacity of the existing transmission network on the Peninsula limits the incentive for new wind generation to connect to the network.

Figure 2-2: Prospective New Load and Wind Generation Developments – Eyre Peninsula



The need to reinforce the existing Eyre Peninsula transmission network to accommodate proposed mining development was highlighted as part of the recommendations the South Australian Resources and Energy Sector Infrastructure Council (RESIC) provided to the South Australian Government in February 2012. Specifically, RESIC recommended:

> "(t)hat a nominated case manager be appointed to work with local mineral resource companies, with Australian Energy Regulator [AER] and with ElectraNet, to assist in accelerating (ahead of the current 2018 [AER] statutory approval) 275 kV augmentation on Eyre Peninsula by the end of 2016, or earlier if this timeframe is appropriate to meet mining industry needs."[9]

In December 2012, the Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE) released its response to the RESIC recommendations and noted that DMITRE has appointed a senior case manager to facilitate the approvals for the

[8] Department of Planning and Local Government, *Eyre and Western Region Plan*, 2011, p.71

[9] DMITRE, *RESIC recommendations to the South Australian Government*, Consultation Paper, Recommendation #3, February 2012, p. 6.

augmentation as well as the interactions between ElectraNet and State Government agencies.[10]

ElectraNet also notes stakeholder comments on this recommendation, that any upgrade of the transmission network cannot solely be about providing electricity to mining ventures and must also integrate the needs of South Australia's growing renewable energy sector.[11]

2.2 Description of the Identified Need

ElectraNet has identified the following limitations in relation to the existing Lower Eyre Peninsula transmission network:

1. Driven by future load at Port Lincoln – there is currently anticipated to be insufficient electricity network infrastructure and network support from 2017/18 to meet the South Australian Electricity Transmission Code (ETC) reliability standards at Port Lincoln.
2. Driven by future total load on the Lower Eyre Peninsula – insufficient electricity infrastructure to accommodate anticipated spot load developments throughout the Lower Eyre Peninsula.

These limitations were discussed in detail in the earlier PSCR.

Since the publication of the PSCR, SA Power Networks has updated its load forecasts. SA Power Networks' latest load forecasts show a reduction in the level of demand growth forecast for Port Lincoln. Under the revised medium demand forecast, the time at which the existing network support arrangements at Port Lincoln will fail to meet the required Category 3 ETC reliability standard has been pushed back to 2017/18, for an outage of the existing transmission line. The PSCR had identified 2013/14 as the date at which the ETC standard would no longer be met. SA Power Networks' revised medium load forecast is discussed in section 2.3 below. ElectraNet also published the revised forecast on its website, together with the implied changes in the non-network requirements under the medium load growth scenario ('Load scenario 1'), to assist responses to the PSCR. [12]

Future spot load development also remains uncertain. Since the publication of the PSCR, no further formal connection enquiries have been received. However, none of the current enquiries have proceeded to committed status, and the expected timing of some of the spot loads has been subject to some minor delays. Section 2.4 discusses future spot load developments. ElectraNet notes that the continuing uncertainty around future spot load developments has been reflected in the RIT-T assessment through the

[10] DMITRE, *South Australian Government response to the RESIC recommendations, Directions Statement*, December 2012, p. 11.

[11] Department for Manufacturing, Innovation, Trade, Resources and Energy, *RESIC recommendations to the South Australian Government Community Consultation: Analysis and Findings*, June 2012, p. 26.

[12] ElectraNet notes further than in its draft decision on ElectraNet's transmission determination (November 2012), the AER expressed the view that the future load forecasts adopted by ElectraNet may be too high. ElectraNet is working with SA Power Networks to review the current load forecasts. The dates by which investment is needed for reliability purposes will be reviewed in the light of the most recent forecasts, prior to any investment being implemented.

adoption of different load assumptions as part of the reasonable scenarios considered in applying the RIT-T. These scenarios are discussed further in section 4.2.

ElectraNet noted in the PSCR that in considering options to address the emerging network limitations, the condition of the existing Cultana – Middleback – Yadnarie – Port Lincoln 132 kV transmission lines must also be taken into account. These lines are now over 45 years old and some components of the transmission line are approaching end of technical life. The NER does not require the RIT-T to be applied to expenditure on replacing or maintaining assets, where that expenditure is not intended to augment the transmission network. However the need to replace these transmission components in the near future, as a result of their condition, is a factor which must be taken into account in developing solutions to address the network limitations identified on the Lower Eyre Peninsula.

Based on condition assessments, replacement of sections of conductor will need to be scheduled from 2019 onwards in order to successively replace corroded conductor in the line segment between Yadnarie and Port Lincoln Substations over a period of approximately 10 years. In the longer term replacement of conductor sections between Whyalla and Yadnarie may be required.

For the purposes of this RIT-T assessment it has been assumed that the existing line will require replacement in 2022/23. However ElectraNet has also undertaken a sensitivity analysis assuming only partial replacement of the existing line. This sensitivity analysis is shown not to affect the RIT-T outcome (see section 6.3.4).

2.3 Future Load Growth: Underlying Trend

Since the publication of the PSCR, SA Power Networks has updated its load forecasts. SA Power Networks' latest load forecasts show a reduction in the level of demand growth forecast for Port Lincoln. Specifically, Port Lincoln loads have been reset back to 2008/09 levels, due to lower than expected actual readings. Large anticipated loads have not progressed as expected (eg Port Boston, Tuna Aqua-culture) due to uncertainty surrounding proposed mining commitment as well as the recent global financial crisis. While the forecast has been reduced back to 2008/09 starting levels, the future growth rate has been maintained.

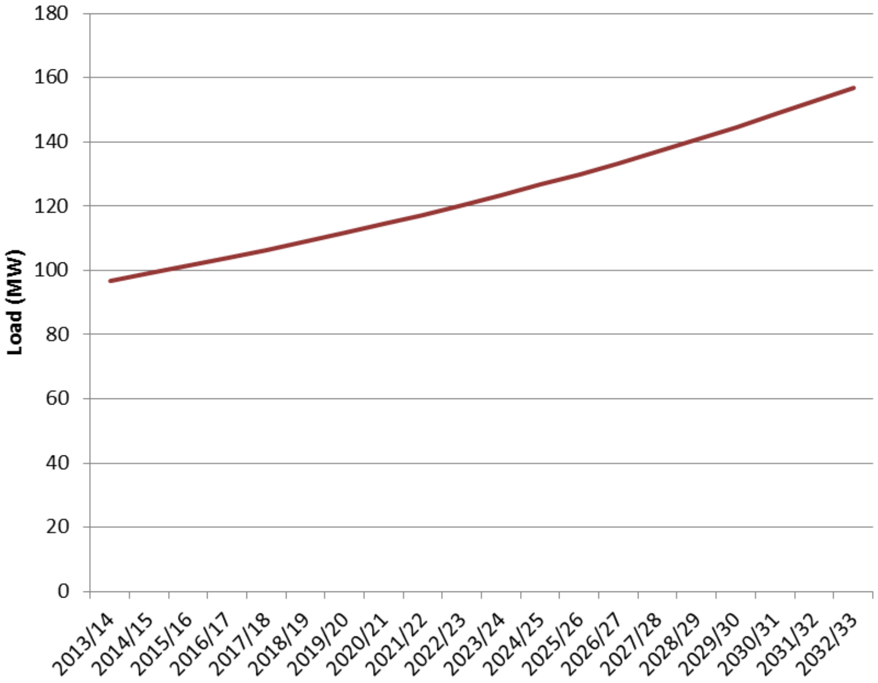
Figure 2-3 shows the updated combined SA Power Networks' medium demand and direct connect customer forecasts for underlying load growth on the Lower Eyre Peninsula. This demand projection excludes any spot load increases associated with new customer developments.

Under the revised underlying demand forecast, the time at which the existing generation at Port Lincoln will fail to meet the required Category 3 ETC reliability standard has been pushed back to 2017/18, for the outage of the existing transmission line.[13] Under the new medium demand forecast, by 2017/18 the load at Port Lincoln will be above the 49 MW contracted generator capacity threshold. This means that the Port Lincoln load may not be supported under N-1 line outage conditions from this date without some load remaining unrestored. This would violate the ETC requirements for the Port Lincoln connection point. The extent of this violation would increase where additional spot loads locate in the vicinity of Port Lincoln and connect to the SA Power Networks distribution system.

[13] The earlier PSCR had identified 2013/14 as the date at which the ETC standard would no longer be met.

In addition, under the ETC ElectraNet is required to have at least the ability to supply 100% of the contracted Agreed Maximum Demand (AMD) with the loss of any transmission line or transformer. The reduction in the underlying load growth forecast means that the time at which the existing network (and network support arrangements) are first expected to no longer be sufficient to meet this requirement is now 2023/24. By this date the medium growth connection point forecast shows that the transformer capacity at Port Lincoln becomes insufficient to meet the anticipated load.[14]

Figure 2-3: Lower Eyre Peninsula Underlying Load Growth – Medium Demand Forecast (2012)



2.4 Potential New Spot Loads

The Lower Eyre Peninsula transmission system has limited or no capacity to accommodate significant additional demand without augmentation.

ElectraNet has received five formal connection enquiries for new load on the Lower Eyre Peninsula to date, covering six separate spot load developments[15] and generally related to the development of major mineral resource deposits. The proposed locations, timing and magnitude of these loads are set out in the following table, in order of their indicative timing. The expected timing of some of these spot loads has been revised slightly since the publication of the PSCR, based on ElectraNet's revised expectations following further discussion with the proponents. In addition, the indicative loads for the Central Eyre Iron Project have been updated to reflect the latest projections provided by Iron Road in its submission to the PSCR.

[14] By 2023/24 the generator connected to the 33 kV bus at Port Lincoln cannot be contracted to provide 'equivalent transformer capacity' as a single generating unit and so does not deliver sufficient reliability to meet the ETC standard.

[15] The connection enquiry from Iron Road relates to two separate spot load developments, both relating to the Central Eyre Iron Project.

Table 2-1:Connection enquires received for major new spot loads on the Lower Eyre Peninsula

Location	Requested timing	Indicative load (MW)
Port Spencer (approx. 20 km north of Tumby Bay)	2015/16	30
Koppio (approx. 45 km north of Port Lincoln)	2015/16	70
Central Eyre Iron Project (approx. 35 km southeast of Wudinna)	2015/16	290
Central Eyre Iron Project (loads in Yadnarie area)	2015/16	50
Bungalow (approx. 15 km north east of Mt Millar)	2016/17	70
Carrow (approx. 45 km south of Yadnarie)	2017/18	50

In addition to these formal enquiries, ElectraNet has continued to receive informal connection enquiries for the Lower Eyre Peninsula.

ElectraNet is presently progressing the above connection enquiries. However the time at which any of these loads will become committed continues to be uncertain. It is possible that not all of the current enquiries will lead to a committed project, and/or that the current expected timeframes will change. It is also likely that new developments will emerge.

3. Submissions to the Project Specification Consultation Report

ElectraNet received five submissions to the PSCR, from:

- Iron Road Limited;
- Meridian Energy Australia;
- TRUenergy;
- EnerNOC; and
- International Power Australia GDF Suez.

The key issues raised in these submissions are discussed in this section. In addition, specific issues raised in submissions are also discussed in the relevant sections throughout this PADR.

3.1 Updated Spot Load Forecast for Central Eyre Iron Project

In its submission, Iron Road provided updated forecasts for the load requirement for its Central Eyre Iron Project.

Iron Road's updated forecast is for a total of 340 MW expected load, comprised of:

- Loads in Yadnarie area (Port and Verran Booster Pump Station): 50 MW; and
- Warramboo mine site: 290 MW.

ElectraNet has taken these updated load projections into account in forming the spot load component of the reasonable scenarios used in the RIT-T analysis, as discussed in sections 2.4 and 4.2.

3.2 Classes of Market Benefits

Meridian Energy noted in its submission that it believed that there is a range of substantial market benefits that would result from the reinforcement of the network in the Eyre Peninsula. In particular it highlighted that the current limitations placed on existing wind farms on the Eyre Peninsula restricts the ability of those wind farms to operate, and consequently deprives the market of substantial amounts of minimal cost renewable energy.

Meridian also noted that a further important market benefit is the likely reduction in losses, particularly in relation to the two existing wind farms located on the Peninsula.

TRUenergy commented that additional market benefits associated with any option, whether through alleviated constraints or reduced transmission losses, should be directly identified and included in the overall assessment.

The classes of market benefit included in this RIT-T assessment and the basis on which they have been quantified are discussed in section 4. In particular, the impact of each of the credible options on network losses has been directly quantified as part of the RIT-T assessment. The impact of the options on the development of wind generation on the Eyre Peninsula has also been considered.

3.3 Scale of Investment Should be Proportionate to Committed Demand

TRUenergy supported ElectraNet's investigation into regulated investment in the context of the need to maintain supply reliability standards as set out in the ETC. However it stressed that the scale of regulated investment needs to be proportionate to the existing level of demand, underlying load growth, the identified and forecast spot load increases and the wider supply options for the region. In particular TRUenergy considered that the extent to which any customer connection enquiries have been proven or progressed through to the application stage, an offer to connect, or a financial commitment should strongly inform the probabilities associated with the load growth scenarios used in the RIT-T assessment.

In the light of SA Power Networks' revised (lower) demand forecast, TRUenergy also considered that further investigation into the technical and economic feasibility of alternative, lower cost options seems reasonable. In particular it suggested that the staged development of high capacity 132 kV lines may represent a more appropriate outcome under some of the demand forecast scenarios.

ElectraNet notes that the RIT-T assessment is conducted over a range of potential reasonable scenarios, reflecting parameters that are considered likely to affect the outcome of the assessment. For the scenarios considered for this RIT-T, the level of future spot load development is a key parameter. The RIT-T has therefore been conducted over a range of alternative scenarios, reflecting different spot load developments.

ElectraNet agrees with TRUenergy that the extent to which future spot load requirements have been confirmed and reflected in a financial commitment is a key consideration in informing the weightings that should be attached to each scenario. This is discussed further in section 4.2.1 below.

ElectraNet also considers it prudent to delay finalisation of the RIT-T analysis and the publication of the PACR for as long as possible in order to provide more time for the spot loads to reach committed status. ElectraNet considers that this approach provides the most appropriate means of limiting the risk that augmentation of the network on the Lower Eyre Peninsula is not sized sufficiently to support demand from future mining activities.

3.4 Factors Affecting the Timing of Investment

TRUenergy requested that ElectraNet clearly articulate how the following factors are likely to influence the proposed timing of the investment options: the performance and condition of the existing Eyre Peninsula assets, SA Power Networks revised demand forecasts, AEMO's National Demand forecasting outcomes, and the expected operation of Alinta Energy's Flinders Power Station.

Section 2.2 has already discussed the impact of SA Power Networks' revised demand forecast in pushing back to 2017/18 the time at which the ETC standard at Port Lincoln is expected to no longer be met. That section also highlighted that ElectraNet currently expects that the condition of the existing network will also require replacement of some sections, although this timing continues to be subject to further, detailed condition assessment. For the purposes of this RIT-T assessment it has been assumed that the existing line will require replacement in 2022/23.

ElectraNet does not expect that the lower electricity demand forecasts reported in AEMO's 2012 National Electricity Forecasting Report[16] will affect the timing of the identified need for investment on the Lower Eyre Peninsula. The specific spot load developments expected are the key driver for the timing of investment, and are independent of the AEMO forecasts. Outside of these spot load developments, underlying load growth in the region is based on farming and fishing activities, both of which may be less subject to any economic downturn.

In relation to the earlier announcement of the seasonal operation of Alinta's Playford power station (one of the two power stations comprising Alinta Energy's Flinders Power Station), ElectraNet notes that recent communication between ElectraNet and Alinta indicates that this is unlikely to be a long-term operating strategy. Moreover, ElectraNet does not consider that the material classes of market benefit for this RIT-T are affected by the assumptions made in relation to the operation of Playford.

3.5 Variations to Network Options

Iron Road proposed a number of variations to the network options set out in the PSCR. In summary, the variations proposed by Iron Road were:

- To locate the proposed 275/132 kV substation at Verran, rather than at Yadnarie West; and
- To route the proposed 275 kV line from Yadnarie West to Port Lincoln via Iron Road's proposed port facility.

Iron Road suggests that locating the substation at Verran (16 km from Yadnarie West) would have the benefit of utilising the proposed Iron Road utilities corridor. ElectraNet considers that the exact location of the proposed substation would be a matter for detailed project design, which would need to take into account the needs and location of existing load and wind generators in the area, as well as the Iron Road and Centrex developments. Therefore, ElectraNet has continued to assume for the purpose of this PADR that the substation would be located at Yadnarie West.

Iron Road's recommendation to route the 275 kV line from Yadnarie so that it passes its proposed ports facility as well as the proposed Centrex development at Carrow is based on its view that this is likely to lower the total cost of investment between Yadnarie West and Port Lincoln and also between Yadnarie West and Iron Road's proposed port. ElectraNet notes that the cost of the connection between Yadnarie West and the proposed port would be incurred by Iron Road as part of its connection costs. Iron Road proposes in its submission that the revised routing could be undertaken as a 'regulated or non-regulated' 132 kV transmission line, and suggests that this approach would reduce TUOS charges for all future customers in the Eyre Peninsula.

ElectraNet considers that undertaking the RIT-T on the basis of options which incorporate a direct routing from Yadnarie West to Port Lincoln remains the most relevant approach. Where Iron Road continues to prefer a line routing which would go via its proposed port facility, then it would be open to it to agree this alternative with ElectraNet as part of its connection negotiations, with the difference in costs between the two routings being treated as a non-regulated service.

[16] AEMO, *2012 National Electricity Forecasting Report (NEFR),* June 2012.

3.6 Non-network Options

EnerNOC in its submission identified itself as a proponent for a demand management (DM) solution to provide sufficient capability to continue to meet the ETC standard at Port Lincoln.

International Power Australia GDF Suez (IPR) also put forward non-network (generation) options to meet both the near-term and the medium to long-term forecast demand in the Eyre Peninsula. IPR wholly owns Synergen Power Pty Ltd which operates the existing Port Lincoln Power Station which presently provides contracted network support services to ElectraNet in relation to the ETC standard at Port Lincoln.

IPR noted that it is willing to work with ElectraNet to:

- Negotiate an uplift of the contracted capacity of the Port Lincoln Power Station (via the addition of a fourth generating unit) to provide a sufficient level of network support through to 2020/2021 to meet the ETC standard at Port Lincoln; and
- Provide brownfield and/or greenfield generation solutions at some or all of Port Lincoln, Yadnarie and Wudinna, in order to meet the medium to long-term spot load requirements.

