EMCa energy market consulting associates

SA Power Networks Regulatory Proposal 2015 – 2020

Peer review of AER analysis for Kangaroo Island – Network security second undersea cable

[redacted]

Report to

Australian Energy Regulator

from

Energy Market Consulting associates

This report has been prepared to assist the Australian Energy Regulator (AER) with its determination of the appropriate revenues to be applied to the prescribed distribution services of SA Power Networks. The AER's determination is conducted in accordance with its responsibilities under the National Electricity Rules (NER). This report covers a particular and limited scope review as defined by the AER and should not be read as a comprehensive assessment of SA Power Networks' project or associated expenditure.

To the extent that this report utilises quantitative data, it relies on information provided to EMCa by the AER and which in turn is sourced from SA Power Networks. EMCa disclaims liability for any errors or omissions, for the validity of information provided to EMCa by other parties, for the use of any information in this report by any party other than the AER and for the use of this report for any purpose other than the intended purpose.

In particular, this report is not intended to be used to support business cases or business investment decisions nor is this report intended to be read as an interpretation of the application of the NER or other legal instruments. EMCa's opinions in this report include considerations of materiality to the requirements of the AER and opinions stated or inferred in this report should be read in relation to this over-arching purpose.

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About EMCa

Energy Market Consulting associates (EMCa) is a niche firm, established in 2002 and specialising in the policy, strategy, implementation and operation of energy markets and related network management, access and regulatory arrangements. EMCa combines senior energy economic and regulatory management consulting experience with the experience of senior managers with engineering/technical backgrounds in the electricity and gas sectors.

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Findings

Background

1. SA Power Networks has proposed a second subsea cable to be installed from Fisheries Creek to Cuttlefish Bay in 2017/18 to provide network security to Kangaroo Island.

2. We have reviewed the supporting information provided by SA Power Networks in its asset management plan, together with the supporting business case for the new subsea cable to Kangaroo Island and the AER's own analysis. We have considered the technical aspects of the business cases, as proposed by SA Power Networks, and assessed the economic analyses prepared by the business and by AER staff.

3. In its documents, SA Power Networks has set out its proposal to install a new subsea cable that:

   - is designed for 66kV (but will be initially operated at 33kV) as part of a broader strategy to strengthen the surrounding sub-transmission network;
   - has a design rating of 40 MVA at 66kV (20MVA at 33kV) to account for growth in electricity demand; and
   - will be installed in similar conditions and location to the existing cable.

Our assessment of SA Power Networks' NPV analysis

4. We have reviewed the net present value (NPV) analysis provided by SA Power Networks and consider it to be incomplete and not suitable to assess the optimum timing of the cable replacement. Specifically, we consider that:

   - the supplied methodology (Models 1, 2 and 3) for assessment of the optimal timing for replacement of the subsea cable does not provide a consistent assessment of the probability, consequences and combined outcome of cable failure and the timing of its replacement;
   - the options included for Model 3 do not consider prudent alternatives to the preferred cable replacement scenario; and

- the partial spreadsheet analyses (Model 1 and Model 2) and the three options selected for full assessment (Model 3) are not comparable in terms of assumptions, costs and timing.

AER preliminary assessment matters

5. We consider that the AER's application of a probability of failure into the NPV analysis and it's assessment of the cable justification is appropriate and we have incorporated this into our revised NPV analysis.

Our revised NPV analysis

6. We have made adjustments to SA Power Networks' analysis to establish a new base case NPV in which we compare alternative options for cable replacement and an alternative function for modelling the probability of the cable failure event.

7. We have made an assessment of two possible deferment options to understand the sensitivity of the timing of the cable replacement on the NPV analysis. We considered the impact of deferral of the cable replacement by two years (i.e., to the end of the forthcoming RCP) and by five years (i.e., into the subsequent RCP). This analysis suggests that there is not an economic benefit (in NPV terms) to be gained from deferral.

8. We were not asked to review the basis of SA Power Networks' cost estimation and forecasting systems, or the engineering design proposed for the subsea cable and other cost parameters. We have therefore relied upon, and applied, the costs provided by SA Power Networks in our analysis. We observe that the inclusion of alternative generation cost assumptions may have a material impact on the analysis.

9. We also find that the justification and analysis provided by SA Power Networks does not include adequate consideration of:

    i. alternative options - including evaluation of non-network options and the potential impact of energy storage technologies;

    ii. the ongoing risk to network security following loss of a single supply cable as part of the radial connection to the Kangaroo Island community; and

    iii. benefits associated with the longer term development of the sub-transmission network.

10. We have not assessed the impact of any prospective changes to the NPV analysis regarding these matters.

11. We consider that the risk mitigation measures proposed by SA Power Networks regarding improving the cable repair time, and for increasing the available generation capacity at Kangaroo Island, are reasonable.