IPR noted that it believes that a non-network solution is the most cost effective solution for the Lower Eyre Peninsula.

These non-network components have been included in the credible options considered as part of this RIT-T, as discussed in section 5.

4. Description of Methodology

This section provides a summary of the methodology adopted for the RIT-T assessment, including a description of the methodologies adopted for estimating the market benefits, a description of the reasonable scenarios considered and a summary of key assumptions.

Section 6.2 provides a further description of the approach adopted to quantifying each of the material categories of market benefits.

4.1 Detailed Description of Methodologies

4.1.1 Analysis period

The RIT-T analysis has been undertaken over a 20 year period, from 2013/14 to 2032/33.

ElectraNet considers that a 20 year period is appropriate in order to adequately assess the impact of the alternative credible options on future market benefits.

4.1.2 Discount rate

A discount rate of 10% (real, pre-tax) has been adopted in undertaking the NPV analysis, for all credible options. This discount rate represents a reasonable commercial discount rate, appropriate for the analysis of a private enterprise investment in the electricity sector, as required by the RIT-T.[17] ElectraNet notes that the adoption of a 10% discount rate is in line with the approach set out in the Grid Australia Cost-Benefit Handbook.

ElectraNet has 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 6.13%, as reflective of the regulatory WACC[18] and an upper bound discount rate of 13%. The change in the discount rate was not found to affect the ranking of the credible options under the RIT-T, and so has not been incorporated into additional reasonable scenarios for the RIT-T analysis.[19] The results of this sensitivity analysis are provided in Appendix F.

4.1.3 Modelling market benefits

The RIT-T requires that in estimating the magnitude of market benefits, a market dispatch modelling methodology must be used, unless the TNSP can provide reasons why this methodology is not relevant.[20]

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[17] AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph14.

[18] This is the lower bound scenario for the discount rate, specified in the RIT-T paragraph(15)(g). The estimate of the regulatory WACC (real, pre-tax) that would apply to ElectraNet is based on the AER's April 2012 final determination for Powerlink.

[19] This approach is consistent with that set out in the AER's RIT-T Guidelines, p. 26. The results of this sensitivity analysis are provided in Appendix F.

[20] AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 11.

ElectraNet has not adopted a market dispatch modelling approach to estimating the market benefits for this RIT-T, as it would involve a disproportionate level of resources, given the limited difference in the relative impact of the credible options on the wholesale market. Rather, an alternative approach to estimating the impact on the wholesale market and the pattern of generation investment for each of the options considered has been adopted, which requires substantially less resources but still provides sufficient quantification for the purposes of ranking the credible options under this RIT-T. This approach is consistent with the AER's RIT-T Application Guidelines and the RIT-T Handbook published by Grid Australia.

Specifically, the following categories of market benefits have been quantified on the basis of a technical study undertaken by SKM:

- Changes in network losses; and
- Changes in unserved energy (USE).

In terms of market benefit categories driven by the impact of each credible option on the operation of the National Electricity Market (NEM), ElectraNet considers that the material categories of market benefit for this RIT-T are:

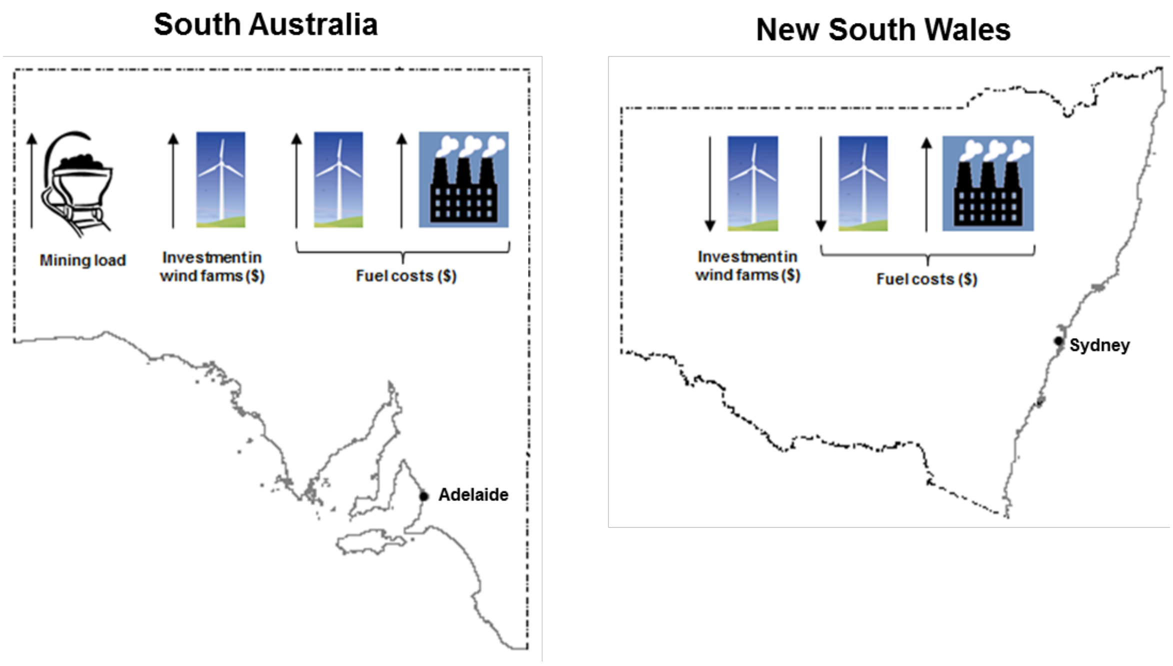
- Impact on the costs for parties other than ElectraNet (ie, changes in generator investment costs); and
- Changes in fuel consumption (ie, generation dispatch costs).

For these two market benefit categories, the impact of the credible options is likely to arise primarily in relation to the extent that they facilitate an increase in the quantity of wind generation developed on the Eyre Peninsula. This additional wind generation is likely to displace investment in wind generation that would otherwise have occurred in less-efficient locations in order to meet the LRET, resulting in an overall capital and operating cost benefit in the NEM. For the purposes of this RIT-T assessment, this alternate location has been assumed to be New South Wales (NSW). This assumption is based on previous market modelling undertaken by ElectraNet.

In addition, although output from the additional wind generation would meet part of the additional spot load on the Eyre Peninsula, there would also be an increase in the output of other generators in South Australia, in order to meet the increased spot load at times when the wind generation is not available. This would also be coupled with an increase in the output of non-wind generation in NSW, as a consequence of the lower level of new wind generation locating in that state.

These key wholesale market effects are illustrated in Figure 4-1 below.

Figure 4-1: Key Wholesale Market Effects



ElectraNet notes that these wholesale market effects only apply under scenarios where additional spot load is assumed to locate on the Eyre Peninsula and only for credible options that can accommodate additional wind generation connecting to the network.

In quantifying these key NEM impacts, ElectraNet has adopted an approach that:

- Does not assume any change in the current constraint on exports of wind generation from South Australia;[21]
- Assumes new wind generation on the Eyre Peninsula rises 'in-step' with the mining spot load assumed to locate on the Eyre Peninsula, in order to supply that spot load;[22]
- Estimates the lower capital and operating costs of wind generation able to locate on the Eyre Peninsula as opposed to the 'state of the world' where there is no network augmentation in the Eyre Peninsula and wind generation locates in NSW to meet the LRET;

[21] ElectraNet notes that there is currently an overall limit of around 1050 MW on the amount of additional wind generation that can be accommodated in South Australia without any expansion of export capacity (ROAM Consulting, *Assessing the Capacity of Commercially Profitable Wind Generation in South Australia*, 15 September 2011, p. 17). Further, ElectraNet notes that there are new wind generation projects in the Mid-North region that are expected to go ahead irrespective of the Lower Eyre Peninsula Reinforcement. For the purposes of this RIT-T, ElectraNet has assumed that these projects will 'use-up' the overall current limit on the amount of wind generation that can be accommodated in South Australia without expansion of export capacity.

[22] Additional wind generation can locate on the Eyre Peninsula even in the absence of any increase in export capacity, provided that there is also additional mining load locating on the Peninsula. That is, both wind generation and load could increase 'in-step'.

- Estimates the higher fuel consumption costs in South Australia resulting from an increase in generation output to meet the higher spot load, at times when the wind generation is not available.
- Estimates the higher fuel consumption costs in NSW resulting from an increase in non-wind generation output to replace the lost output from the wind generation that is now assumed to locate in the Eyre Peninsula

ElectraNet also considered whether increases in spot load of the magnitude included as part of this RIT-T would necessitate the building of new conventional generation in South Australia over and above the assumed new wind generation. ElectraNet notes that many South Australian generators are currently offline or operating at historically low capacity factors. ElectraNet's modelling showed that total demand (including each of the three respective assumed spot load plantings discussed in section 4.2 below) would exceed system capacity for only a few hours each year. Demand-side management (including potentially from the mines themselves) could therefore potentially completely remove the need for new generators.

Finally, for those scenarios in which the credible options are in place prior to the end of 2018, ElectraNet has estimated the avoided operating costs under the current generation support contracts at Port Lincoln.

A more detailed description of how ElectraNet has estimated each class of material market benefit is provided in section 6.2 below.

4.2 Description of Reasonable Scenarios

The RIT-T analysis is required to incorporate a number of different reasonable scenarios, which are used to estimate market benefits. The RIT-T states that the number and choice of reasonable scenarios must be appropriate to the credible options under consideration. The choice of reasonable scenarios must reflect any variables or parameters that are likely to affect the ranking of the credible options (where the identified need is reliability corrective action).[23]

The expected level of future demand in the Eyre Peninsula is a key parameter that may affect the ranking of credible options under this RIT-T assessment. As discussed in section 2.4, ElectraNet has received five formal connection enquires to date, covering six separate spot load developments. Additional spot load development is also likely to affect the underlying rate of demand growth in the Port Lincoln area, as a result of the increase in economic activity. However, since none of these spot loads are currently committed, there remains uncertainty as to the future timing and quantity of spot load development.

In order to assess the impact on the RIT-T outcome of differences in future spot load development and the underlying forecast of demand at Port Lincoln load growth, ElectraNet has therefore identified four alternatives:

1. No spot load, medium demand forecast for Port Lincoln, Wudinna and Yadnarie
2. 100 MW spot load, high demand forecast for Port Lincoln and medium demand forecast for Wudinna and Yadnarie

[23] AER, *Final Regulatory Investment Test for Transmission,* June 2010, version 1, paragraph 16.

3. 340 MW spot load, high demand forecast for Port Lincoln and Wudinna and medium demand forecast for Yadnarie
4. 610 MW spot load and high demand forecast for Port Lincoln, Wudinna and Yadnarie

These alternatives reflect different assumptions about which of the spot load development may proceed, and the timing of those developments, as summarised in Table 4-1.

Table 4-1: Alternative Spot Load Assumptions

Spot Load Assumption	Description
100 MW	Port Spencer – 30 MW (2015/16) and Koppio - 70 MW (2015/16). These spot loads reflect two of the five formal connection enquiries received to date.
340 MW	Wudinna – 290 MW (2015/16) and Yadnarie – 50 MW (2015/16). This scenario reflects one[24] of the five formal connection enquiries received by ElectraNet to date.
610 MW	All of the five spot loads received by ElectraNet to date (ie, a total of 560 MW) plus a further 50% of further potential spot loads, based on additional informal enquiries.

The total MW load forecast for each year (as a result of both underlying demand growth and new spot loads), under each of the four load scenarios described in the above table is set out in Appendix C.

ElectraNet considers that the 340 MW spot load assumption represents a 'medium' spot load assumption. It reflects only one of the five formal connection enquiries received by ElectraNet to date. However in terms of the total MW of spot load, it represents around 60% of the total 560 MW covered by all five of the formal connection enquiries. The other spot load assumptions can be considered as representative of a 'low' and 'high' case for spot load development.

ElectraNet has coupled each of these alternative load scenarios with assumptions about other parameters to develop four reasonable scenarios for this RIT-T, as summarised in Table 4-2 below.

Table 4-2: Summary of Parameters Under Each Reasonable Scenario

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Spot mining load on the Eyre Peninsula	0 MW	100 MW	340 MW	610 MW
Port Lincoln demand forecast	Medium	High	High	High
Discount rate	10%	10%	10%	10%

[24] Note that this one connection enquiry (Iron Road) covers both of the two spot loads identified above.

4.2.1 Weighting of scenarios

The following weights have been applied to each of the four reasonable scenarios included as part of this RIT-T:

- Scenario 1 (no spot load): 30%
- Scenario 2 (low spot load): 30%
- Scenario 3 (medium spot load): 30%
- Scenario 4 (high spot load): 10%

The key differences between the scenarios relate to the amount and location of additional mining spot load. As discussed above, the scenarios have been based on connection enquires received to date. However none of these enquires has proceeded to committed status.

For the purposes of the RIT-T assessment in this PADR, ElectraNet has therefore given equal weight to the scenarios in which: no mining spot load requests connection (scenario 1); a low amount of spot load requests connection (scenario 2: 100MW); and a medium amount of spot load requests connection (scenario 3: 340MW). ElectraNet considers that there is currently no robust basis on which to conclude that any one of these scenarios is more likely than the others.

The scenario where a high amount of spot mining load requests connection (scenario 4: 610MW) has been given a lower weight than the other three scenarios. ElectraNet considers this scenario to be less likely than the other spot load scenarios, as it would require all of the formal connection enquires to become committed, as well as additional enquires which are currently more speculative.

4.3 Classes of Market Benefits Not Expected to be Material

The following categories of market benefit are not expected to be material for this RIT-T assessment:

- Changes in ancillary services costs;
- Competition benefits;
- Changes in voluntary load curtailment;
- Changes in LRET penalties; and
- Changes in non-related network investment.

ElectraNet notes that in the PSCR it identified that changes in ancillary services costs were unlikely to be material for this RIT-T. Since publication of the PSCR, further assessment undertaken by ElectraNet has highlighted that several other 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 this conclusion are set out below in relation to each of the relevant categories of market benefit.

In addition ElectraNet does not consider that at this stage the calculation of option value is material to this RIT-T assessment. However, ElectraNet intends to keep the potential materiality of option value for this RIT-T under review in light of further development in future reasonable scenarios.

4.3.1 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 being considered for the Lower Eyre Peninsula. However FCAS costs are relatively small compared to total market costs, 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. 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 (NCAS) and System Restart Ancillary Services (SRAS) 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.

4.3.2 Competition benefits

ElectraNet notes that competition benefits are net changes in market benefit arising from the impact of the credible option on participant bidding behaviour and that TNSPs are required as part of the RIT-T to consider competition benefits as a class of potential market benefits which could be provided by a credible option.

However, ElectraNet also notes that none of the credible options considered addresses 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 market modelling. For this reason ElectraNet has not estimated any competition benefits as part of this RIT-T assessment.

4.3.3 Voluntary load curtailment

Voluntary load curtailment is when customers agree to reduce their load, typically once pool prices reach a certain threshold or based on another trigger, e.g. network loading. Customers usually receive a payment for agreeing to reduce load in these circumstances. ElectraNet notes that 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 in particular 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.

ElectraNet considers 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. Since this benefit depends on the impact that each credible option is assumed to have on the wholesale market, estimating this benefit would require market dispatch modelling. ElectraNet considers that this would represent a disproportionate level of analysis, given the limited magnitude of the benefit expected.

However, ElectraNet notes that a number of credible options included in this RIT-T include a demand response (DR) component, which assumes some of the largest electricity users on the Lower Eyre Peninsula enter into a program to voluntarily curtail their load during peak times. This DR component is outlined in more detail in section 5.6 below.

4.3.4 LRET penalties

For the purposes of this RIT-T, ElectraNet has assumed that the Large-scale Renewable Energy Target (LRET) is met in full and so has not estimated the costs of any penalties payable for a failure to meet the LRET. ElectraNet notes that the assumption that the LRET will be met is consistent with that adopted in other RIT-T assessments, including the joint ElectraNet-AEMO assessment of upgrades to the Heywood interconnector.

ElectraNet notes that, even if it was assumed that the LRET was not met and that LRET penalties were payable, the magnitude of the penalties relative to the other costs and benefits included in the RIT-T assessment means that they would be unlikely to affect the RIT-T outcome, and so would not be material for this RIT-T.

4.3.5 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.

ElectraNet does 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. Therefore, ElectraNet has not estimated any market benefits associated with the timing of any non-related network investments as part of this RIT-T assessment.

4.3.6 Option value

ElectraNet notes the AER's view that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change and the credible options considered by the TNSP are sufficiently flexible to respond to that change.

ElectraNet also notes the AER's view that appropriate identification of credible options and reasonable scenarios captures any option value, thereby meeting the NER requirement to consider option value as a class of market benefit under the RIT-T. As discussed in section 4.2, ElectraNet has incorporated several reasonable scenarios in conducting the RIT-T analysis, which reflect differences in the future level of expected spot load development, amongst other factors.

For this RIT-T assessment, the estimation of any option value benefit over and above that already captured via the scenario analysis in the RIT-T would require a significant modelling assessment. At this stage of the assessment, ElectraNet considers that the additional modelling would be unlikely to affect the outcome of the analysis, and so would be disproportionate. ElectraNet therefore has not estimated any additional option value market benefit as part of the quantification of market benefits presented for the RIT-T assessment at this stage.

ElectraNet will continue to monitor and assess the materiality of modelling option value as part of this RIT-T going forward, particularly in the light of any changes made to the reasonable scenarios included in the analysis following the firm commitment of additional spot load.

5. Credible Options to Address the Identified Need

The following five options have been considered as potential credible options in the RIT-T analysis:

- Option 1A: A 275 kV double-circuit (600 MVA, N-1) transmission line solution from Cultana to Port Lincoln North, with a 3rd 275 kV (600 MVA) line added between Cultana and Yadnarie when needed;
- Option 1B: A 275 kV double circuit transmission line (1,000 MVA, N-1) from Cultana to Yadnarie plus a 275 kV double circuit transmission line (600 MVA, N-1) from Yadnarie to Port Lincoln North;
- Option 2A: A 275 kV double-circuit (600 MVA, N-1) transmission line solution from Cultana to Port Lincoln North, initially operated at 132 kV, with a 3rd 275 kV (600 MVA) line between Cultana and Yadnarie added when needed;
- Option 2B: A 275 kV double circuit transmission line (1,000 MVA, N-1) from Cultana to Yadnarie plus a 275 kV double circuit transmission line (600 MVA, N-1) from Yadnarie to Port Lincoln North. All circuits built to 275 kV initially operated at 132 kV; and
- Option 3: Rebuild Cultana to Port Lincoln as a high capacity 132 kV radial line plus on-going generation support at Port Lincoln and on-site generation to supply mining load.

Options 1A, 1B, 2A and 2B also each incorporate demand response (DR) and an extension of the current Port Lincoln generation support, under scenario 1 (in which there is no spot load development on the Eyre Peninsula). This is discussed further below (section 5.6).

5.1 Overview

The PSCR set out at a high level two credible network options to address the identified need on the Eyre Peninsula.

Subsequent to publishing the PSCR, ElectraNet has further refined these credible options. Specifically, the two options included in the PSCR have both been divided into two variants, reflecting two different capacity ratings on the 275 kV double circuit transmission line between Cultana and Yadnarie, ie, 600 MVA (Options 1A and 2A, with a 3rd 275 kV (600 MVA) line added as needed, depending on the scenario) and 1,000 MVA (Options 1B and 2B).

An additional option (Option 3) has also been included in the analysis. This option includes the rebuilding of the Cultana to Port Lincoln transmission line as a high capacity 132 kV radial line. Since this option remains a radial solution, on-going network support at Port Lincoln is also required, in order to meet the ETC requirement throughout the assessment period. Option 3 also includes the establishment of various 'on-site' generators to serve mining loads assumed to locate on the Eyre Peninsula under reasonable scenarios 2, 3 and 4 (as outlined in section 4.2 above). Specifically, under this option these mines are assumed to operate their own on-site dedicated mining generation, rather than drawing their electricity needs from the grid.

ElectraNet notes that the credible options continue to reflect 'investment strategies', with the precise timing, combination and energising of the network elements included within each option able to be varied depending on the development of future spot load, as reflected in the different reasonable scenarios.

The timing of transmission network augmentation options shown in this PADR is based on the requested timing in the connection enquiries received from new spot load developments.[25] In reality the timing of any augmentation will be dependent on these spot loads making a firm financial commitment and/ or agreeing to fund necessary pre-construction work ahead of full commitment. Depending on customer commitment to funding pre-construction works and the scope of augmentation works required, a transmission network augmentation would likely take 2 - 5 years to complete from the time of customer financial commitment to connect a spot load.

The remainder of this section provides a more detailed description of each of the five credible options included in the RIT-T assessment.

5.2 Option 1A

Under this option a 275 kV double circuit (600 MVA, N-1) transmission line is constructed between Cultana and Yadnarie with the establishment of a 275/132 kV substation at Yadnarie. Additionally, under scenario 4 a 3rd 275 kV single circuit (600 MVA, N-1) transmission line is constructed between Cultana and Yadnarie, when required to meet the higher loads.

A 275 kV double circuit (600 MVA, N-1) transmission line is also constructed between Yadnarie and Port Lincoln North, establishing a 275/132 kV substation at Port Lincoln North (in the proximity of Koppio) and connecting the existing Port Lincoln substation by way of a double circuit 132 kV line.

As the additional anticipated spot loads request connection, new substations and transmission lines would be constructed. Specifically:

- A third 200 MVA 275/132 kV Yadnarie transformer (under scenario 4); and
- A new spot load located near Wudinna (ie, scenarios 3 and 4) would require: (i) a new double circuit, strung on one side only (600 MVA) 275 kV transmission line from the Yadnarie to Wudinna East Substations; and (ii) the construction of a new 275/132 kV substation at Wudinna East.

Further, under all scenarios, a new 275/132 kV substation would be built around Middleback in 2022/23, to address asset condition concerns.

All new 275 kV lines will be built in close proximity to existing lines, ie, they do not require running new, parallel corridors.

Option 1A also requires a number of reactive support elements to maintain voltage levels along the network. These elements are comprised of different capacitor banks throughout the Peninsula depending on the scenario as well as a -100 + 100 MVAr static VAR compensator (SVC) at Yadnarie under scenario 3 and 4.

[25] With the exception of scenario 1 where no spot load is assumed to locate on the Lower Eyre Peninsula, and the timing of investment is determined by reliability requirements.

Option 1A is depicted in Figure 5-1. The commissioning date and cost of each of the elements of the Option 1A investment strategy under the four scenarios is summarised in Table 5-1. Annual operating costs for the network components have been estimated at 2% of the network capital cost, consistent with the Grid Australia RIT-T Handbook.

Figure 5-1: Option 1A: 275 kV transmission solution

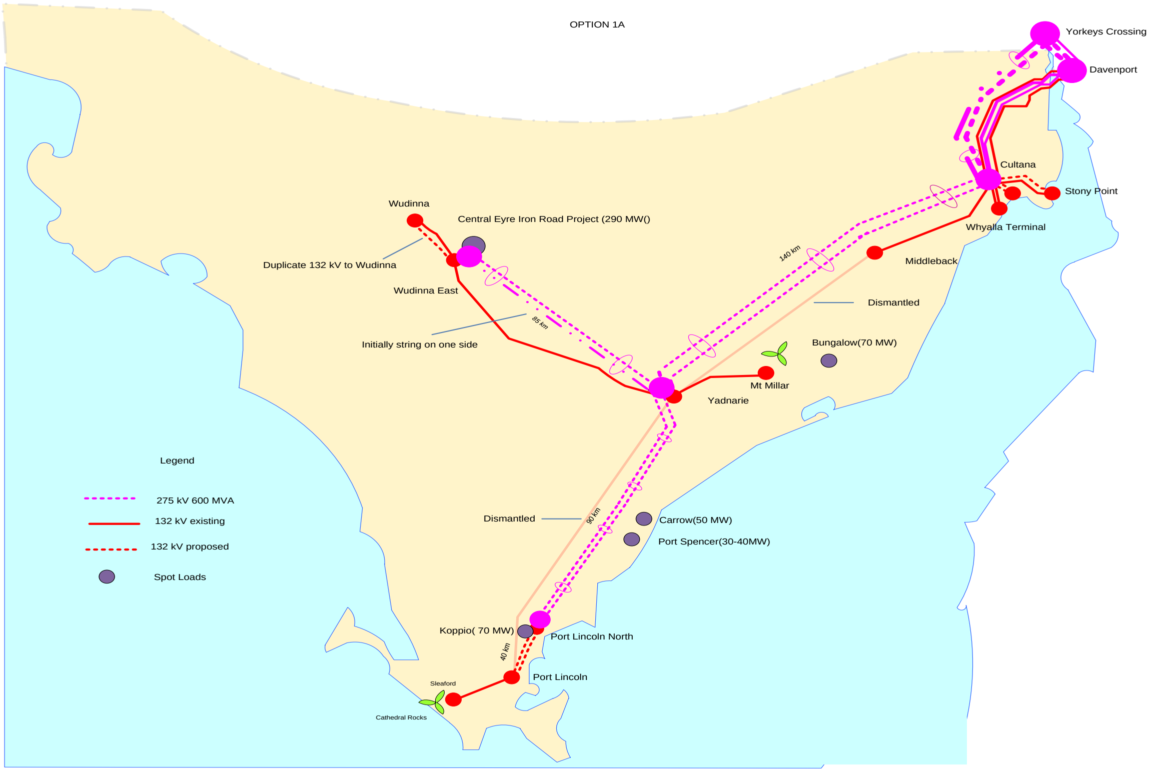


Table 5-1: Timing and costs of the network components of Option 1A under each load scenario

Technical Characteristics of Option 1A	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	**Estimated cost ($m)**	**Estimated year of commissioning**	**Estimated cost ($m)**	**Estimated year of commissioning**	**Estimated cost ($m)**	**Estimated year of commissioning**	**Estimated cost ($m)**
- Build a double circuit 275 kV Line between Cultana and Yadnarie with a line capacity of 600 MVA per circuit (single sulphur conductor) - Cultana substation works to allow for 2 new 275 kV line exits and 2 reactors - New 275/132 kV substation at Yadnarie	2020/21	235 15 78	2015/16	235 15 78	2015/16	235 15 78	2015/16	235 15 78
- Construction of a 3rd single circuit (600 MVA, N-1) 275 kV transmission line between Cultana and Yadnarie	-	-	-	-	-	-	2016/17	199
- Construction of a new double circuit (600 MVA, N-1) 275 kV transmission line from the Yadnarie to Port Lincoln North Substations (approximately 90km) - New 275/132 kV substation at Port Lincoln North - New double circuit (200 MVA, N-1) 132 kV transmission line from the Port Lincoln North to Port Lincoln Substations (approximately 40km)	2020/21	153 54 51	2015/16	153 54 51	2015/16	153 54 51	2015/16	153 54 51
- Construction of a new double circuit, strung on one side only (600 MVA) 275 kV transmission line from the Yadnarie to Wudinna East Substations (approximately 85km) - New 275/132 kV substation at Wudinna East	-	-	-	-	2015/16	121 45	2015/16	121 45

Technical Characteristics of Option 1A	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)
- A third 200 MVA 275/132 kV Yadnarie transformer	-	-	-	-	-	-	2016/17	10
- New 275/132 kV substation at Middleback	2025/26	24	2022/2023		2022/2023	24	2022/2023	24
- 1x25 MVAr cap bank at Port Lincoln	-	-	2016/17 2020/21 2026/27	4 4 4	2016/17 2025/26	4 4	2028/29	4
- 2x50 MVAr cap bank at Port Lincoln	-	-	-	-	-	-	2015/16	9
- 4x50 MVAr cap banks at Wudinna	-	-	-	-	2015/16	15	2015/16	15
- 1x25 MVAr cap bank at Cultana	- -	- -	2016/17 2029/30	5 5	- -	- -	- -	- -
- 2x50 MVAr cap bank at Cultana	-	-	-	-	2015/16	11		
- 1x100 MVAr cap bank at Cultana	-	-	-	-	-	-	2015/16 (x2) 2017/18 2025/26	11 5 5
- SVC (-100 + 100 MVAr) at Yadnarie	-	-	-	-	2015/16	20	2015/16	20
- 1x100 MVAr cap bank at Yadnarie	- - -	- - -	- - -	- - -	- - -	- - -	2015/16 2018/19 2026/27	5 5 5
Total lines costs ($ 2011/12)		**$439**		**$439**		**$560**		**$759**
Total substations costs ($ 2011/12)		**$171**		**$171**		**$216**		**$226**
Total reactive power costs ($ 2011/12)		**-**		**$22**		**$54**		**$84**

Technical Characteristics of Option 1A	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)
TOTAL ($ 2011/12)		**$610**		**$632**		**$830**		**$1,069**

5.3 Option 1B

Option 1B is a variant of Option 1A. The primary difference is that under Option 1B, the 275 kV double circuit transmission line between Cultana and Yadnarie is constructed at 1,000 MVA (rather than 600 MVA). This higher capacity line is sufficient to meet the anticipated spot load under all reasonable scenarios, such that a 3rd 275 kV transmission line between Cultana and Yadnarie is not required during the assessment period.

In addition, as with Option 1A:

- A 275/132 kV substation at Yadnarie is required.
- A 275 kV double circuit (600 MVA, N-1) transmission line is constructed between Yadnarie and Port Lincoln North, establishing a 275/132 kV substation at Port Lincoln North (in the proximity of Koppio) and connecting the existing Port Lincoln substation by way of a double circuit 132 kV line.
- A third 200 MVA 275/132 kV Yadnarie transformer is constructed under scenario 4.
- Under all scenarios, a new 275/132 kV substation would be built around Middleback in 2022/23, to address asset condition concerns.

Further, as with Option 1A, new spot load located near Wudinna (ie, scenarios 3 and 4) necessitates the construction of a new double circuit, strung on one side only 275 kV transmission line from Yadnarie substation to a new Wudinna East substation and the construction of a new 275/132 kV substation at Wudinna East. However, the 275 kV line is built to 1,000 MVA specifications under Option 1B.

As with Option 1A, all new 275 kV lines will be built in close proximity to existing lines, ie, they do not require running new, parallel corridors.

Option 1B also requires a number of reactive support elements to maintain voltage levels along the network. These elements are comprised of different capacitor banks throughout the peninsula depending on the scenario as well as a -50 + 50 MVAr SVC at Yadnarie under scenario 3 and a -100 + 100 MVAr SVC at Yadnarie under scenario 4.

This option is depicted in Figure 5-2 below. The expected commissioning date and cost of each of the network elements of the Option 1B investment strategy under the four scenarios is summarised in Table 5-2. Annual operating costs for the network elements have been estimated at 2% of this capital cost, consistent with the Grid Australia RIT-T Handbook.

Figure 5-2: Option 1B: 275 kV transmission solution

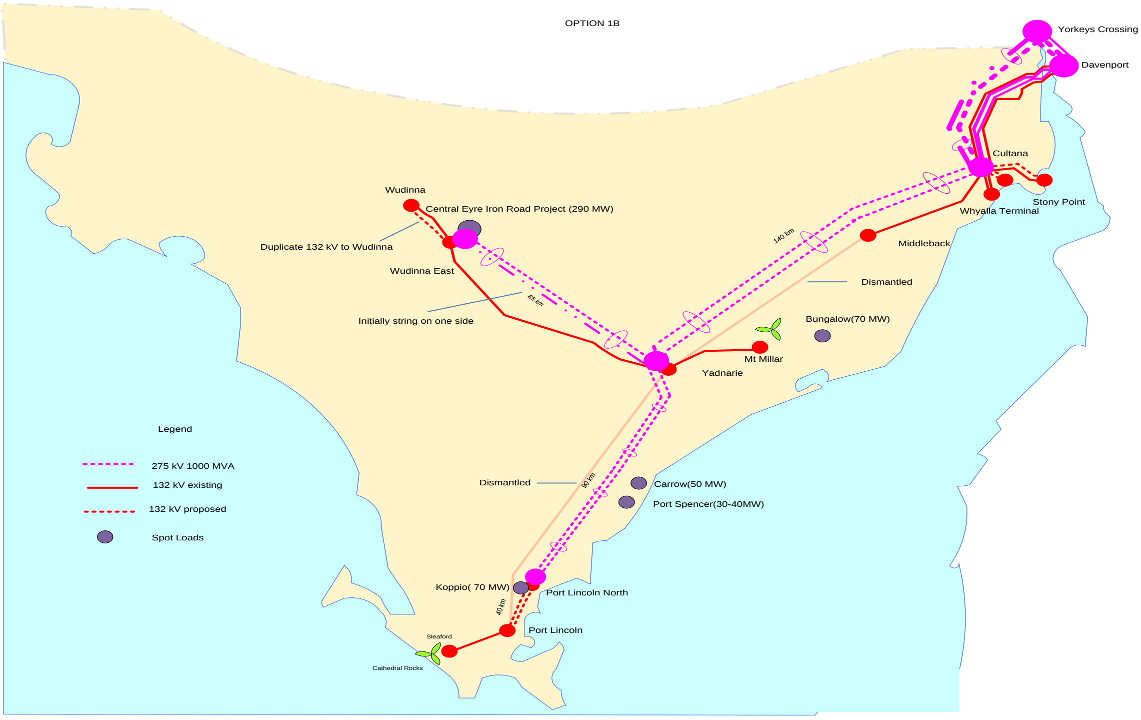


Table 5-2: Timing and costs of the network components of Option 1B under each load scenario

Technical Characteristics of Option 1B	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)
- Construction of a new double circuit, high capacity (1,000 MVA N-1), twin conductor 275 kV transmission line from the Cultana to Yadnarie Substations (approximately 140km) - New 275/132 kV substation at Yadnarie	2020/21	292 78	2015/16	292 78	2015/16	292 78	2015/16	292 78
- Construction of a new double circuit (600 MVA, N-1) 275 kV transmission line from the Yadnarie to Port Lincoln North Substations (approximately 90km) - New 275/132 kV substation at Port Lincoln North - New double circuit (200 MVA, N-1) 132 kV transmission line from the Port Lincoln North to Port Lincoln Substations (approximately 40km)	2020/21	153 54 51	2015/16	153 54 51	2015/16	153 54 51	2015/16	153 54 51
- Construction of a new double circuit, strung on one side only (1,000 MVA) 275 kV transmission line from the Yadnarie to Wudinna East Substations (approximately 85km) - New 275/132 kV substation at Wudinna East	-	-	-	-	2015/16	121 45	2015/16	121 45
- A third 200 MVA 275/132 kV Yadnarie transformer	-	-	-	-	-	-	2017/18	10
- New 275/132 kV substation at Middleback	2025/26	24	2022/2023	24	2022/2023	24	2022/2023	24

Technical Characteristics of Option 1B	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)
- 1x25 MVAr cap bank at Port Lincoln	-	-	2016/17 2021/22 2028/29	4 4 4	2016/17 2025/26	4 4	2028/29	4
- 2x50 MVAr cap bank at Port Lincoln	-	-	-	-	-	-	2015/16	9
- 4x50 MVAr cap banks at Wudinna	-	-	-	-	2015/16	15	2015/16	15
- 1x25 MVAr cap bank at Cultana	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-
- 2x50 MVAr cap bank at Cultana	-	-	-	-	2015/16	11		
- 1x100 MVAr cap bank at Cultana	-	-	-	-	-	-	2015/16 (x2) 2018/19 2027/28	11 5 5
- SVC (-50 + 50 MVAr) at Yadnarie	-	-	-	-	2015/16	19	-	-
- SVC (-100 + 100 MVAr) at Yadnarie	-	-	-	-	-	-	2015/16	20
- 1x100 MVAr cap bank at Yadnarie	-	-	-	-	-	-	2016/17	5
- 1x50 MVAr cap bank at Yadnarie	-	-	-	-	-	-	2028/29	5
Total lines costs ($ 2011/12)		**$496**		**$496**		**$617**		**$617**
Total substations costs ($ 2011/12)		**$156**		**$156**		**$201**		**$211**
Total reactive power costs ($ 2011/12)		**-**		**$12**		**$53**		**$79**
TOTAL ($ 2011/12)		**$652**		**$664**		**$871**		**$907**

5.4 Option 2A

Under this option a double circuit 275 kV transmission line (600 MVA, N-1) is constructed between Cultana, Yadnarie and Port Lincoln North – initially energised to 132 kV.

The two primary sections of line (ie, Cultana-Yadnarie and Yadnarie-Port Lincoln North) remain operated at 132 kV for as long as possible, until the level of load requires either or both sections to be operated at 275 kV.

Table 5-3 below illustrates when each of the three primary sections of the Lower Eyre Peninsula transmission network are built and when they are energised at either 132 kV (black) and/or 275 kV (red).

Table 5-3: Option 2A – Timing of 132 kV or 275 kV operation

Network section	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Cultana to Yadnarie	2020/21 -	2015/16 2023/24	- 2015/16	- 2015/16
Yadnarie to Port Lincoln North	2020/21 -	2015/16 -	2015/16 -	2015/16 2017/18
Yadnarie to Wudinna East	-	-	- 2015/16	- 2015/16

Where the lines are energised to 275 kV, new 275/132 kV substations would be constructed. However in scenarios where operation at 275 kV can be delayed, the need for these substations is also delayed. Specifically:

- Under scenario 1, there would be no need initially for the 275/132 kV substations either at Yadnarie or Port Lincoln North, resulting in a reduction of initial capital investment of about $132 million, compared with Option 1A.
- Under scenarios 2 and 3, there would be no need for the 275/132 kV substation at Port Lincoln North, resulting in a reduction of initial capital investment of about $54 million, compared with Option 1A.