Overarching findings

12. We consider that, whilst the justification and analysis provided by SA Power Networks has inadequacies, the project is likely to be required within the 2015-

20 regulatory control period (RCP).[1] Accordingly, we consider that it would not be reasonable in setting the capital expenditure allowance for SA Power Networks to assume that this project can be deferred into the subsequent RCP.

[1] Our limited scope review did not extend to the consideration or assessment of alternate options for the supply of electricity to Kangaroo Island.

1 Introduction

1.1 Purpose and scope of requested work

13. The purpose of this report is to provide the AER with advice on the analysis and modelling of the Kangaroo Island cable replacement. The assessment is intended to assist the AER in its own analysis of the capital expenditure included for this augmentation project as an input to its Draft Decision on SA Power Networks' revenue requirements.

14. The AER has sought peer review by EMCa of the capital project submission for SA Power Networks for the second subsea cable to supply Kangaroo Island. The purpose of the peer review is to:

- provide an independent review of the material provided by SA Power Networks to support the justification of the project, including NPV analysis;
- provide an independent review of the material provided by the AER, following its own analysis; and
- provide our findings in relation to our technical and economic assessment of the NPV analysis for the project, as nominated in the scope of work.

15. This advice and the assessment that we have undertaken is based on a limited scope review in accordance with the terms of reference. It does not take into account all factors or all reasonable methods for determining an expenditure allowance in accordance with the National Electricity Rules (NER). We understand that the AER will establish a capital expenditure allowance for SA Power Networks based on assessments undertaken by its own staff.

1.2 Our approach

16. In considering this matter, we have:

- identified relevant supporting information, including reference to SA Power Network's RP and the AER's own analysis;
- considered the technical aspects of the business case, as proposed by SA Power Networks, and assessed the economic analyses prepared by the business and by AER staff; and
- considered the modelling, assumptions and sensitivity of the NPV analysis.

17. The AER has specifically asked us to consider the material provided by SA Power Networks in its regulatory proposal and project justification report in order to:

- assess the underlying methodology for inclusion of the probability of subsea cable failure into the NPV analysis;
- subject to that assessment, review the application by AER staff of the probability of failure into the NPV analysis; and
- review AER staff's justification and preliminary conclusion that delaying the cable replacement until after 2020 is likely to minimise the NPV of costs to consumers.

18. Based on the analysis by AER staff, we have considered the extent to which the prospective deferral of this project until after the 2015–20 RCP would minimise the NPV of the cost to consumers.

19. The limited nature of our review does not extend to review of all options and alternatives that may be reasonably considered by the DNSP. However, where we have identified information that is material to our findings, we have referenced this information accordingly.

1.3 Structure of this report

20. Our main findings are summarised at the beginning of this report.

21. In section 2, we provide a contextual overview of SA Power Networks' Regulatory Proposal in relation to this project, along with the hypotheses and focus issues that the AER has asked us to assess.

22. In section 3, we describe our review of the technical considerations, modelling, assumptions and sensitivity of the NPV analysis supplied for the Kangaroo Island cable replacement project.

23. In Appendix A, we list the documents that we reviewed as part of our assessment.

24. In Appendix B, we provide the supporting analysis for the capex adjustment to SA Power Networks' Model 3 RIT-D Option 1 base cost, together with our input assumptions and results for the two-year and five-year deferral options.

2 Background

2.1 Introduction

25. This section provides context to the review that follows. Reference data was sourced from SA Power Networks' Regulatory Proposal 2015-2020.

26. Initially, we describe the project information supplied by SA Power Networks, then provide our views on SA Power Networks' proposal based on the information supplied to the AER, together with any explanations and responses that SA Power Networks subsequently provided to the AER in response to information requests.

27. Subsequently, we summarise the focus issues and hypothesis that the AER has already developed from its initial assessment, and which the AER has asked us to review.

2.2 SA Power Networks' proposed new subsea cable to Kangaroo Island

28. SA Power Networks proposes to install a new subsea cable to Kangaroo Island to secure supply to the island as part of its "*Keep the power on for South Australians*"[2] capital expenditure. The total project cost proposed is $47.2m, or approximately 6% of the total proposed capex for the RCP 2015-2020.

29. SA Power Networks included expenditure in the current RCP for installation of a new subsea cable; however, it states that the AER rejected the proposed investment at that time.

[2] SA Power Networks Regulatory Proposal 2015-2020, page 69

30. SA Power Networks states that it has undertaken extensive review of the alternative options, concluding from its cost benefit analysis that "*investing in a new submarine cable before the existing cable fails is the optimal approach*".[3]

31. Ensuring the security of supply to Kangaroo Island is one of five strategic projects included in the 2015-2020 RP, representing 48% of the $98.5m forecast for strategic programs. SA Power Networks describes the project in its Asset Management Plan AMP 2.1.03.