Under scenario 4, the timings and cost of some elements of Option 2A would be the same as Option 1A, ie, the increase in spot load under this scenario would mean that the line between Cultana and Yadnarie would need to be energised at 275 kV as soon as it was commissioned. However, the timings of other elements relating to energising the line between Yadnarie and Port Lincoln North at 275 kV would occur at a later date than under Option 1A.

Under scenario 4, a 3rd 275 kV single circuit (600 MVA, N-1) transmission line would be constructed between Cultana and Yadnarie, to meet the higher loads in this scenario.[26]

As with Option 1A, where additional anticipated spot loads request connection, new substations and transmission lines would be constructed. Specifically:

[26] This 3rd 275kV line would be operated at 275kV straightaway, since the double circuit 275kV line built initially would need to be operated at 275kV under this scenario.

- A third 200 MVA 275/132 kV Yadnarie transformer (under scenario 2 and 4).
- A new spot load located near Wudinna (ie, scenarios 3 and 4) would require: (i) a new double circuit, strung on one side only (600 MVA) 275 kV transmission line from the Yadnarie to Wudinna East Substations; and (ii) the construction of a new 275/132 kV substation at Wudinna East.

In addition Option 2A includes a 3rd 200 MVA 275/132 kV transformer at Cultana under scenarios 1 and 2.

As with Option 1A, all new 275 kV lines will be built in close proximity to existing lines, ie, they do not require running new, parallel corridors.

Option 2A also requires a number of reactive support elements to maintain voltage levels along the network. These elements are comprised of different capacitor banks throughout the peninsula depending on the scenario as well as a -50 + 50 MVAr SVC at Yadnarie under scenario 1 and a -100 + 100 MVAr SVC at Yadnarie under scenarios 2-4.

This option has the same layout as shown in Figure 5-1 above.

The timings and cost of each of the network elements of the Option 2A investment strategy under the four load scenarios is summarised in Table 5-4 below. Annual operating costs for the network elements have been estimated at 2% of this capital cost, consistent with the Grid Australia RIT-T Handbook.

Table 5-4: Timing and costs of the network components of Option 2A under each load scenario

Technical Characteristics of Option 2A	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)
- Build a double circuit 275 kV Line between Cultana and Yadnarie with a line capacity of 600 MVA per circuit (single sulphur conductor)	2020/21	235	2015/16	235	2015/16	235	2015/16	235
- Cultana substation works to allow for 2 new 132 kV line exits, including relocating 6 existing line exits		8	2015/16	8		-		-
- Cultana substation works to allow for 2 new 275 kV line exits and 2 reactors		-	2023/24	15		15		15
- New 275/132 kV substation at Yadnarie		-	2023/24	78		78		78
- Construction of a 3rd single circuit (600 MVA, N-1) 275 kV transmission line between Cultana and Yadnarie	-	-	-	-	-	-	2016/17	199
- Construction of a new double circuit (600 MVA, N-1) 275 kV transmission line from the Yadnarie to Port Lincoln North Substations (approximately 90km)	2020/21	153	2015/16	153	2015/16	153	2015/16	153
- New double circuit (200 MVA, N-1) 132 kV transmission line from the Port Lincoln North to Port Lincoln Substations (approximately 40km)		51		51		51		51
- New 275/132 kV substation at Port Lincoln North	-	-	-	-	-	-	2017/18	54

Technical Characteristics of Option 2A	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)
- Construction of a new double circuit, strung on one side only (600 MVA) 275 kV transmission line from the Yadnarie to Wudinna East Substations (approximately 85km) - New 275/132 kV substation at Wudinna East	-	-	-	-	2015/16	121 45	2015/16	121 45
- A third 200 MVA 275/132 kV Cultana transformer	2020/21	10	2015/16	10	-	-	-	-
- A third 200 MVA 275/132 kV Yadnarie transformer	-	-	2026/27	10	-	-	2015/16	10
- 1x25 MVAr cap bank at Port Lincoln	2019/20 2030/31	4 4	2029/30	4	2016/17 2024/25	4 4	2028/29	4
- 1x50 MVAr cap bank at Port Lincoln	-	-	2015/16 (x2)	9	-	-	2015/16 2016/17	5 5
- 1x25 MVAr cap banks at Wudinna	2019/20	5	2015/16	5	-	-	-	-
- 4x50 MVAr cap banks at Wudinna	-	-	-	-	2015/16	15	2015/16	15
- 1x50 MVAr cap bank at Cultana	2018/19 2024/25	5 5	2015/16	5	-	-		
- 1x100 MVAr cap bank at Cultana	-	-	2015/16	5	2015/16	5	2015/16 (x2) 2017/18 2025/26	11 5 5
- SVC (-50 + 50 MVAr) at Yadnarie	2018/19	19	-	-	-	-		
- SVC (-100 + 100 MVAr) at Yadnarie	-	-	2015/16	20	2015/16	20	2015/16	20

Technical Characteristics of Option 2A	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)
- 1x100 MVAr cap bank at Yadnarie	-	-	-	-	-	-	2015/16 2016/17	5 5
- 1x50 MVAr cap bank at Yadnarie	-	-	-	-	2017/18	5	2015/16 2030/31	5 5
Total lines costs ($ 2011/12)		**$439**		**$439**		**$560**		**$759**
Total substations costs ($ 2011/12)		**$18**		**$121**		**$138**		**$202**
Total reactive power costs ($ 2011/12)		**$42**		**$48**		**$53**		**$90**
TOTAL ($ 2011/12)		**$499**		**$608**		**$751**		**$1,051**

5.5 Option 2B

Under this option a double circuit 275 kV transmission line (1,000 MVA, N-1) is constructed between Cultana and Yadnarie and 275 kV double circuit transmission line (600 MVA, N-1) from Yadnarie to Port Lincoln North, with both circuits initially energised to 132 kV for as long as possible.

As the additional anticipated loads request connection, new substations and transmission lines would be constructed (as for Options 1A and 1B) and one or more sections of the line would also be energised to 275 kV.

Table 5-5 below illustrates when each of the three primary sections of the Lower Eyre Peninsula transmission network are built and energised at either 132 kV (black) and/or 275 kV (red).

Table 5-5: Option 2B – Timing of 132 kV or 275 kV operation

Network section	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Cultana to Yadnarie	2020/21 -	2015/16 2024/25	- 2015/16	- 2015/16
Yadnarie to Port Lincoln North	2020/21 -	2015/16 -	2015/16 -	2015/16 2017/18
Yadnarie to Wudinna East	-	-	- 2015/16	- 2015/16

The timings and cost of the elements of the Option 2B investment strategy would differ under scenarios 1 and 2 from that proposed for Option 1B. Specifically:

- For scenario 1, there would be no need initially for the 275/132 kV substations either at Yadnarie or Port Lincoln North, resulting in a reduction of initial capital investment of about $132 million, compared with Option 1B.
- For scenarios 2 and 3, there would be no need for the 275/132 kV substation at Port Lincoln North, resulting in a reduction of initial capital investment of about $54 million, compared with Option 1B.

For scenario 4, the timings and cost of some elements of Option 2B would be the same as Option 1B, ie, the increase in spot load under this scenario would mean that the line between Cultana and Yadnarie would need to be energised at 275 kV as soon as it was commissioned. However, the timings of other elements relating to energising the line between Yadnarie and Port Lincoln North at 275 kV would occur at a later date than under Option 1B.

As with Option 1B, when the additional anticipated spot loads request connection, new substations and transmission lines would be constructed. Specifically:

- A third 200 MVA 275/132 kV Yadnarie transformer (under scenario 2 and 4).
- A new spot load located near Wudinna (ie, scenarios 3 and 4) would require: (i) a new double circuit, strung on one side only (600 MVA) 275 kV transmission line from the Yadnarie to Wudinna East Substations; and (ii) the construction of a new 275/132 kV substation at Wudinna East.

In addition Option 2B includes a 3rd 200 MVA 275/132 kV transformer at Cultana under scenarios 1 and 2.

As with the other 275 KV options, all new 275 kV lines will be built in close proximity to existing lines, ie, they do not require running new, parallel corridors.

Option 2B also requires a number of reactive support elements to maintain voltage levels along the network. These elements are comprised of different capacitor banks throughout the peninsula depending on the scenario as well as a -50 + 50 MVAr SVC at Yadnarie under scenarios 1 – 3 and a -100 + 100 MVAr SVC at Yadnarie under scenario 4.

This option has the same layout as shown in Figure 5-2 above.

The timings and cost of each of the elements of the Option 2B investment strategy under the four load scenarios is summarised in Table 5-6 below.

Table 5-6: Timing and costs of the network components of Option 2B under each load scenario

Technical Characteristics of Option 2B	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)
- Construction of a new double circuit, high capacity (1,000 MVA N-1), twin conductor 275 kV transmission line from the Cultana to Yadnarie Substations (approximately 140km)	2020/21	292	2015/16	292	2015/16	292	2015/16	292
- New 275/132 kV substation at Yadnarie	-	-	2024/25	78	2015/16	78	2015/16	78
- Construction of a 3rd single circuit (1,000 MVA, N-1) 275 kV transmission line between Cultana and Yadnarie	-	-	-	-	-	-	-	-
- Construction of a new double circuit (600 MVA, N-1) 275 kV transmission line from the Yadnarie to Port Lincoln North Substations (approximately 90km) - New double circuit (200 MVA, N-1) 132 kV transmission line from the Port Lincoln North to Port Lincoln Substations (approximately 40km)	2020/21	153 51	2015/16	153 51	2015/16	153 51	2015/16	153 51
- New 275/132 kV substation at Port Lincoln North	-	-	-	-	-	-	2017/18	54
- Construction of a new double circuit, strung on one side only (600 MVA) 275 kV transmission line from the Yadnarie to Wudinna East Substations (approximately 85km) - New 275/132 kV substation at Wudinna East	-	-	-	-	2015/16	121 45	2015/16	121 45
- A third 200 MVA 275/132 kV Cultana transformer	2020/21	10	2015/16	10	-	-	-	-

Technical Characteristics of Option 2B	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)
- A third 200 MVA 275/132 kV Yadnarie transformer	-	-	2027/28	10	-	-	2015/16	10
- 1x25 MVAr cap bank at Port Lincoln	2019/20 2030/31	4 4	2030/31	4	2016/17	4	2028/29	4
- 1x50 MVAr cap bank at Port Lincoln	-	-	2015/16 (x2)	9	-	-	2015/16 2017/18	5 5
- 1x25 MVAr cap banks at Wudinna	2019/20	5	2015/16	5	-	-	-	-
- 4x50 MVAr cap banks at Wudinna	-	-	-	-	2015/16	15	2015/16	15
- 1x25 MVAr cap bank at Cultana	2028/29	5	2018/19	5	-	-	-	-
- 1x50 MVAr cap bank at Cultana	2018/19	5	2015/16	5	-	-	-	-
- 1x100 MVAr cap bank at Cultana	-	-	2015/16	5	2015/16	5	2015/16 (x2) 2018/19 2027/28	11 5 5
- SVC (-50 + 50 MVAr) at Yadnarie	2019/20	19	2015/16	19	2015/16	19	-	-
- SVC (-100 + 100 MVAr) at Yadnarie	-	-	-	-	-	-	2015/16	20
- 1x100 MVAr cap bank at Yadnarie	-	-	-	-	-	-	2016/17	5
- 1x50 MVAr cap bank at Yadnarie	-	-	-	-	2017/18	5	2015/16	5
- 1x25 MVAr cap bank at Yadnarie	-	-	2019/20	5	-	-	-	-
Total lines costs ($ 2011/12)		**$496**		**$496**		**$617**		**$617**

Technical Characteristics of Option 2B	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)
Total substations costs ($ 2011/12)		**$10**		**$98**		**$123**		**$187**
Total reactive power costs ($ 2011/12)		**$42**		**$57**		**$48**		**$80**
TOTAL ($ 2011/12)		**$548**		**$651**		**$788**		**$884**

5.6 Demand response component under Options 1A, 1B, 2A and 2B

The technical study undertaken by SKM indicated that under scenario 1 (ie, where there is assumed to be no mining load connecting on the Lower Eyre Peninsula), Option 1A, 1B, 2A and 2B would need to be commissioned in 2017/18 in order to meet the ETC standard at Port Lincoln.

ElectraNet also engaged EnerNOC to assess the potential for using aggregated demand response (DR) as a non-network addition to these options, in order defer the network investment.

EnerNOC provided the following annual cost estimates for a 3 year DR program beginning in 2016/17.[27]

Table 5-7: EnerNOC DR 3 year program costs (2011/12$)

	2016/17	2017/18	2018/19	2019/20
Annual cost	$200,000	$270,000	$648,000	$1,026,000

These costs are significantly outweighed by the cost savings of deferring the significant investment associated with Options 1A, 1B, 2A and 2B by 3 years (ie, from 2017/18 to 2020/21). ElectraNet has therefore incorporated a DM component as part of these options, under scenario 1. Under the other scenarios, the assumed timing of new spot load means that the network augmentation would occur in 2015/16 in order to meet the spot load requirements, ie, ahead of the date at which is would be required in order to meet the ETC standard.

ElectraNet has coupled the costs estimated by EnerNOC with its own estimates of the administrative and operational costs likely to be associated with such a DR program. Specifically, ElectraNet has assumed an additional annual cost of $200,000 in 2016/17 and $100,000 in each of 2017/18, 2018/19 and 2019/20. Further, the DR requirement has been based on the assumption that the existing Port Lincoln generation support contract is extended at its current cost from its expiry at the end of 2018 to 2019/20.

5.7 Option 3

Option 3 has three primary components:

1. Rebuilding the existing 132 kV Cultana to Port Lincoln line.
2. Additional generators at Port Lincoln to maintain the N-1 reliability.
3. 'On-site' generators to serve mining loads under scenarios 2 to 4.

Each of these components is discussed below.

[27] EnerNOC provided ElectraNet with separate annual DR costs for both a 3 year and 5 year program, with the option of starting each a year earlier than the DR is actually required, ie, in 2016/17. For the purposes of this RIT-T, ElectraNet has used the costs of the 3 year program starting a year early to ensure all is in readiness by 2017/18.

5.7.1 Rebuilding the existing 132 kV Cultana to Port Lincoln line

Option 3 involves rebuilding the existing Cultana to Port Lincoln line as a high capacity 132 kV radial line. Specifically, a single 132 kV radial transmission line would be built on a new easement, followed by the decommissioning of the existing line.

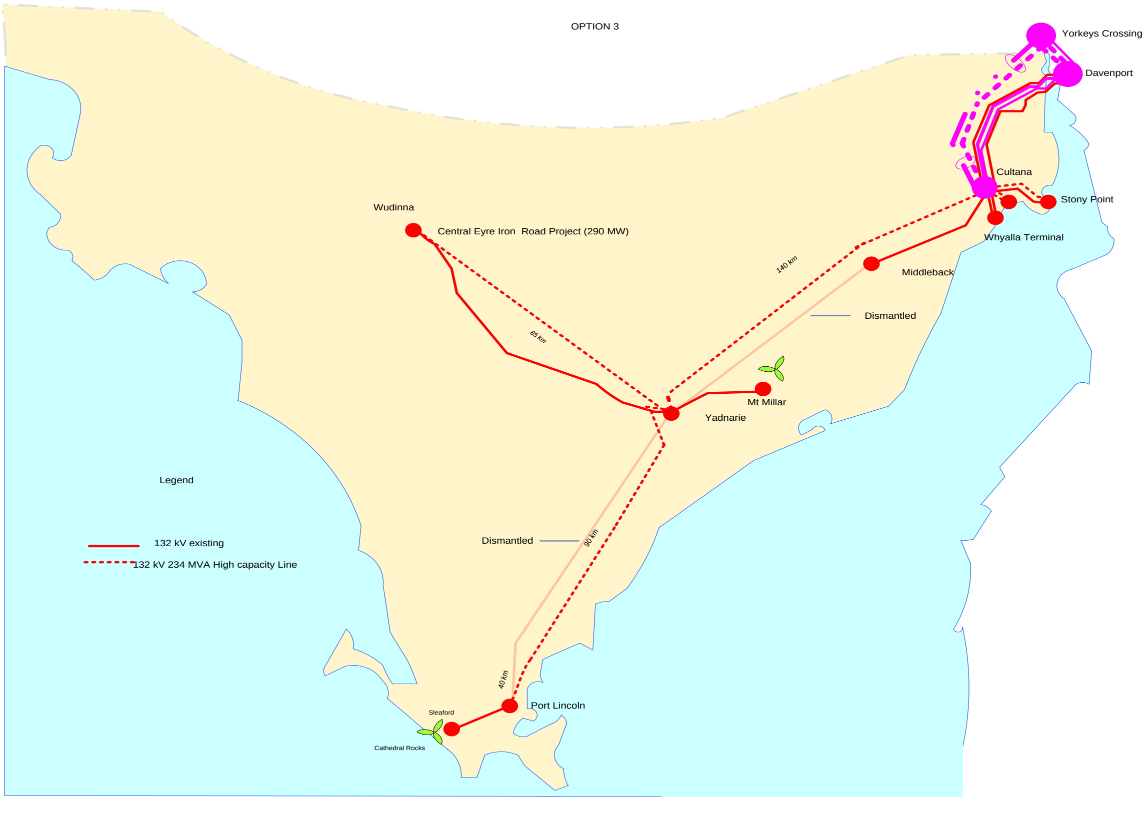
Under all scenarios this component of Option 3 is built in 2022/23. As ElectraNet noted in the PSCR, a 132 kV transmission line would not be adequate to provide the level of energy required when there is additional anticipated spot loads assumed and is therefore only built to address ageing asset concerns on the existing line, ie, in 2022/23.

Annual operating costs for the network components have been estimated at 2% of the network capital cost, consistent with the Grid Australia RIT-T Handbook.

Option 3 also requires a 25 MVAr cap bank at Wudinna in 2015/16 under all scenarios, in order to maintain voltage levels along the network.

The 132 kV component of Option 3 is depicted in Figure 5-3.