32. SA Power Networks has identified the "*Kangaroo Island cable failure event*" as one of six pass-through events in its RP.[4] We were not asked to review the matter of classification of failure of the subsea cable supplying Kangaroo Island as a pass-through event.

33. In its cost benefit analysis, SA Power Networks claims that the installation of a second subsea cable in 2017/18, rather than allowing the cable to run to failure prior to replacement, delivers the lowest cost to SA Power Networks' customers unless the existing cable life extends beyond 2034/35.

34. SA Power Networks has provided analysis of six options, as summarised below:

- Option 1 – do nothing;
- Option 2 (recommended) - install a second submarine cable from Fisheries Creek to Cuttlefish Bay in 2017/18;
- Option 3 - run to failure, but provide the capital and operating expenditure to provide for a faster response time to reinstate supply (four months);
- Option 4 – install dedicated renewable energy sources (non-network solution) with no link to the mainland;
- Option 5 - install a second submarine cable from Fisheries Creek to Cuttlefish Bay before failure and a 66/33kV substation and line work upgrade from Cape Jervis to Penneshaw; and
- Option 6 - install a second submarine cable via an alternative cable route from Fisheries Creek to Kingscote.

35. SA Power Networks has recommended Option 2 as the lowest cost to consumers based on its net present value (NPV) analysis.

2.3 AER focus issues

36. The AER considers that SA Power Networks has not adequately assessed the risk of the failure of the subsea cable. As evidence of the inadequate risk analysis by SA Power Networks, the AER observed that SA Power Networks' NPV analysis would justify a second cable in any year irrespective of the condition of the existing cable.

[3] SA Power Networks Regulatory Proposal 2015-2020, page 90

[4] SA Power Networks Regulatory Proposal 2015-2020, page 274

37. The AER has reproduced SA Power Networks' NPV results and included a probability weighted cost of the failure of the subsea cable.

38. In its initial assessment, the AER formed a view, on the basis of the revised NPV analysis and assumptions of reasonable cable repair and replacement time, that the proposed project expenditure could be prudently deferred to the subsequent RCP.

39. The AER engaged with SA Power Networks to better understand the assumptions and basis for the recommended option. We have included the additional information provided by SA Power Networks in our analysis.

40. Having established the potential for the new subsea cable to Kangaroo Island to be constructed in the next RCP, the AER has requested that EMCa review the robustness of the assumptions and NPV analysis associated with the project justification.

2.4 Summary

41. SA Power Networks has proposed a new 66kV subsea cable, to be initially operated at 33kV and installed by 2018, to secure the electricity supply to Kangaroo Island. Whilst SA Power Networks has alternative means of supplying power to the island in the event of failure of the undersea cable, it considers that installing the new cable is the preferred option based on its economic assessment.

42. The AER has identified the potential for an alternative approach to the assessment of the risk of the cable failure, and requested that we assess the impact of this approach on the NPV analysis.

3 Review of project justification and modelling

3.1 Introduction

43. In this section, we provide the results of our review of the technical considerations and modelling assumptions for the new subsea cable for Kangaroo Island.

44. A summary of the information that we relied upon in our review is provided in the Appendices.

3.2 Network overview of supply to Kangaroo Island

3.2.1 Network overview

45. Kangaroo Island has a peak demand of 7.2MW (January 2014) and an average load of 3.8MVA. The island is supplied from the mainland via a 50km radial 66kV sub-transmission line between Wilunga and Cape Jervis and 90km of radial 33kV sub-transmission line between Cape Jervis and Kingscote - including 15km of 33kV subsea cable between Fisheries Creek (mainland) and Cuttlefish Bay (Kangaroo island).