Figure 5-3: Option 3: 132 kV transmission solution plus 'on-site' generation



5.7.2 Additional generators at Port Lincoln to maintain the N-1 reliability

Since Option 3 continues to involve a single circuit 132 kV radial line, it also requires additional generators at Port Lincoln to maintain the N-1 reliability of ETC Category 3 on an on-going basis after 2017/18. Specifically:

- The existing generator support contract runs until the end of 2018. However, as outlined in section 3.6 above, IPR indicated in its submission that it would be willing to extend the existing contracted network support services at Port Lincoln post 2018. For the purposes of this RIT-T assessment ElectraNet has assumed this extension would occur at the same cost as those reflected in the current contract.
- Load growth at Port Lincoln would also require new generation support. SKM has estimated that by the end of 2032/33 92MW of generation support would be needed at Port Lincoln under scenario 1 and 110MW would be needed under scenarios 2, 3 and 4.[28] For the purposes of this RIT-T assessment ElectraNet has assumed that this new generation would be built as it is required, in addition to the continuation of the existing generation support.

The technical study undertaken by SKM estimated the costs of providing new generation support using a range of possible generating technologies and fuels. Specifically, SKM assessed the cost effectiveness of providing local power generation at Port Lincoln using three possible fuel alternatives – natural gas, distillate and low sulphur fuel oil (LSFO). The natural gas option includes substantial fixed cost elements (associated with constructing a new and the new lateral pipeline to the Eyre Peninsula) while the distillate and LSFO options are substantially variable cost options (other than the working capital cost and capital cost of fuel inventory/storage). Overall SKM concluded that the relatively low capacity factor of generation support at Port Lincoln (ie, an indicative capacity factor of less than 10%) makes distillate or LSFO the most suitable fuel.

SKM has provided both an annual standby charge as well as the annual usage charges (including fuel) for new high speed diesel generators using distillate fuel to provide Port Lincoln generation support under each scenario.[29]

5.7.3 On-site' generators to serve mining loads under scenarios 2 to 4

As ElectraNet noted in the PSCR, under all scenarios where there is additional anticipated spot loads assumed (i.e. scenarios 2 to 4), a 132 kV transmission line would not be adequate to provide the level of energy required. Therefore, in addition to rebuilding the existing Cultana to Port Lincoln line as a high capacity 132 kV radial line, Option 3 also includes the establishment of various 'on-site' generators to serve mining loads assumed to locate on the Eyre Peninsula under these scenarios. Under this option, these mines are assumed to operate their own on-site dedicated mining generation, rather than drawing their electricity needs from the grid.

As outlined in section 3.6, IPR indicated in its submission that it is willing to work with ElectraNet to provide brownfield and/or greenfield generation solutions at some or all of

[28] ElectraNet notes that the generation support requirements estimated by SKM take account of the N-1 ETC redundancy requirements at Port Lincoln. The higher requirement in scenarios 2, 3 and 4 reflects the higher growth rate at Port Lincoln assumed in those scenarios.

[29] SKM's costs include assumed carbon costs consistent with the core Federal Treasury forecasts.

Port Lincoln, Yadnarie and Wudinna, in order to meet the medium to long-term spot load requirements.

Similar to the costs of new generation support at Port Lincoln, SKM have assessed the cost effectiveness of providing on-site mining power generation using three possible fuel alternatives – natural gas, distillate and LSFO. SKM concluded that for the mining loads that have an indicated capacity factors of more than 30% (and are100 MW or more capacity) it would be reasonable to expect natural gas to be the fuel adopted. For smaller loads SKM concluded that the scale economies on the gas pipeline fall and the distillate option would become the selected fuel.

SKM has provided both an annual standby charge as well as the annual usage charges (including fuel) for the cost of on-site mining generation under each scenario.[30] To derive these cost estimates, SKM have made different assumptions regarding the particular generating technology depending on the size of the mining load serviced. Specifically, for the 30 MW Port Spencer mining load SKM has assumed that high speed diesel generators using distillate fuel would be employed, whereas for the larger mining sites, CCGT units using natural gas would be used.

The timings and cost of each of the network elements of the Option 3 investment strategy under the four load scenarios is summarised in Table 5-8 below. The timings and cost of each of the non-network elements of the Option 3 investment strategy under the four load scenarios is summarised in the following table, Table 5-9.

[30] ElectraNet notes that SKM's costs include assumed carbon costs consistent with the core Federal Treasury forecasts.

Table 5-8: Timing and costs of the network components of Option 3 under each load scenario

Technical Characteristics of Option 3	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)
- Single circuit 234 MVA 132 kV line from Cultana to Yadnarie	2022/23	100	2022/23	100	2022/23	100	2022/23	100
- Single Circuit 234 MVA 132 kV lines from Yadnarie to Port Lincoln	2022/23	90	2022/23	90	2022/23	90	2022/23	90
- 1x25 MVAr cap bank at Wudinna	2015/16	$5	2015/16	$5	2015/16	$5	2015/16	$5
Total lines costs ($ 2011/12)		**$190**		**$190**		**$190**		**$190**
Total substations costs ($ 2011/12)		**-**		**-**		**-**		**-**
Total reactive power costs ($ 2011/12)		**$5**		**$5**		**$5**		**$5**
TOTAL ($ 2011/12)		**$195**		**$195**		**$195**		**$195**

Table 5-9: Timing and costs of the non-network components of Option 3 under each load scenario

Technical Characteristics of Option 3	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)	Estimated year of commissioning	Estimated cost ($m)
- Extension of existing generation support at Port Lincoln to maintain ETC reliability	2018/19	105	2018/19	127	2018/19	127	2018/19	127
- New generation support at Port Lincoln to maintain ETC reliability	2017/18	154	2016/17	219	2016/17	193	2016/17	193
- Onsite generation required at Koppio*	-	-	2015/16	260	-	-	2015/16	316
- Onsite generation required at Carrow	-	-	2015/16	110	2015/16	186	2015/16	2,058
- Onsite generation required at Bungalow	-	-	-	-	-	-	2015/16	260
- Onsite generation required at Wudinna*	-	-	-	-	2015/16	2,817	2015/16	2,818
TOTAL ($ 2011/12)		**$259**		**$717**		**$3,324**		**$5,772**

Note: these costs include both the annual standby charge as well as the annual usage change (including fuel).

** Includes the other spot load assumed as part of the 50% of further potential spot loads, based on additional informal enquiries.*

6. Detailed Option Assessment

This section sets out the results of the NPV analysis for each of the credible options discussed in section 5.

The NER requires that the PADR set out a detailed description of the methodologies used in quantifying each class of material market benefit and cost, together with the results of the NPV analysis, and accompanying explanatory statement regarding the results. This section therefore discusses how each of the costs and material market benefits have been calculated, before presenting and discussing the results of that analysis across all of the credible options.

6.1 Quantification of Costs for Each Credible Option

This section provides a description of the costs of each of the five credible options assessed. Specifically, it provides an overview of how the costs have been estimated as well as providing a breakdown of the key cost drivers for each credible option.

6.1.1 Overview

Depending on the scenario, the costs of each option are comprised of all, or some, of the following components:

- Network costs;
- Generation costs; and
- DR costs.

The capital costs of the network component of each of the credible options have been developed by ElectraNet using internal cost estimates. These capital costs have been included as part of this RIT-T on the basis of the annual return on investment (ie, the 'WACC'[31]) plus the annual depreciation. The associated annual operating costs for these network components have been assumed to be 2% of the capital costs.

Annual generation costs have been estimated as part of the technical study undertaken by SKM. Specifically, SKM have estimated an annual standby charge[32] as well as annual usage charges (including fuel costs[33]) for the following generation costs:

- Extending the existing generation support at Port Lincoln once the current contract expires in December 2018 for Options 1A, 1B, 2A and 2B under scenario 1 (for 2 years) and for Option 3 under all scenarios (for the remainder of the assessment period);
- Introducing new generation support at Port Lincoln to maintain the ETC Standard under Option 3; and
- The cost of on-site mining generation for Option 3, under scenarios 2, 3 and 4.

31 The WACC adopted is consistent with the discount rate used in the NPV assessment.

32 The annual standby charge reflects the assumed rate of return (consistent with the discount rate used in the NPV analysis) and the period over which the investment will be recovered.

33 Fuel costs reflect an assumed carbon price, consistent with the core Treasury forecasts.

As discussed in section 5.6, EnerNOC has provided annual cost estimates for the application of a DR program beginning in 2016/17.[34] These costs have been incorporated in Options 1A, 1B, 2A and 2B under scenario 1, together with the estimated administration costs.

The total capital costs for each credible option in each reasonable scenario in NPV terms are set out in Table 6-1 below.

Table 6-1: Capital costs of each credible option (NPV $m, 2011/12$)

Option	Scenario 1	Scenario 2	Scenario 3	Scenario 4
1A	246.04	443.94	593.72	744.06
1B	262.44	469.61	622.80	640.16
2A	206.57	391.76	545.08	733.46
2B	224.33	423.96	573.23	629.21
3	127.57	277.44	1,267.70	2,187.31

Note: The annual generation standby charges have been included in the capital costs reported in this table, for comparability with the presentation of the network investment costs. In reality these charges would likely be in the form of an annual fixed operating charge to ElectraNet.

The total operating costs for each credible option in each reasonable scenario in NPV terms are set out in Table 6-2 below.

Table 6-2: Operating costs of each credible option (NPV $m, 2011/12$)

Option	Scenario 1	Scenario 2	Scenario 3	Scenario 4
1A	45.29	82.45	110.25	138.11
1B	48.28	87.26	115.68	118.83
2A	38.27	72.70	101.35	136.17
2B	41.50	78.73	106.62	116.83
3	19.45	1,225.14	2,295.39	4,423.62

Note: The annual generation standby charges have been included in the capital costs reported in Table 6.1, for comparability with the presentation of the network investment costs. In reality these charges would likely be in the form of an annual fixed operating charge to ElectraNet.

The *total* costs (ie, capital and operating costs) for each credible option in each reasonable scenario in NPV terms are set out in Table 6-3 below.

[34] Specifically, EnerNOC provided ElectraNet with separate annual DR costs for both a 3 year and 5 year program, with the option of starting each a year earlier than the DR is actually required, ie, in 2016/17. For the purposes of this RIT-T, ElectraNet has used the costs of the 3 year program starting a year early to ensure all is in readiness by 2017/18.

Table 6-3: Total costs of each credible option (NPV $m, 2011/12$)

Option	Scenario 1	Scenario 2	Scenario 3	Scenario 4
1A	$291.33	$526.39	$703.97	$882.17
1B	$310.72	$556.88	$738.47	$758.99
2A	$244.83	$464.46	$646.44	$869.62
2B	$265.83	$502.69	$679.85	$746.04
3	$147.01	$1,502.57	$3,563.09	$6,610.93

6.1.2 Options 1A, 1B, 2A and 2B

Figure 6-1 to Figure 6-4 below provide a breakdown of the different cost categories for Options 1A, 1B, 2A and 2B, under each reasonable scenario.

The costs of these options are comprised of the network component capex costs and the associated network operating costs. The only exception is under scenario 1, where there are also costs for the 3 year DR program at Port Lincoln and the extension of the existing generation support contract. However, as it clear from the figures, these costs do not form a significant proportion of the overall total.

Figure 6-1: Breakdown of cost categories - Option 1A

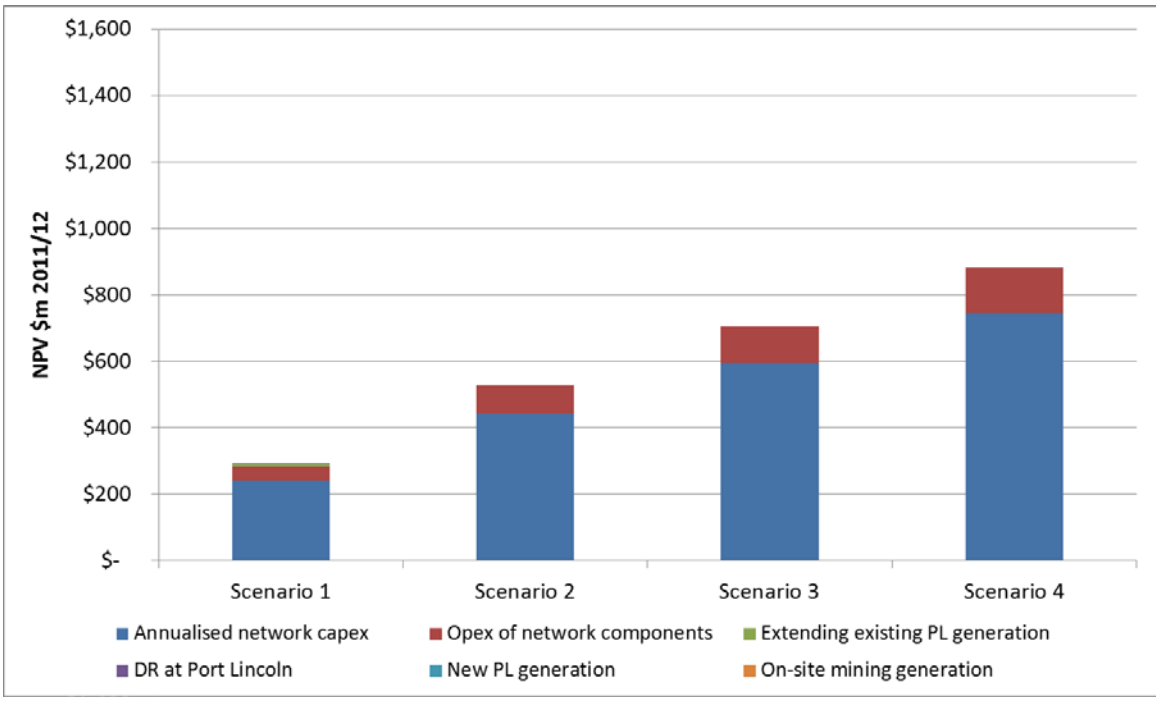


Figure 6-2: Breakdown of cost categories - Option 1B

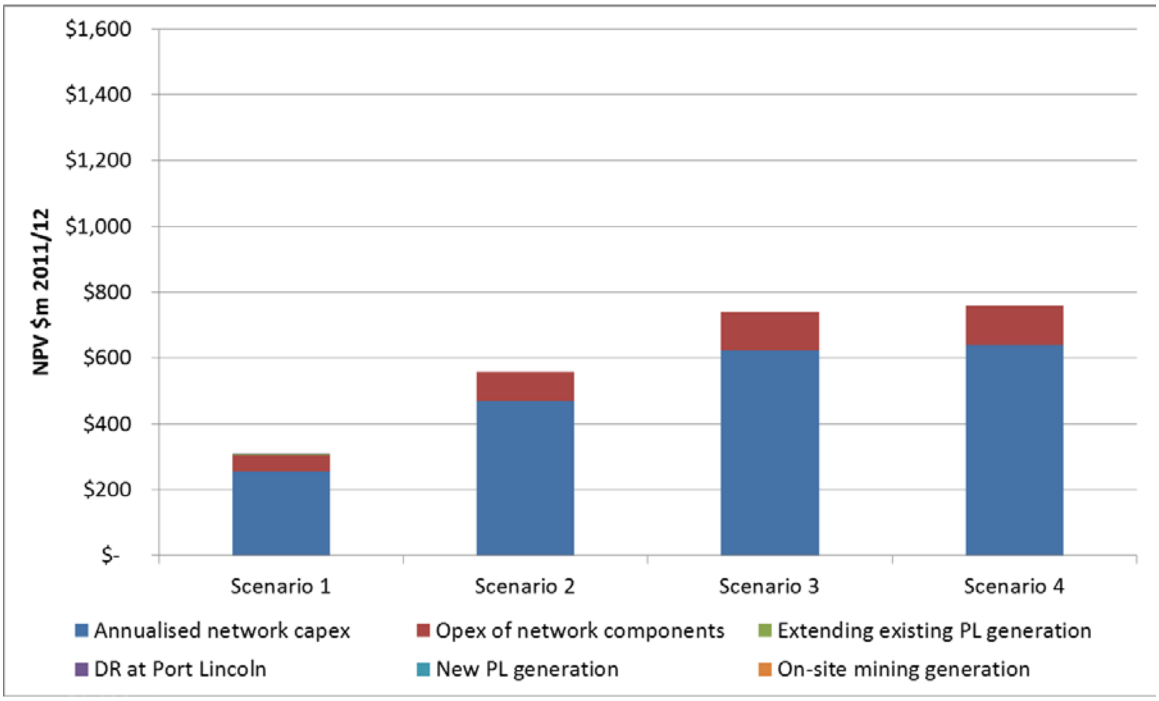


Figure 6-3: Breakdown of cost categories - Option 2A

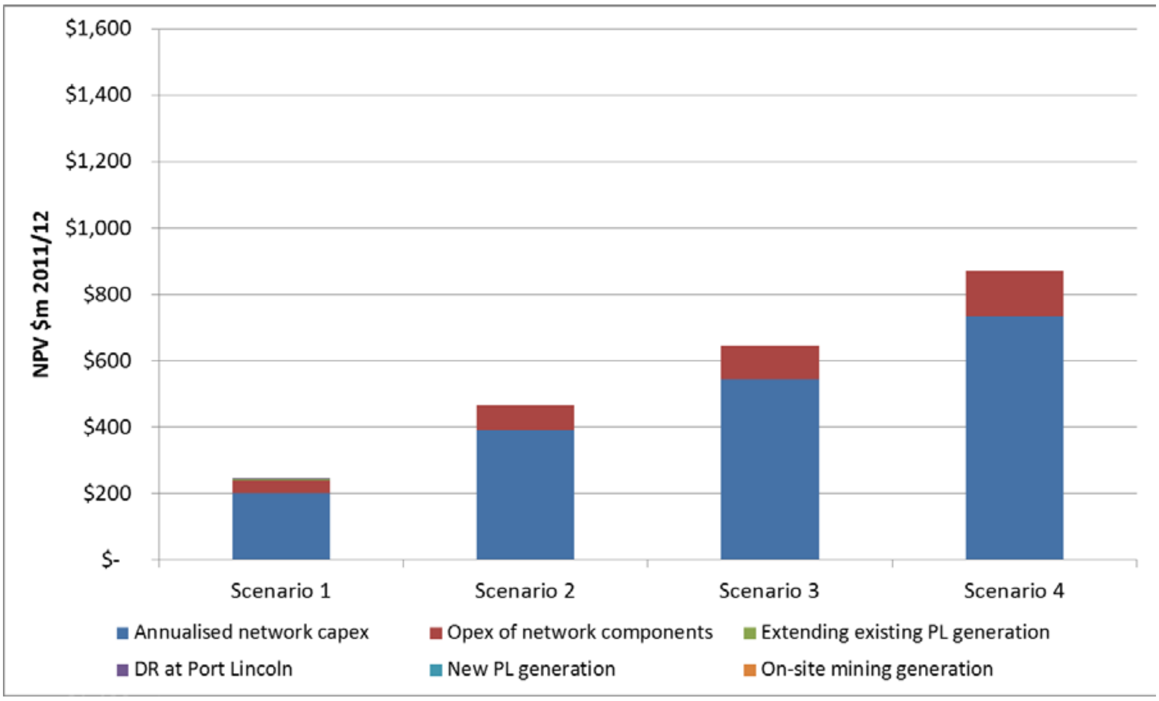
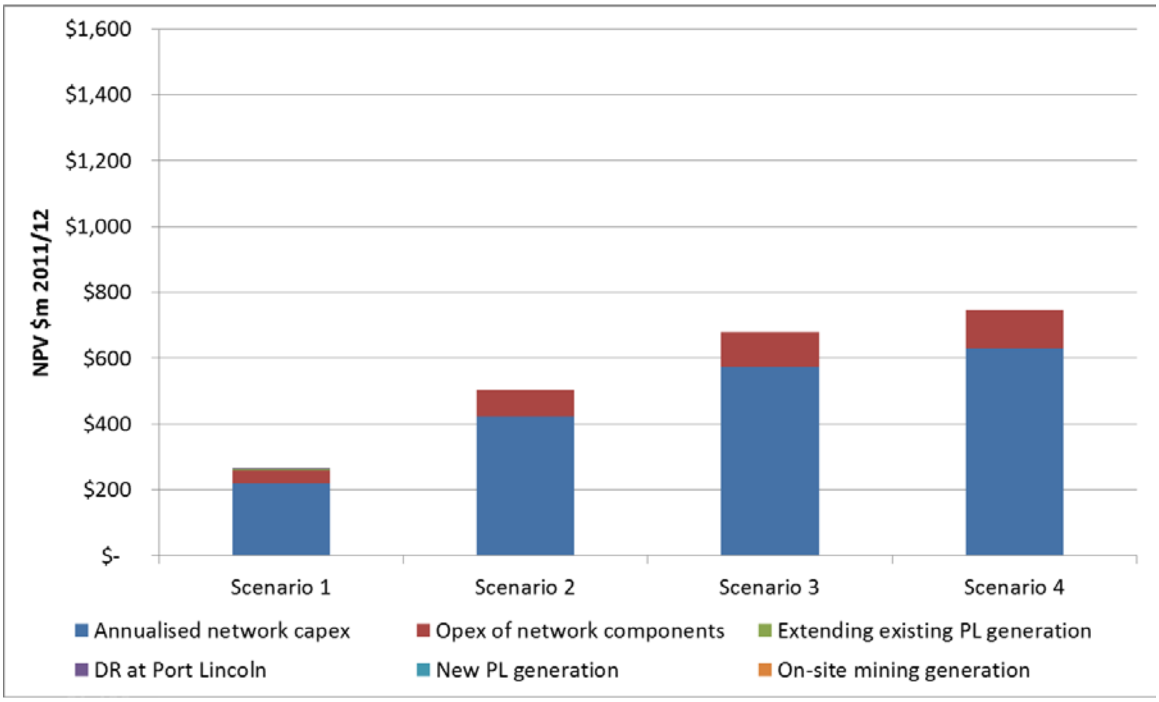


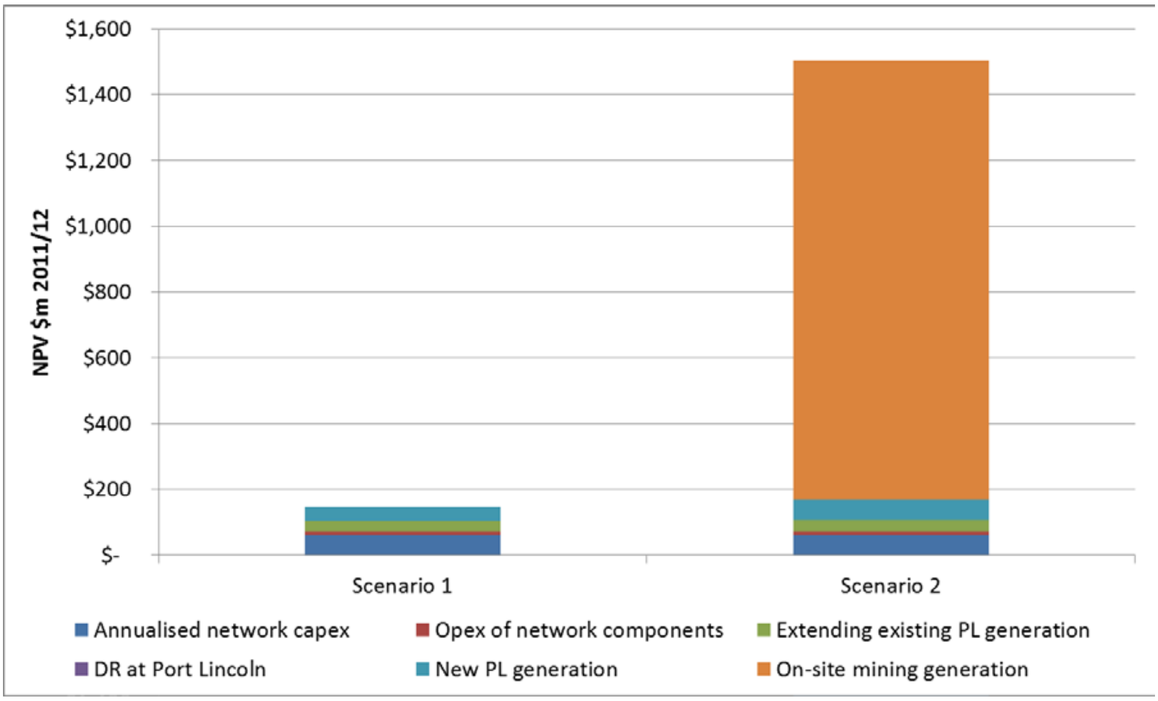
Figure 6-4: Breakdown of cost categories - Option 2B



6.1.3 Option 3

Figure 6-5 below shows the breakdown of cost components for Option 3 under scenarios 1 and 2. The figure shows clearly that the cost of providing on-site generation to meet mining load drives a substantial difference in the costs of Option 3 under these different scenarios. These on-site generation costs rise even further under scenarios 3 and 4, where more mining load is assumed to locate on the Lower Eyre Peninsula.

Figure 6-5: Cost categories of Option 3, under reasonable scenarios 1 and 2



6.2 Quantification of Classes of Material Market Benefits

6.2.1 Changes in network losses

The annual MWh of network losses for all credible options have been estimated by SKM, for each year of the assessment period.

These estimates have then been used to calculate the difference in losses (MWh) between the base case and with each option in place. ElectraNet has assumed an indicative base case level of MWh losses for each scenario by extrapolating the implied annual growth in losses estimated by SKM in the period prior to 2017/18.[35] ElectraNet considers that a more detailed estimation of the losses under the base case would represent a disproportionate level of analysis, given the limited magnitude of the market benefit associated with losses, and since the precise numbers assumed for the base case do not affect the outcome of the RIT-T.[36]

ElectraNet has applied an annual value of losses reflecting the average SRMC of generation in South Australia obtained from internal market modelling undertaken by ElectraNet,[37] to the annual MWh difference in losses, in order to estimate the value of the change in losses for each option under each scenario. The average SRMC value used is provided in Appendix D.

6.2.2 Changes in involuntary load shedding

The RIT-T only allows for the incremental improvement in unserved energy (USE) over and above the required reliability standard to be included in the RIT-T, where the investment is classed as a reliability corrective action.[38] The applicable reliability standard is the South Australian ETC reliability standards in the case of the Lower Eyre Peninsula reinforcement.

SKM has calculated the expected annual level of USE (in MWh) under each of the credible options, for each year of the assessment period.

ElectraNet has made the assumption that the level of USE (in MWh) required to meet the ETC is represented by the USE estimated by SKM for Option 3 (ie, the 132 kV option with on-site mining generation).[39]

The resulting MWh improvement in USE over and above the minimum standard has then been calculated for each option, and valued at AEMO's estimate of the value of

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35 Specifically, ElectraNet has extrapolated for all years post 2017/18 using the implied annual growth rate over the period 2014/15 and 2017/18.

36 The level of losses assumed in the base case does not affect the ranking of the options under the RIT-T as the benefit from changes in losses for all options are all measured *relative* to the base case.

37 The SRMC estimates include assumed carbon costs consistent with the core Federal Treasury forecasts.

38 AER, *Regulatory investment test for transmission*, June 2010, clause (9).

39 ElectraNet notes that this proxy is not perfect (for example, in some years the USE under Option 3 is less than Options 1A, 1B, 2A and 2B). However, ElectraNet notes that the assumed level of USE required to meet the ETC standard does not affect the ranking of the options under the RIT-T as all options are simply measured *relative* to this level.

customer reliability (VCR) for South Australia, ie, $44,300/MWh, adjusted to $2011/12 dollars.[40]

6.2.3 Changes in costs for parties, other than for ElectraNet involuntary load shedding

Changes in costs to other parties reflects the differences in the value of generation investment between the base case 'state of the world' and the 'state of the world' resulting from the implementation of each of the credible options. The 'state of the world' is the pattern of generation investment and dispatch in the NEM.

Differences in generation investment can relate to the type, timing and quantity of generation investment between the base case (in which no investment is made by ElectraNet) and each credible option.

As discussed in section 4.1.3, where the network option would facilitate an increase in the investment of wind generation in the Eyre Peninsula (ie, Options 1A, 1B, 2A and 2B) the main impact of the credible options on the pattern of generation investment is expected to be in relation to the development of wind generation. Specifically, for these options, ElectraNet has assumed:

- No change in the current constraint on exports of wind generation from South Australia;
- New wind generation on the Eyre Peninsula rises 'in-step' with the mining spot load assumed to locate on the Eyre Peninsula, in order to supply that spot load. As a consequence, there will only be additional wind generation under those scenarios where there is assumed spot load development (ie, scenarios 2, 3 and 4); and
- New wind generation on the Eyre Peninsula will displace generation investment in a lower quality wind resource elsewhere in the NEM (assumed to be NSW) that would have otherwise occurred to meet the LRET target.

As a consequence, this category of market benefit is expected to arise both in South Australia, and also in other regions across the NEM.

For each scenario, the amount of additional wind generation (in MW) that would be able to locate on the Eyre Peninsula has been estimated under each option in each scenario, according to the quantity of mining load also assumed to locate on the Eyre Peninsula. Using an assumed average annual capacity factor of 38.3% for wind locating on the Eyre Peninsula (consistent with AEMO's 2011 National Transmission Network Development Plan (NTNDP) assumptions),[41] the annual output of this additional wind generation has then been estimated for a particular scenario.

For each scenario, ElectraNet has assumed that, if no upgrade to the Lower Eyre Peninsula occurs (ie, under the base case), this annual generation (in MWh) would have

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[40] AEMO's estimate of the VCR for South Australia is in June 2009 dollars. This estimate has been converted into December 2011 dollars (ie, the middle of the 2011/12 year) using percentage change in the CPI (All Groups) for Australia between these two dates.

[41] As part of the 2011 NTNDP assumptions, AEMO included four 'tranches' of wind locations throughout the NEM and Tranche 1 is the one with the highest assumed capacity factor for each region. ElectraNet's assumption regarding the capacity factor of wind farms on the Eyre Peninsula is consistent with wind farms locating in a 'Tranche 1' location. ElectraNet has tested this assumption and has found that alternative assumptions do not affect the outcome of the RIT-T.

been instead generated by new wind farms located in NSW, ie, consistent with the assumption that the LRET target is met. Using an assumed average annual capacity factor of 33.6% for wind farms locating in NSW from AEMO's 2011 NTNDP assumptions,[42] the size (in MW) of wind generation that would have had to be constructed in NSW in order to generate the same amount of output as the additional wind farms able to locate on the Eyre Peninsula has been estimated, under each scenario.

For each option under each scenario, the changes in costs for parties other than ElectraNet has been calculated as the difference in the costs of establishing and operating additional wind generation in the Eyre Peninsula and the costs of establishing and operating a greater amount of wind generation (in MW) to produce an equivalent annual output (in MWh) in NSW. The costs associated with building and operating wind farms have come from Worley Parsons' 2011 report to AEMO covering the cost of construction for new generation technology.[43] Specifically, ElectraNet has assumed:

- capital costs for each year of the assessment period consistent with Worley Parsons 'central' scenario (scenario 3);
- annual fixed operating and maintenance costs of $40,000/MW/year for 2012;[44] and
- variable operating and maintenance costs of $12/MWh for 2012.[45]

Worley Parsons assumes that both the fixed and variable operating and maintenance costs escalate at 150 per cent of CPI inflation each year.[46] For the purposes of this RIT-T, ElectraNet has therefore escalated these assumed fixed and variable operating maintenance costs on the basis of the midpoint of the Reserve Bank's CPI inflation forecasts (June on June) in the latest Statement on Monetary Policy until June 2014[47] and a value of 2.60% per annum from then onward consistent with the AER's latest regulatory determination (for Powerlink).[48]

6.2.4 Changes in fuel consumption (arising through different patterns of generation dispatch)

A further category of market benefit relevant for this RIT-T assessment is the impact of each credible option on the overall fuel costs associated with generation in the NEM.

For this RIT-T the impact on fuel costs is expected to come from:

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42 Specifically, ElectraNet has taken the average capacity factor of the four subregions in NSW that are included in the AEMO NTNDP assumptions given it is not possible to infer whereabouts in NSW these wind farms would choose to locate. Further, as with the Eyre Peninsula, ElectraNet's assumption regarding these capacity factors is consistent with wind farms locating in a 'Tranche 1' location in NSW. ElectraNet has tested this assumption and has found that alternative assumptions do not affect the outcome of the RIT-T.

43 Worley Parsons, (2012), *Cost of Construction New Generation Technology*, 10 February 2012.

44 Op cit, p. 62.

45 Ibid.

46 Op cit, p. 14.

47 Reserve Bank of Australia, (2012), *Statement on Monetary Policy*, May 2012, p. 67.

48 AER, (2012), *Powerlink Transmission Determination 2012–13 to 2016–17*, Final Decision, p. 33

- The increase in fuel costs associated with meeting the new spot load on the Eyre Peninsula, at times when the assumed additional wind generation is unavailable;[49]
- The increase in fuel costs associated with higher non-wind output in NSW, as a consequence of wind generation locating in the Eyre Peninsula instead of NSW; and
- The avoided costs of operating the existing network support generators at Port Lincoln.

As a consequence, this category of market benefit is expected to arise both in South Australia, and also in other regions across the NEM.

For Options 1A&B and 2A&B under scenarios 2, 3 and 4 where wind generation is assumed to locate on the Eyre Peninsula, ElectraNet has estimated the *increase* in the fuel costs of the marginal generator in South Australia to compensate for when the wind farms are not able to generate. This increase in fuel costs has been estimated assuming that Torrens Island A is the marginal generator in South Australia. Specifically, it has been assumed that Torrens Island A increases its output to compensate for when wind farms assumed to locate on the Eyre Peninsula are not operating at 100 per cent capacity. An annual short-run marginal cost (SRMC) for Torrens Island A has been obtained from internal market modelling undertaken by ElectraNet.

Further, under Options 1A&B and 2A&B under scenarios 2, 3 and 4, ElectraNet has also estimated the *increase* in the fuel costs of the marginal generator in NSW to compensate for the output of wind generators that are assumed to locate there under the base case. This increase in fuel costs has been estimated assuming that Vales Point is the marginal generator in NSW.[50] Specifically, it has been assumed that Vales Point increases its output to compensate for when wind farms assumed to locate in NSW under the base case are not operating at 100 per cent capacity. An annual SRMC for Vales Point has been obtained from internal market modelling undertaken by ElectraNet.

As discussed in section 2.1.1, supply to Port Lincoln is currently supported by a network support agreement that allows ElectraNet to call upon the services of three distillate fired gas turbines generators when needed. The existing contract includes both a fixed ‘availability’ charge as well as a variable ‘usage’ or ‘running’ charge and expires in December 2018. For options 1A&B and 2A&B under scenarios 2, 3 and 4, where network options are assumed to be built prior to December 2018, these generators are no longer required to provide network support at Port Lincoln once the option is operational and hence the variable component of the existing contract is avoided, although the fixed component is not. The avoided variable costs under the current network support contract have been incorporated into this RIT-T as a market benefit.

[49] The impact on wind generator operating costs has already been taken into account in the calculation of the impact on other parties, discussed above.

[50] ElectraNet notes that its internal modeling also indicated that Bayswater may be the marginal generator in NSW later on (specifically post-2033/34). For the purposes of this RIT-T ElectraNet has assumed the marginal generator is Vales Point for the entire period as it is estimated to have a similar SRMC to Bayswater (between $2-6/MWh different over the period) and discounting at the later end of the period would render any such a difference in SRMC immaterial.

6.3 NPV Results

This section summarises the results of the NPV analysis, including the sensitivity analysis undertaken.

Appendix G sets out the full NPV results for each of the credible options, under each of the four scenarios. The full NPV analysis shows separately the costs for each option, and each class of material market benefits.

6.3.1 Gross market benefits

Table 6-4 summarises the gross market benefit, in NPV terms, for each of the five credible options. The gross market benefit is the sum of each of the individual categories of material market benefit (both positive and negative), as quantified on the basis of the approach set out in the preceding section.

The gross market benefit of each option has been calculated for each of the four reasonable scenarios.

The overall gross market benefit included in the RIT-T represents the weighted outcome of the gross market benefit in each reasonable scenario. This is discussed further in section 6.3.2.

Table 6-4: Gross Market Benefit for Each Credible Option (NPV $m, 2011/12)

		Scenario 1	Scenario 2	Scenario 3	Scenario 4
Scenario weights		30%	30%	30%	10%
Option 1A	275 kV double-circuit (600 MVA) transmission line solution from Cultana to Port Lincoln North, with a 3rd 600 MVA line from Cultana to Yadnarie when needed	$23	-$318	-$1,303	-$2,279
Option 1B	275 kV double-circuit (1,000 MVA) transmission line solution from Cultana to Port Lincoln North	$23	-$318	-$1,299	-$2,276
Option 2A*	275 kV double-circuit (600 MVA) transmission line solution initially operated at 132 kV, with a 3rd 600 MVA line from Cultana to Yadnarie when needed	$24	-$315	-$1,303	-$2,279
Option 2B*	275 kV double-circuit (1,000 MVA) transmission line solution initially operated at 132 kV	$24	-$315	-$1,299	-$2,276
Option 3	Rebuild Cultana to Port Lincoln as a high capacity 132 kV radial line plus on-going generation support at Port Lincoln and on-site generation to supply mining load	$5	$6	$6	$6

**All circuits built to 275 kV to be operated at 132 kV for as long as possible.*

Figure 6-6 to Figure 6-9 below illustrate the relative magnitude of each of the categories of market benefit estimated under the RIT-T, as quantified on the basis of the approach set out in the preceding section. The figures also show how these benefits vary across the four different scenarios.