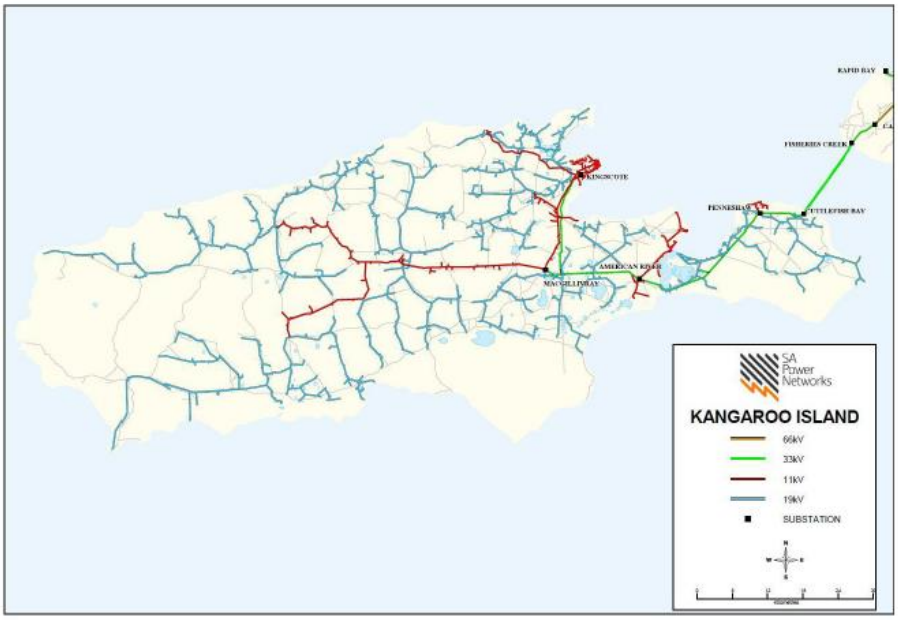
46. The 33kV sub-transmission network on the island connects to 33/11kV substations at Cape Jervis, Penneshaw, American River, MacGillivray and Kingscote. There are also a number of 33/19.1kV SWER systems on the island. The island has existing diesel-fired generation capacity of 5.4MW[5]

[5] SA Power Networks proposes to increase the capacity of the Kingscote power station to 7.2MW during 2015, with an N-1 capacity of 6MW.

located at Kingscote power station. The generating plant was designed to provide standby capacity and cannot meet the peak demand on the island. If operated for long durations, the generating plant will be subject to increased outages for routine maintenance.

47. There are also a number of off-grid customers on the island, totalling 6.4MVA of private, isolated generation.

Figure 1: Kangaroo Island network overview



Source: Attachment 1: Kangaroo Island sub-transmission supply System, SA Power Networks Kangaroo Island AMP 2.1.03

3.2.2 Subsea cable

48. The 33kV subsea cable is rated for 10 MVA and is 22 years old, with an expected design life of 30 years (2023). The cable was installed in 1993 to replace the original cable installed in 1965. As a radial network, any loss of the cable or other sub-transmission element will result in the instantaneous loss of electricity supply to Kangaroo Island from the mainland.

49. The first 33kV submarine cable (installed in 1965) had an electrical failure in 1987 after 22 years in service. It was subsequently repaired and returned to service. In 1989, the damage to the cable was further investigated, indicating corrosion and erosion of the armouring to such an extent that the cable was deemed to have reached the end of its economic life.

50. A new cable was installed in May 1993. The old cable was used as a backup for its remaining limited life. The old cable finally had a mid-ocean fatal failure in 2002 (suspected cable joint failure) after 37 years in service.

51. The cable is laid directly on the seabed, which leaves it exposed to possible damage. Based on CIGRE Technical documentation, SA Power Networks suggests that the ‘unprotected’ cable is exposed to a number of risks, including possible damage from: (i) both shipping and pleasure craft anchors; (ii) mechanical and vibration effects of subsea cables moving with the tides; (iii)

external abrasion of the outer jacket of the cables on the seabed; (iv) suspension of the cable due to irregularities of seabed; and (v) corrosion due to tides and waves.

52. SA Power Networks states that a "*Hydrographical survey indicates that approximately 2.6km of the cable is laid on the sea bed with a depth of less than 25m (shallow water). The remaining 12km of cable is laid and buried on the sea bed with a depth of more than 25m (deep sea) with a maximum depth of 61.5m. Approximately 13.9km (95%) of the cable is now completely buried under sandy sea floor.*"[6] The degree of protection afforded to the cable by being buried on the sandy sea floor through movement of the sea floor, if any, is not known.

53. SA Power Networks states that a catastrophic failure of the Kangaroo Island subsea cable "*will incur substantial costs to repair and maintain supply via the diesel power station over a long period*".[7] SA Power Networks advises that restoration of electricity supply from the mainland could take: (i) up to 12 months to repair for a deep sea fault as it requires a special cable laying ship from overseas to recover, repair and reinstate cable;[8] and/or (ii) up to 24 months to replace the cable.[9]

54. To date, the 33kV subsea cable has had an incident free service life. However, SA Power Networks considers that the existing radial 33kV cable is nearing its design life expectancy of 30 years.[10]

3.3 Technical considerations

3.3.1 Long term strategy

55. We observe that the selection of a design voltage of 66kV for the subsea cable, which is likely to provide more effective voltage support and power transfer capability, appears to be consistent with a longer term strategy to strengthen the sub-transmission network in the area.