In summary:

- There are minor differences in changes to network losses and involuntary load shedding across the options.[51] These represent positive market benefits or market costs, depending on the scenario; [52]
- Fuel cost benefits and costs to other parties are the main component of market benefits, for scenarios 2, 3 and 4.
- Differences in generation investment ('costs to other parties') represents a positive market benefit.
- Differences in fuel costs represent an overall market cost, reflecting the additional generation costs required to meet the higher spot load in scenarios 2, 3 and 4.
- The fuel cost benefits and the costs to other parties are identical for Options 1A, 1B, 2A and 2B under scenarios 2, 3 and 4. These benefits are driven by the amount of wind generation assumed to connect in the Eyre Peninsula, which is the same under each of these options, for a given scenario.

The figures also show that the gross market benefits estimated for each option are outweighed by the costs of each option. This reflects the fact that this is a reliability-driven investment, and the improvement in reliability that is able to be quantified under the RIT-T only relates to any differences over and above the minimum reliability standard.

[51] ElectraNet notes that there are no market benefits associated with reductions to involuntary load shedding for Option 3 given it has been assumed the level of USE under Option 3 is the same as that required to meet the ETC Standard (as discussed in section 6.2.2 above).

[52] In some scenarios the USE benefit is shown as negative for some options. This indicates that the USE under Option 3 is not a perfect proxy for the USE associated with meeting the ETC standard. However this does not affect the outcome of the RIT-T.

Figure 6-6: Gross market benefits and costs, scenario 1 (NPV $m, 2011/12)

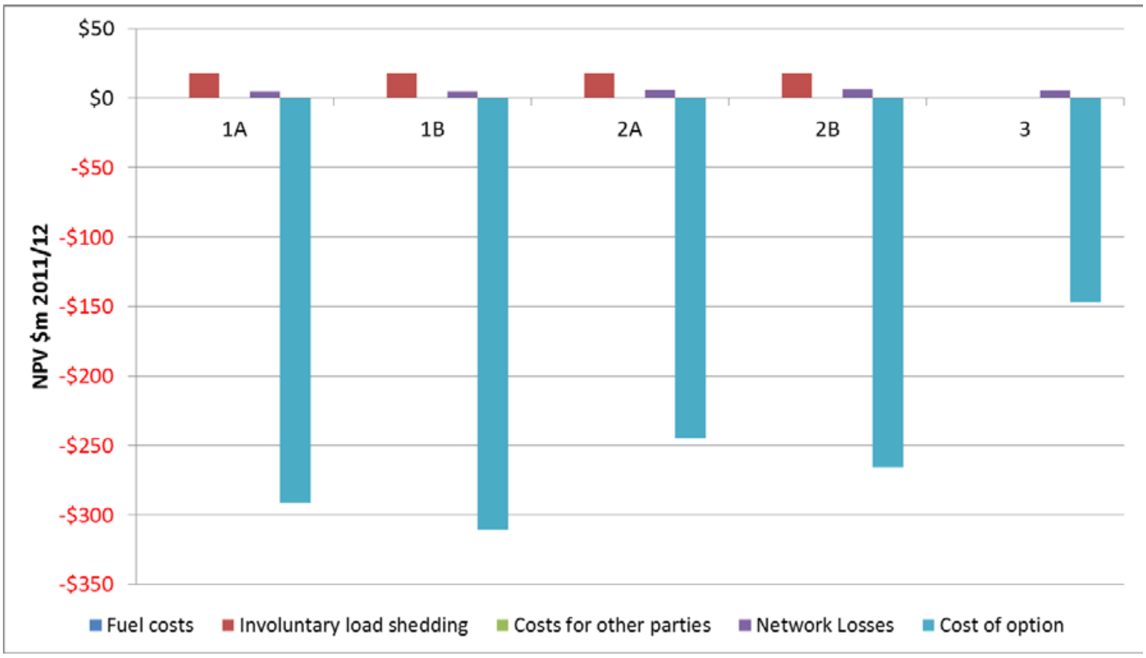


Figure 6-7: Gross market benefits and costs, scenario 2 (NPV $m, 2011/12)

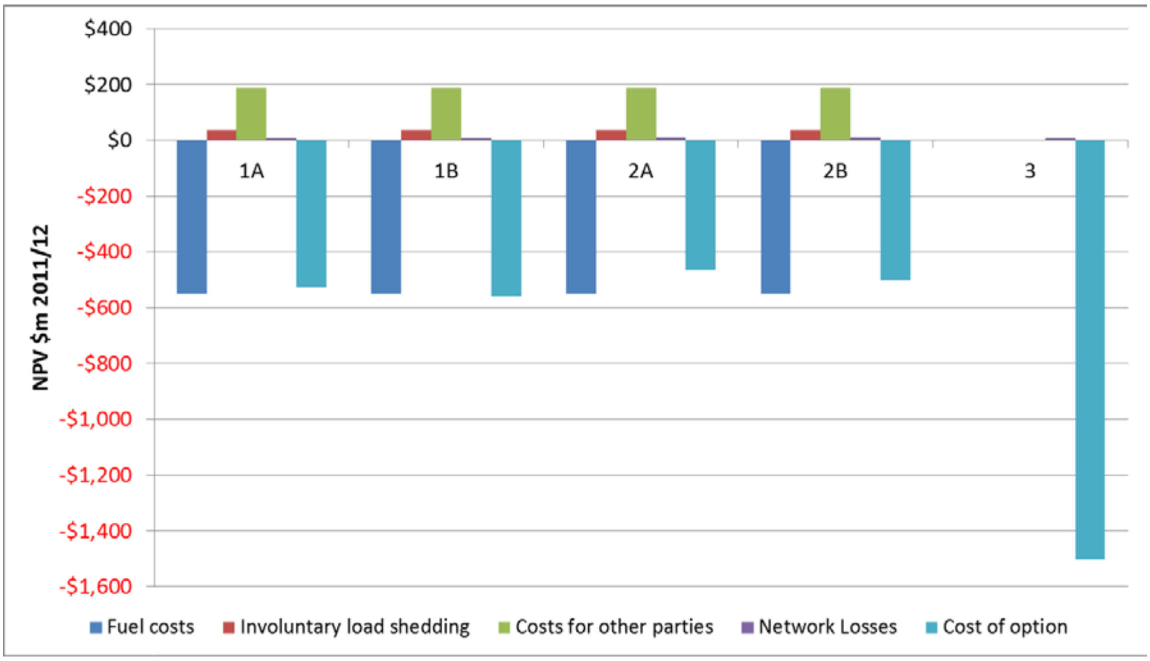


Figure 6-8: Gross market benefits and costs, scenario 3 (NPV $m, 2011/12)

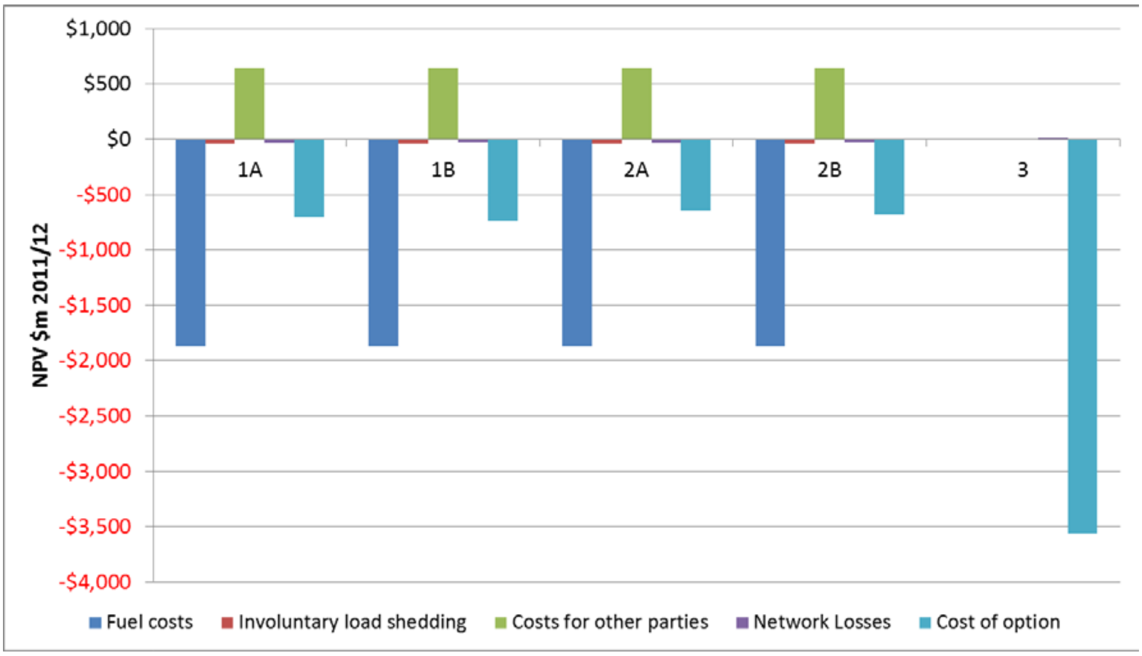
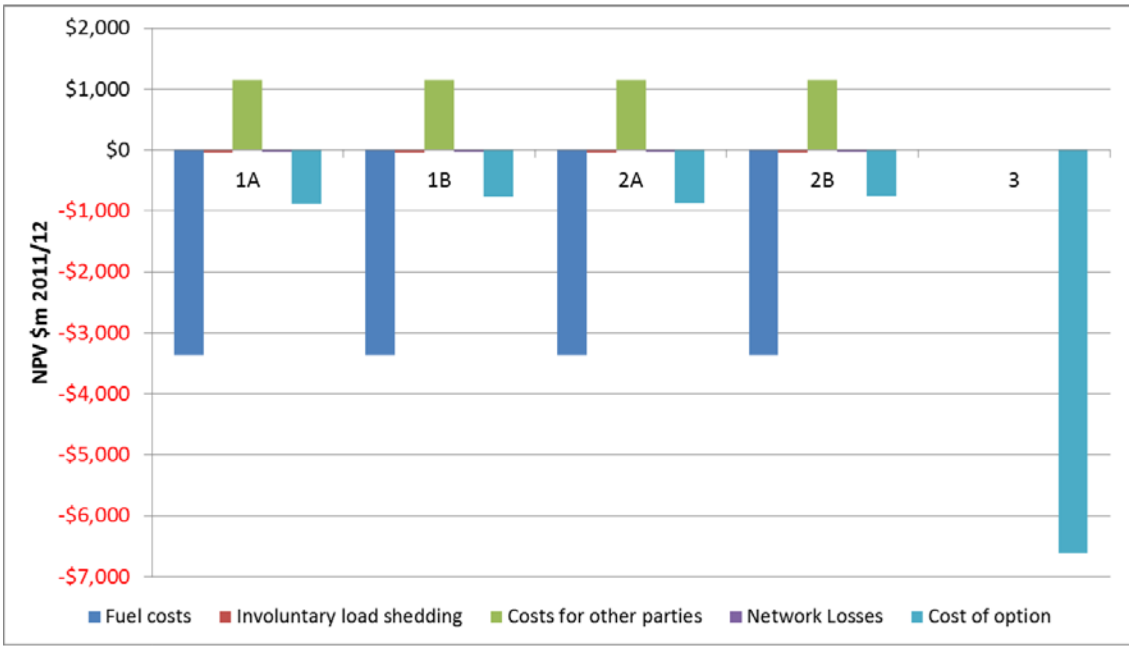


Figure 6-9: Gross market benefits and costs, scenario 4 (NPV $m, 2011/12)



6.3.2 Net market benefits

Table 6-5 summarises the net market benefit in NPV terms for each credible option under each scenario. The net market benefit is the gross market benefit (as set out in Table 6-4 minus the costs of each option, all in present value terms.

The table also shows the corresponding ranking of each option, for each scenario, with the options ranked from 1 to 5 in order of descending net market benefit.

As noted earlier, the RIT-T assessment is a weighted outcome across all reasonable scenarios. Table 6-5 therefore also presents the weighted net market benefit, and the ranking of the options under the RIT-T under this weighted outcome.

The table shows that the relative ranking of the five options differs across the four scenarios. In summary:

- Option 3 is ranked 1st under scenario 1 but ranked last (with a substantially higher overall net market cost) in all other scenarios.
- Option 2A is ranked 2nd under scenario 1, 1st under scenarios 2 and 3 and 3rd under scenario 4.
- Option 2B is ranked 3rd under scenario 1, 2nd under scenarios 2 and 3 and 1st under scenario 4.
- Options 2A and 2B are ranked ahead of Options 1A and 1B under the lower demand scenarios (ie, all scenarios except scenario 4), reflecting the lower cost of those options resulting from their flexibility to defer substation investments in scenarios where there is lower spot load.

The difference in net market benefit between options is driven by differences in the relative costs of the options. As discussed in the previous section, the values of the key market benefit categories are the same across all of the options (with the exception of Option 3), whilst the costs of the options vary. For Option 3, the difference in its total costs between scenario 1 (no spot load) and the other scenarios reflects the additional on-site generation costs which would be required to meet the new mining spot load. The increase in the costs of on-site generation for Option 3 in these scenarios is greater than the increase in fuel costs for the larger network augmentations, indicating that the fuel costs associated with new mining load can be met at a lower cost using NEM-connected generation, compared with installing on-site generation.

Overall Table 6-5 shows that Option 2A (ie, the 275 kV double-circuit 600 MVA line from Cultana to Port Lincoln North, initially operated at 132 kV, with a 3rd 275 kV 600 MVA line between Cultana and Yadnarie added when needed) is ranked 1st under the RIT-T, on the basis of the weighted average of the net market benefits across all scenarios. Option 2B (which is the equivalent option, but with a 1,000 MVA rating) is ranked 2nd. However, the difference in terms of the net market benefit of these two options is only $14m, or 1.2%.

ElectraNet has undertaken a range of sensitivity analysis to test the robustness of the RIT-T outcomes to both differences in the weightings adopted across the scenarios and also in relation to key input assumptions. These are discussed in section 6.3.3 below.

Table 6-5: Net Market Benefit and Ranking of Each Credible Option, Under Each Scenario (NPV $m, 2011/12)

		Scenario 1: 30%		Scenario 2: 30%		Scenario 3: 30%		Scenario 4: 10%		Weighted Average	
Option	**Description**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**	**Net Market Benefit**	**Ranking**
1A	275 kV double-circuit (600 MVA) transmission line solution from Cultana to Port Lincoln North, with a 3rd 600 MVA line from Cultana to Yadnarie when needed	-$269	4	-$844	3	-$2,007	3	-$3,161	4	**-$1,252**	3
1B	275 kV double-circuit (1,000 MVA) transmission line solution from Cultana to Port Lincoln North	-$288	5	-$874	4	-$2,037	4	-$3,035	2	**-$1,263**	4
2A*	275 kV double-circuit (600 MVA) transmission line solution initially operated at 132 kV, with a 3rd 600 MVA line from Cultana to Yadnarie when needed	-$221	2	-$780	1	-$1,949	1	-$3,148	3	**-$1,200**	1
2B*	275 kV double-circuit (1,000 MVA) transmission line solution initially operated at 132 kV	-$242	3	-$818	2	-$1,979	2	-$3,022	1	**-$1,214**	2
3	Rebuild Cultana to Port Lincoln as a high capacity 132 kV radial line plus on-going generation support at Port Lincoln and on-site generation to supply mining load	-$142	1	-$1,496	5	-$3,557	5	-$6,605	5	**-$2,219**	5

**All circuits built to 275 kV to be operated at 132 kV for as long as possible.*

6.3.3 Robustness to different scenario weightings

ElectraNet has tested the robustness of the ranking of options under the RIT-T to the weightings applied to each reasonable scenario.

Specifically, ElectraNet has investigated:

- The weighting that would need to be applied to scenario 1 (no spot load) in order for Option 3 to be the preferred option, under the weighted average of all scenarios, rather than Option 2A; and
- The weighting that would need to be applied to scenario 4 (high spot load) in order for Option 2B (ie, 1,000 MVA ratings) to be the preferred option, under the weighted average of all scenarios, rather than Option 2A (ie, 600 MVA ratings).

The results of this analysis indicate that at least a 97% weighting[53] would need to be applied to scenario 1 (assuming the remaining 3% weighting being applied equally to scenarios 2, 3 and 4) in order for Option 3 to be the preferred option under the RIT-T.

Similarly, at least a 19% weighting would need to be applied to scenario 4 (assuming the remaining 81% weighting being applied equally to scenarios 1, 2 and 3) in order for the higher 1,000 MVA rated Option 2B to be identified as the preferred option under the RIT-T.

6.3.4 Sensitivity analysis

Sensitivity analysis has been undertaken to test the robustness of the RIT-T assessment.

Given the importance of the relative costs of the different options in driving the RIT-T results, the sensitivity analysis has focused on the impact on the results of differences in cost assumptions. Specifically, the following four sensitivity tests have been undertaken:

- A 25% reduction in the costs estimated for the lines components of each of the credible options.
- A 25% reduction in the assumed costs of on-site generation required to meet spot loads.
- Replacement of only 25% of the existing 132 kV line under Option 3.
- A 25% increase in the assumed costs of the third 275 kV (600 MVA) line between Cultana and Yadnarie.

ElectraNet has also undertaken an indicative assessment of the maximum amount of mining load that could locate on the Lower Eyre Peninsula and still result in Option 3 being preferred to other options.

These sensitivity tests are discussed below. In addition the results of the sensitivity analysis conducted on the discount rate used for the NPV analysis are provided in Appendix F.

[53] The values in this section are reported to the nearest percentage.

25% Lower Transmission Line Costs

ElectraNet has included a sensitivity test in relation to adopting a lower estimate of transmission line costs. Line costs are typically more difficult to cost than other network elements, such as substations or reactive power components.

The sensitivity of the RIT-T results to the following changes in assumptions has been investigated:

- Line costs being 25% lower for all options; and
- All other elements of the option costs remaining the same.

Table 6-6 below summarises the net market benefit in NPV terms for each credible option as well as its ranking under each scenario, assuming a 25% reduction in line costs.

The table shows that the assumption of 25% lower line costs does not affect the ranking of the options under any scenario, and also does not affect the rankings under the weighted average outcome.