56. The asset management plan includes the addition of a proposed 66kV sub-transmission network on the island to provide N-1 security and to meet demand growth beyond 2035. The plan includes assessment of the condition of the 33kV sub-transmission network and proposes that it is nearing end of life. SA Power Networks advises that the installation of a new 66kV sub-transmission network will avoid lengthy periods of local generation while the existing 33kV sub-transmission is being replaced.

57. SA Power Networks proposes that the associated projects will be completed in stages beyond 2025, and which are not included in its RP. The justification for

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[6] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03) page 9

[7] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03) page 8

[9] AER SAPN 037_CONFID Attachment 4_KI Cable RIT-D Analysis Report Rev1 v1.0 cable repair time (options 2 & 3) is 12 months and cable replacement time (all options) is 2 years, page 2

[10] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03), page 10

selection of the higher cable design voltage of 66kV, and any corresponding increase in expenditure associated with this design, was not clearly evident.

3.3.2 Understanding the project drivers

58. An underwater inspection of the existing cable was completed in 2012. From Fisheries Creek, the current condition of the laid cable appears to support organic marine growth "*but minor corrosion was evident intermittently with some of the cable's outer sheath fibre being exposed*."[11] At approximately 800 metres from Fisheries Creek to the Cuttlefish Bay shore, the cable is completely buried under the sand. The inspection identified that: "*Only 5% (800 metres) of the cable route length was successfully located and inspected. As most of the 33kV submarine cable route is now buried under the sand, the condition of the cable in the middle of Backstairs Passage is relatively unknown.*"[12]

59. Visual inspection of the buried portions of the cable is not possible. SA Power Networks advises that it does not have a condition monitoring program in place for the subsea cable and was not aware of any effective condition monitoring approaches for subsea cables of this length elsewhere.

60. SA Power Networks suggests that layers of organic marine material over buried cables "*may have the effect of thermal insulation and consequential overheating of the cable*."[13] No condition based evidence or history of overheating is provided to support this assertion.

61. SA Power Networks recommends the installation of a new submarine cable by 2017/18 at an estimated cost of $47.5m (2013 $). The existing radial 33kV submarine cable is nearing its design life expectancy of 30 years, with significant consequences if the cable fails prematurely. SA Power Networks states that: "*A catastrophic cable failure will incur substantial cost to repair and run limited generation over a long period which will in turn impact on tourism, business, community and the economic development of Kangaroo Island*".[14]

62. SA Power Networks contends that after the new cable installation, the Kingscote power station will be kept to maintain its ability to manage failure of the new cable. While the old cable remains in service, it will be used to assist the power station in its maintenance strategy (managing total load). SA Power Networks states that: "*Any availability of the old submarine cable beyond 2018 will allow deferral of the power station capacity upgrade and therefore provide cost advantages to our customers. However, once the old cable fails, the need to upgrade the power station will be necessary to keep pace with the increasing Kangaroo Island load.*"[15]

[11] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03) page 11

[12] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03) page 11

[13] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03) page 11

[14] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03) page 6

[15] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03) page 8

63. We were advised that the primary driver of expenditure was the consideration of the lowest NPV outcome.

3.3.3 Demand forecast

64. We observe that the proposed demand forecast over the period 2014/15 (7.8MVA) to 2033/34 (10.23MVA) assumes an average annual growth rate of 1.42%. We were not asked to review the demand forecast.

65. We note that the demand forecast is not a driver of the proposed expenditure, and that SA Power Networks' own analysis suggests that the current capacity will not be exceeded until 2032/33.

66. SA Power Networks states that: "*The new submarine cable is proposed to be rated at 66kV but energised at 33kV initially. The planned rating of the cable would be 40MVA at 66kV and 20MVA at 33kV to provide sufficient capacity for its 30 year life. The existing 33kV cable will be used to assist the power station in its backup strategy (managing total load) until it fails.*"[16]

67. We observe that the justification for the cable specification does not appear to have been included in the supplied analysis. It would appear to be rated at a much higher level than the demand forecast would suggest is necessary. SA Power Networks has not provided information regarding the justification and/or cost implications of choosing this rating.

3.3.4 Risk assessment

68. SA Power Networks has identified the loss of the subsea cable as a major risk, and assessed the risk level as high driven primarily by the financial and reliability consequence(s) of an extended outage.

69. SA Power Networks has supplied limited information on the condition of the existing cable. The first cable had an electrical failure in 1987 after 22 years in service and, after repair, continued to operate until total failure in 2002. This reflects a total of 37 years in service. In this respect, the existing cable has performed well. The probability-weighted risk assessment approach regarding the economic life of the existing cable (30 years) appears reasonable.

3.3.5 Cable repair

70. SA Power Networks advises that the ideal (reported) repair time of subsea cables around the world is approximately two to four months. However, SA Power Networks also advises that the unique location of its cable, combined with the limited number and/or availability of suitable cable repair vessels, could result in a cable repair time of one year or more.

71. SA Power Networks states that the cable is located in an area of adverse weather. It states that "*The Backstairs Passage is well known for its challenging sea conditions due to high energy swells penetrating in the St*

[16] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03) page 14

Vincent Gulf from Southern Ocean,"[17] requiring identification of a suitable weather window necessary to complete the repair work. In its RP documentation, SA Power Networks presents three primary fault location and cable repair scenarios, with a corresponding assessment of the likely repair times, as summarised below:

- shallow water cable fault (2 months);
- deep ocean cable fault (12 months); and
- inability to locate a cable fault as a result of the cable being deeply buried – initiating the replacement of a new cable (24 months).

72. Subsequently, SA Power Networks has advised that a 'fast cable repair' option of 4 months for repair of a deep ocean fault is possible, assuming that a number of pre-planning activities are undertaken. These activities include the advance purchase of new spare cable and cable-joints, a retainer for repair services and standby generation.

73. The SA Power Networks base case assumption is $11.4m cost for a 12 month repair. A fast response option was $5.9m for the advance purchase of repair cable, including its storage, to reduce the time of repair to 4 months and the total repair cost to $7.4m.

74. SA Power Networks has sought independent advice in relation to the cable repair times proposed. Based on our own experience and review of available literature, we have observed repair times of up to 60 days (often related to installations in Europe or New Zealand in adverse weather conditions). We consider that the conditions described by SA Power Networks suggest that a repair time between 2 and 4 months is reasonable.

3.3.6 Cable installation

75. SA Power Networks advises that it has sought advice on the manufacture and installation of a new cable. Combined with its own experience replacing the previous cable, SA Power Networks has nominated an installation time of two years.

76. This nominated installation time has varied between 12 months, 18 months and two years in SA Power Networks' NPV analyses. The variability in this assumption is an area of concern.

77. A cable installation time of two years was assumed in our analysis based on:

- the use of 2 years in the SAPN AMP document; and
- verification by SA Power Networks staff[18] that this installation timing reflects its working assumption and incorporates advice from cable manufacturers and other advisors.

78. Whilst we were not required to review the requirements for installation of a new subsea cable, nor form an opinion on the likely installation time, we consider

[17] AMP page 12

[18] Included in a teleconference between AER and SA Power Networks' staff

that this time is towards the upper end of what we would expect to see, including manufacturing time. We have not seen evidence of the likely components of the proposed installation time, or assessment of prospective methods for optimisation.

79. We note that the AER has requested further clarification from SA Power Networks regarding its ability to purchase and store lengths of subsea cable to minimise the cable installation time.

3.3.7 Standby generation

80. In 2005/06 and 2006/07, SA Power Networks installed 5.4MW of remotely controlled backup generation at Kingscote power station to supply the island in the event of an outage of the sub-transmission connection to Kangaroo Island. These generators alone would be insufficient to supply the total Kangaroo Island load in the event of a prolonged outage.

81. To ensure that sufficient generation capacity is available to meet the total estimated load, a fourth generating unit is planned for installation during 2015 (increasing N-0 capacity to 7.2MW and N-1 capacity to 6MW).

82. The Kingscote power station was designed for standby capacity for short durations of operation for either network support or interruptions. After 10 days of operation, the generating units need to be progressively taken out of service for maintenance. In the event of a prolonged outage, at least 2.6MW of mobile generation would need to be installed at Kingscote substation, including additional operating and maintenance staff to operate the power station and the additional gensets.

83. SA Power Networks states that the total additional cost to maintain local electricity supply to Kangaroo Island for 12 months without the use of the subsea cable is estimated to exceed $31.8m ($2013), with fuel costs being the most significant portion. SA Power Networks estimates that the VCR cost for not having secure supply at Kangaroo Island - based on one year of generation with the average Kangaroo Island load at 3.8MW - would be $3.4m ($2013).[19]

84. GHD was engaged by SA Power Networks to obtain a detailed specification for the proposed 66kV submarine cable.[20] Budget prices for the turn-key design, supply, delivery, installation and commissioning of a 40MVA 66kV submarine cable, initially energising at 33kV with a capacity limit of 20MVA along with associated modifications to the existing 33kV network, is $47.5m ($2013).[21]

85. The required environmental assessment by GHD and approvals to allow the cable project to be implemented in the forthcoming RCP has commenced and is expected to be approved by the end of 2015. SA Power Networks advises that it expects to have the necessary approved specification and required

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[19] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03) page 13

[20] 20 108a KI Cable Constructability Assessment report_AMP ref 13; 20 108b KI Cable Route Study report_AMP ref 14 (see SAPN 20.108 CONFID KI Supporting evidence)

[21] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03) page 14

approvals to implement the cable replacement process within approximately two years of the decision to proceed with the project.