Table 6-6: Net Market Benefit and Ranking of Each Credible Option Using 25% Lower Line Costs (NPV $m, 2011/12)

	Scenario 1: 30%		Scenario 2: 30%		Scenario 3: 30%		Scenario 4: 10%		Weighted Average	
	NMB	Ranking	NMB	Ranking	NMB	Ranking	NMB	Ranking	NMB	Ranking
1A	-$215	4	-$746	3	-$1,883	3	-$2,999	4	-$1,153	3
1B	-$229	5	-$768	4	-$1,904	4	-$2,902	2	-$1,161	4
2A	-$168	2	-$678	1	-$1,825	1	-$2,986	3	-$1,100	1
2B	-$183	3	-$711	2	-$1,846	2	-$2,889	1	-$1,111	2
3	-$124	1	-$1,479	5	-$3,540	5	-$6,587	5	-$2,202	5

**All circuits built to 275 kV to be operated at 132 kV for as long as possible.*

25% Lower On-Site Generation Costs

ElectraNet has tested the sensitivity of lower on-site generation costs to meet spot load requirements, in order to determine the impact on the RIT-T outcome. In particular this analysis tests the robustness of Option 3 being ranked as the least preferred option in all scenarios where additional spot load is assumed, ie, scenarios 2, 3 and 4.

This sensitivity test has assumed:

- On-site generation costs (both annual standby charges and annual usage charges) are 25% lower; and
- All other costs remain the same.

Table 6-7 below summarises the net market benefit in NPV terms for each credible option as well as its ranking under each scenario using these lower on-site generation costs. The assumption of 25% lower on-site generation costs does not affect the ranking of the options under any scenario, or the overall outcome of the RIT-T. Option 3 is still found to have a materially lower net market benefit under scenarios 2, 3 and 4, compared with the other options.

Table 6-7: Net Market Benefit and Ranking of Each Credible Option Using 25% Lower On-Site Mining Generation Costs (NPV $m, 2011/12)

	Scenario 1: 30%		Scenario 2: 30%		Scenario 3: 30%		Scenario 4: 10%		Weighted Average	
	NMB	Ranking	NMB	Ranking	NMB	Ranking	NMB	Ranking	NMB	Ranking
1A	-$269	4	-$844	3	-$2,007	3	-$3,161	4	-$1,252	3
1B	-$288	5	-$874	4	-$2,037	4	-$3,035	2	-$1,263	4
2A*	-$221	2	-$780	1	-$1,949	1	-$3,148	3	-$1,200	1
2B*	-$242	3	-$818	2	-$1,979	2	-$3,022	1	-$1,214	2
3	-$142	1	-$1,163	5	-$2,708	5	-$4,994	5	-$1,703	5

**All circuits built to 275 kV to be operated at 132 kV for as long as possible.*

Rebuilding Only a Portion of the Current 132 kV line

ElectraNet has tested the sensitivity of the results to an assumption that the costs of Option 3 could be lowered by assuming that only a quarter of the length of the existing line is rebuilt, with the remainder of the line kept operational through increased maintenance. As noted earlier (section 2.2), ElectraNet is currently undertaking studies in order to confirm the expected time at which the current line will need to be replaced, and to identify any options for extending the life of the asset.

This sensitivity again tests the robustness of Option 3 being ranked last in all scenarios where mining load is assumed, ie, scenarios 2, 3 and 4. Specifically, ElectraNet has assumed:

- The cost of the 132 kV line components of Option 3 are reduced by 75%;
- The network losses for Option 3 are trebled (to reflect the fact that the amount of high capacity line has been reduced); and
- All other costs (including operating costs) remain the same.

In reality, ElectraNet notes that if only a quarter of the existing line were to be replaced, then maintenance costs would be expected to be substantially higher. Assuming no change in maintenance costs is therefore a conservative assumption for this sensitivity analysis.

Table 6-8 below summarises the net market benefit in NPV terms for each credible option as well as its ranking under each scenario using these lower costs for Option 3. The assumed reduction in costs for Option 3 again does not affect the ranking of this option compared with others in under any scenario, and does not affect the overall RIT-T outcome.

Table 6-8: Net Market Benefit and Ranking of Each Credible Option Lower Costs of Option 3, Under Each Scenario (NPV $m, 2011/12)

	Scenario 1: 30%		Scenario 2: 30%		Scenario 3: 30%		Scenario 4: 10%		Weighted Average	
	NMB	Ranking	NMB	Ranking	NMB	Ranking	NMB	Ranking	NMB	Ranking
1A	-$269	4	-$844	3	-$2,007	3	-$3,161	4	-$1,252	3
1B	-$288	5	-$874	4	-$2,037	4	-$3,035	2	-$1,263	4
2A*	-$221	2	-$780	1	-$1,949	1	-$3,148	3	-$1,200	1
2B*	-$242	3	-$818	2	-$1,979	2	-$3,022	1	-$1,214	2
3	-$105	1	-$1,459	5	-$3,520	5	-$6,568	5	-$2,182	5

**All circuits built to 275 kV to be operated at 132 kV for as long as possible.*

25% Greater Line Costs for the 3rd 275 kV (600 MVA) Line Between Cultana and Yadnarie

ElectraNet has tested the sensitivity of the results to higher assumed costs for the 3rd 275 kV (600 MVA) line between Cultana and Yadnarie under Options 1A and 2A. The costs of this 3rd 600 MVA line may be higher, in the event that it were not possible to build the line on the same corridor as the other 275 kV 600 MVA line. This analysis tests the robustness of Option 2B being ranked second, for scenarios where this additional line is needed.

This sensitivity test has assumed:

- 25% higher costs of the 3rd 275 kV (600 MVA) line between Cultana and Yadnarie; and
- All other costs remain the same.

Table 6-9 below summarises the net market benefit in NPV terms for each credible option as well as its ranking under each scenario using these lower on-site generation costs. The assumption of 25% greater line costs for the 3rd 275 kV (600 MVA) line between Cultana and Yadnarie does not affect the ranking of the options under any scenario, or the overall outcome of the RIT-T.

Table 6-9: Net Market Benefit and Ranking of Each Credible Option Lower Costs of Option 3, Under Each Scenario (NPV $m, 2011/12)

	Scenario 1: 30%		Scenario 2: 30%		Scenario 3: 30%		Scenario 4: 10%		Weighted Average	
	NMB	Ranking	NMB	Ranking	NMB	Ranking	NMB	Ranking	NMB	Ranking
1A	-$269	4	-$844	3	-$2,007	3	-$3,200	4	-$1,256	3
1B	-$288	5	-$874	4	-$2,037	4	-$3,035	2	-$1,263	4
2A*	-$221	2	-$775	1	-$1,949	1	-$3,187	3	-$1,202	1
2B*	-$242	3	-$818	2	-$1,979	2	-$3,022	1	-$1,214	2
3	-$142	1	-$1,496	5	-$3,557	5	-$6,605	5	-$2,219	5

**All circuits built to 275 kV to be operated at 132 kV for as long as possible.*

Maximum Amount of Mining Load That Could Locate on the Lower Eyre Peninsula Before Network Augmentation Becomes Preferred to Option 3

Option 3 is ranked last under scenarios where mining load is assumed to locate on the Lower Eyre Peninsula (ie, scenarios 2, 3 and 4), due to the high cost of on-site mining generation required.

ElectraNet has undertaken an indicative assessment of the *maximum* amount of mining load (in MW) that could locate on the Lower Eyre Peninsula and still result in Option 3 being preferred over other options. Specifically, this sensitivity test has assumed:

- Scalability of the standby and usage charges estimated for the smallest amount of on-site mining generation estimated by SKM; ie, 100 MW; and
- Mining load comes online in 2015/16.

The results of this analysis indicate that a maximum of approximately 26 MW of mining load can locate on the Lower Eyre Peninsula before network augmentation would become the most economical option (ie, Option 3 is no longer preferred over other options).

ElectraNet notes that this indicative analysis assumes that the on-site mining generation costs are scalable. Specifically, this assumption ignores economies of scale and implicitly assumes that the per unit cost of gas generation does not increase with lower volumes of gas delivered. Alternatively, it might be more efficient for distillate generators to supply loads of less than 100 MW. However, either way the indicative analysis undertaken would underestimate the cost of on-site generation and, therefore would only decrease the MW at which Options 2A and 2B become preferred over Option 3

7. Proposed Preferred Option

The previous section has presented the results of the NPV analysis conducted for this RIT-T assessment.

The analysis has highlighted that the preferred option for investment on the Eyre Peninsula is heavily dependent on whether substantial new spot load is expected to connect in the area. There currently remains considerable uncertainty in relation to the connection of such additional spot load, with none of the current connection applications having reached committed status.

The RIT-T assessment has shown that if there was no expectation of substantial new spot load connecting on the Peninsula, then the lower capacity 132 kV option (ie, Option 3), which also includes a non-network component from 2017/18, would be the preferred option.[54]

Currently the network is expected to meet reliability criteria until 2017/18. The analysis also indicates that by implementing a DR program from 2017/18 and extending the current generation support contract, ElectraNet can delay the time at which it needs to undertake new network investment on the Lower Eyre Peninsula to address reliability concerns, to around 2020/21.[55] ElectraNet expects that it would need to finalise this RIT-T assessment by mid-2015 in order to procure demand response and generation support, in the absence of any commitment of major new spot load on the Peninsula.

As a consequence, there is no immediate need from a reliability perspective to finalise the RIT-T analysis. In light of the uncertainty in relation to future spot load developments, ElectraNet considers it prudent to delay the finalisation of the RIT-T process and the publication of the PACR until anticipated spot load developments become committed or prior to the time at which reliability constraints need to be addressed. Commitment by new spot load would remove any uncertainty as to the preferred investment option under the RIT-T.

ElectraNet is in on-going discussions with a number of potential connection applicants in relation to spot load developments. In the event that one or more of these spot loads do proceed, the analysis presented in this PADR shows that the option which would satisfy the RIT-T is Option 2A, ie, a 275 kV double-circuit 600 MVA line from Cultana to Port Lincoln North with a 3rd 275 kV 600 MVA line between Cultana and Yadnarie added when needed. All circuits built to 275 kV would initially be operated at 132 kV. The timing of operation at 275 kV would be dependent on the timing of new spot loads connecting in the Lower Eyre Peninsula.

The technical characteristics of this option are set out in section 5. The timing for the investment set out in section 5.4 is based on the dates requested in connection enquiries. In reality the timing of any augmentation is dependent on the spot loads making a firm financial commitment and whether they choose to fund pre-construction work ahead of full commitment. Depending on customer commitment to funding pre-construction works and the scope of network augmentation works ultimately required, a

[54] Option 3 also includes implementing a DR program from 2017/18 and extending the current generation support contract.

[55] ElectraNet is working with SA Power Networks to review the current load forecasts. The dates noted above will be reviewed in the light of the most recent forecasts, prior to any investment being implemented.

transmission network augmentation would likely take 2 - 5 years to complete from the time of customer financial commitment to connect a spot load.

In compliance with the NER requirements,[56] ElectraNet notes that this option is not likely to have a material inter-regional impact.

ElectraNet considers that if the current discussions progress to substantive load committing in the next 12-18 months, then the underlying assumptions used for the RIT-T analysis in this PADR are likely to remain relevant. However, the longer the delay, the greater the likelihood that the assumptions may require revision, and the analysis may need to be redone and/or the PADR reissued. ElectraNet currently envisages that the analysis in this PADR is likely to remain relevant until mid-2014.

The NER require that the PADR must set out the identity of the proponent for the preferred option, where the investment is for reliability corrective action. In relation to both Option 3 and Option 2A, ElectraNet is the proponent for the network components of the option. Prior to release of the PACR, ElectraNet intends to issue a tender for the DR component and the generation support component, for outcomes where these components are required. At this stage, both EnerNOC and IPR have identified themselves as potential proponents of DR and generation support, respectively.

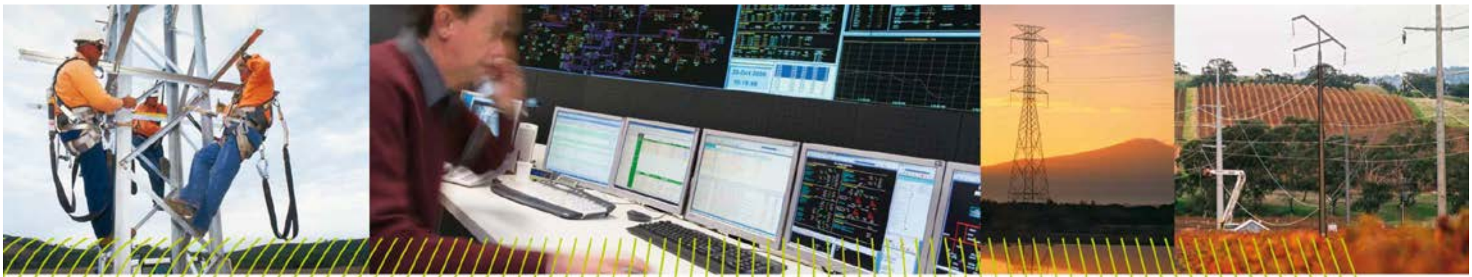
[56] NER 5.16.4(k)(9)(iii).

Lower Eyre Peninsula Reinforcement

Appendices

January 2013

Version 1.0



Appendix A Checklist of Compliance Clauses

This section sets out a compliance checklist which demonstrates the compliance of this Project Assessment Draft Report with the requirements of clauses 5.16.4(k) and (l) of the NER version 54.

NER Clause	**Summary of Requirements**	**Relevant Section in Report**
5.16.4 (k)	A Transmission Network Service Provider must prepare a project assessment draft report, which must include:	
	1. a description of each credible option assessed;	5
	4. a summary of, and commentary on, the submissions to the *Project Specification Consultation Report*;	3
	4. a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each *credible option*;	6
	5. a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	4.1
	6. the reasons why the TNSP has determined that a class or classes of market benefit are not material, where relevant;	4.3
	7. the identification of any class of market benefit estimated to arise outside the TNSP's region and quantification of the aggregate value of such market benefit;	6.2
	8. the results of an NPV analysis of the net market benefit of each *credible option* and accompanying explanatory statements regarding the results;	6.3
	9. the identification of the proposed *preferred option* and a statement that the *preferred option* satisfies the RIT-T: - if the option is likely to have a material inter-regional network impact; and - an augmentation technical report (if the TNSP has received such a report from AEMO).	7
5.16.4 (l)	The identity of the proponent for the preferred option.	7

Appendix B Definitions

Applicable regulatory instruments	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 NER.
AEMO	Australian Energy Market Operator
Base case	A situation in which no option is implemented by, on behalf of the transmission network service provider.
Commercially feasible	An option is commercially feasible under clause 5.15.2(a)(2) of the Electricity Rules 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 general 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: (ii) 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 economic benefit	Net economic 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.
Reliability corrective action	Investment by a Transmission Network Service Provider in respect of its transmission network for the purpose of meeting the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments and which may consist of network or non-network options.

Appendix C Total Demand Under Each Load Scenario

Table C-1: Total demand under each load scenario (MW)

Year	Scenario 1	Scenario 2	Scenario 3	Scenario 4
13/14	97	98	99	99
14/15	99	101	101	102
15/16	101	204	364	490
16/17	104	207	367	593
17/18	106	210	370	663
18/19	109	213	374	668
19/20	112	216	377	677
20/21	114	220	381	682
21/22	117	223	384	686
22/23	120	227	388	691
23/24	123	231	392	696
24/25	127	235	397	702
25/26	130	240	401	707
26/27	133	244	406	713
27/28	137	249	411	719
28/29	141	254	416	726
29/30	145	259	421	732
30/31	149	265	426	739
31/32	153	270	432	746
32/33	157	276	438	753

Appendix D Average SRMC of Generation in South Australia

Table D-2: Average SRMC in SA, ($/MWh, 2011/12$)

Year	Average SRMC in SA
13/14	46
14/15	47
15/16	48
16/17	49
17/18	55
18/19	57
19/20	58
20/21	60
21/22	64
22/23	66
23/24	68
24/25	70
25/26	70
26/27	71
27/28	74
28/29	76
29/30	77
30/31	83
31/32	84
32/33	87

Appendix E SRMC of the Marginal Generator in SA and NSW

Table E-3: SRMC of the Marginal Generator in SA and NSW, ($/MWh, 2011/12$)

Year	Average SRMC in SA – Torrens Island A	Average SRMC in NSW – Vales Point
13/14	73.19	41.35
14/15	73.64	41.35
15/16	75.86	41.35
16/17	76.68	41.35
17/18	108.49	41.35
18/19	112.44	41.35
19/20	113.82	48.73
20/21	118.27	48.73
21/22	128.91	48.73
22/23	131.89	48.73
23/24	133.95	48.73
24/25	136.09	60.37
25/26	138.49	60.37
26/27	140.95	60.37
27/28	143.57	60.37
28/29	151.74	60.37
29/30	156.6	73.37
30/31	158.67	73.37
31/32	163.17	73.37
32/33	167.85	73.37

Appendix F Sensitivity of results to changes in the discount rate

Table F-4: Net Market Benefit and Ranking of Each Credible Option Using Discount Rate of 6.13%, Under Each Scenario (NPV $m, 2011/12)

	Scenario 1: 30%		Scenario 2: 30%		Scenario 3: 30%		Scenario 4: 10%		Weighted Average	
	NMB	Ranking	NMB	Ranking	NMB	Ranking	NMB	Ranking	NMB	Ranking
1A	-$301	4	-$1,013	3	-$2,651	3	-$4,288	4	-$1,618	3
1B	-$323	5	-$1,043	4	-$2,679	4	-$4,155	2	-$1,629	4
2A*	-$243	2	-$950	1	-$2,590	1	-$4,275	3	-$1,563	1
2B*	-$267	3	-$988	2	-$2,618	2	-$4,141	1	-$1,576	2
3	-$186	1	-$2,073	5	-$4,746	5	-$8,862	5	-$2,987	5

**All circuits built to 275 kV to be operated at 132 kV for as long as possible.*

Table F-5: Net Market Benefit and Ranking of Each Credible Option Using Discount Rate of 13%, Under Each Scenario (NPV $m, 2011/12)

	Scenario 1: 30%		Scenario 2: 30%		Scenario 3: 30%		Scenario 4: 10%		Weighted Average	
	NMB	Ranking	NMB	Ranking	NMB	Ranking	NMB	Ranking	NMB	Ranking
1A	-$236	4	-$745	3	-$1,666	3	-$2,573	4	-$1,052	3
1B	-$253	5	-$775	4	-$1,696	4	-$2,455	2	-$1,063	4
2A*	-$196	2	-$681	1	-$1,612	1	-$2,561	3	-$1,003	1
2B*	-$214	3	-$718	2	-$1,641	2	-$2,442	1	-$1,016	2
3	-$114	1	-$1,195	5	-$2,934	5	-$5,428	5	-$1,816	5

**All circuits built to 275 kV to be operated at 132 kV for as long as possible.*