3.4 Our assessment of the supplied models

3.4.1 Matters raised by AER

86. The AER raised a number of concerns with the NPV analysis supplied by SA Power Networks for the proposed expenditure, including that:

   i. there is no assessment of probabilities of cable failure risk within the analysis;

   ii. the analysis assumes additional costs which are already covered according to the Emergency Response Plan; and

   iii. the assumptions on costs appear conservative and include figures that are not supported or explained.

87. The AER provided an initial probability-weighted NPV analysis[22] to assess the likelihood of failure and resulting cost of replacement. The AER aggregated the probability-weighted cost of failure for the remaining life of the asset from 2015/16.

88. The AER assessment provided an important initial challenge to SA Power Networks' assumptions on probability of failure, time to repair and cost assumptions. However, as a whole-of-life assessment, it did not provide a basis for options evaluation. The approach assumed a probability of failure that allowed the cable to operate well beyond its design life. This was not characteristic of a wear, corrosion or age probability distribution profile which has an increasing probability of failure.

89. The AER and SA Power Networks exchanged a number of versions of NPV analyses, providing partial analysis and ranking of cable repair and replacement options according to time. Iterations of these spreadsheets considered both the time required for cable replacement and different probability distribution criteria. While they guided the analysis, on their own, they are not a complete assessment of the options.

90. On 6 March 2015, the AER "*shared its analysis and findings with SA Power Networks and invited comments from SA Power Networks before the Board formally makes its preliminary decision*." SA Power Networks produced three models that responded to the AER's analysis and provided alternative assessments. We have reviewed both the AER's initial analysis and SA Power Networks' models, as described below.

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22 KI analysis SAPN 006 email Attachment (12 February 2015)

3.4.2 Models supplied by SA Power Networks

Model 1 - Cable replacement time of two years[23]

91. The AER preliminary analysis provided a ranked assessment of the probability weighted NPV of cable failure and replacement of the cable in each year from 2015/16. This was compared to SA Power Networks' preferred option for replacement in 2018/19, which has a higher NPV. A conservative (high) linearly increasing probability of cable failure (100% failure by 2023) was used to assess the optimum timing of cable replacement.

92. SA Power Networks reproduced the AER's preliminary analysis, but challenged the VCR and generation cost assumptions. SA Power Networks proposed a cable replacement time of two years and calculated a higher VCR of $6.8m and generation cost of $59.4m from that assumption. This re-established the SA Power Networks preferred option as having a lower (net) cost.[24]

93. SA Power Networks' revised analysis reflects a shift in assumptions that is inconsistent with the other model assessments. The base assumption (used in Model 3 RIT-D assessment) is that the cable replacement will take two years to install and that the repair will be completed in 12 months (Option 2). A faster cable repair time has been included as an alternative option (Option 3).

94. Reviewing this model and the AER's initial analysis, we found that the cumulative probability-weighted cost of failure was calculated and applied as a single cost in the year being considered. We consider that the PV cumulative cost of failure should include the weighted probability of failure and cash flow in each preceding year, not just a total in the year being assessed. As such, we consider that the methodology is not complete and is unlikely to lead to the selection of the optimal option.

Model 2 – Normal distribution probability function of 18 months to repair the cable[25]

95. The SA Power Networks model further develops the AER's preliminary analysis, by replacing the simplified linear probability profile with a normally distributed probability profile. The VCR ($5.1m) and generation ($47.5m) costs are assessed on the assumption of a cable replacement time of 18 months.

96. This analysis considers the installation of the second cable by incrementally assessing the probability and cost of failure in each prior year until replacement. The NPV is the expected value of the probability-weighted cost of failure up to cable replacement and assuming an 18 month repair and/or cable replacement. SA Power Networks has provided a normal probability distribution function to assess the incremental probability of failure in each year. The distribution utilises an average life of 30 years and a standard

[23] Kangaroo Island NPV risk adjusted (AER) and AER SAPN 037_CONFID Attachment 1_Kangaroo Island NPV risk adj 2 Years v1.0 (SAPN)

[24] Calculated in NPV terms.

[25] AER SAPN 037_CONFID Attachment 2_KI NPV risk adj norm dist 18mths Rev2 v1

deviation of 5.5 years (i.e., square root of the average life). It is correctly adjusted for the period of analysis, assuming no prior failures.

97. The analysis by SA Power Networks represents another shift in assumptions for cable replacement. While the model provides the expected value of the probability-weighted cost of failure up to cable replacement, it remains a partial analysis. It only considers a cable replacement strategy of 18 months for cable failure and the higher replacement generation cost for that period. It does not consider the 12 month and 4 month repair strategies associated with deferred replacement. As such, the methodology is incomplete and is unlikely to lead to the selection of the optimal option.

Model 3 - Kangaroo Island RIT-D evaluation over 30 years[26]

98. The '*Kangaroo Island RIT-D Evaluation 30 years'* addresses SA Power Networks' original option and includes a detailed NPV analysis in line with Regulatory Investment Test – Distribution (RIT-D) principles. The analysis incorporates a normally-distributed probability profile for cable failure based on the standard deviation of the square root of the expected life of the cable.[27]

99. In this model, SA Power Networks considered three options for replacement of the existing subsea cable:

- Option 1 - Cable replacement in 2018/19 (the preferred option);
- Option 2 - Run to failure, then initiate cable repair (12 months) or cable replacement over two years; and
- Option 3 - Run to failure, but provide the capital and operating expenditure to provide faster response time (e.g., four months) for cable repair, with cable replacement unchanged over two years.

100. There is no analysis that compares the preferred timing to replace the cable in 2018/19 with another time for replacement. As such, the methodology is incomplete and as presented is unlikely to lead to the selection of the optimal timing for cable replacement.

101. In the absence of better information from SA Power Networks, we have applied Model 3 – Option 1 as a primary reference for the base case NPV assessment. The principal assumptions of this model are provided in Appendix B. SA Power Networks' unadjusted NPV assessment for its options 1, 2 and 3 are provided in Table 1 below.

Table 1: SA Power Networks' NPV assessment of Option 1, 2 and 3 ($m)

Option	Description	Capital	O&M	Generation	VCR	Losses	Total
Option 1	Cable replacement in 2018	$43.78	$8.69	$0	$0	$0	$52.47
Option 2	Run to failure	$42.10	$7.89	$24.10	$1.49	$0	$75.59
Option 3	Run to failure with quick response	$44.87	$8.52	$8.64	$0.32	$0	$62.34

Source: EMCa analysis of Networks 037_CONFID Attachment 3 KI RIT-D Evaluation 30 years Rev2 v1.0

[26] AER SAPN 037_CONFID Attachment 3 KI RIT-D Evaluation 30 years Rev2 v1.0

[27] AER SAPN 037_CONFID Attachment 4_KI Cable RIT-D Analysis Report Rev1 v1.0

102. We made a number of observations regarding SA Power Networks' Option 1 (preferred option) analysis, which led us to develop an alternative base for the purposes of assessing options, as follows:

- SA Power Networks' cable replacement option (Option 1) includes a principal assumption that all capex related to back-up generation and voltage control is avoided through to 2042. However, we consider that the probability of failure of the original cable applies equally to all options. The continuing availability of the original cable to avoid capex to 2042 cannot be relied upon. For this reason:
  - the back-up generation planned for 2019 may be deferred, but cannot be avoided by Option 1. The back-up generation planned for 2034 will also be required by Option 1;
  - the replacement of the cable in any scenario will remove a requirement for voltage support in 2031; and
  - by changing these assumptions in the model, we calculate the capex avoided provides up to a $6.41m NPV benefit to Option 1 (allowing for a deferral of back-up generation for five years).
- SA Power Networks assumes that cable replacement capex is $28.41m in 2018, $15.89m in 2019 and $0.06m in 2020. SA Power Networks[28] has placed heavy emphasis on cable costs being paid up-front at the time of order placement. Delivery is two years from cable order placement to commercial operation. Therefore, we would expect to see, but did not see, progress payments substantially completed prior to operation of the replacement cable. This implies that the payment schedule is deferred. Applying the same approach to Options 2 and 3, if the payment is made in the year prior to commercial operation, the NPV benefit to Option 1 is $3.66m.[29]
- Model 3 accrues any capex expenditure to calculate an O&M maintenance charge and a depreciated residual value for NPV calculation. The approach used in the model does not write-off or isolate the capex related to the repair of the cable in this calculation. Consequently, this expenditure contributes to an apparent (though unrealistic) increased operation and maintenance costs (increasing the NPV of the cost assessed) and to an increase to the residual value deducted (decreasing the NPV of the cost assessed). The model cannot be corrected for this without significant modification.

103. We estimate that these changes to the base model assumptions increase the NPV of Option 1 to $62.54m. Refer to Table 2 below.

[28] SAPN and AER phone conference 19 March 2015. Cable purchase orders require upfront payment commitment which includes cable production, specialist shipping transport and cable laying.

[29] This is an estimate based on staged $47.5m * (1+discount rate)^{years}. The Model 3 O&M impact is excluded by this approach. The model requires substantial change to consider cash flows prior to the assessed period.

Table 2: Adjusted SA Power Networks' NPV assessment of Option 1, 2 and 3 ($m)

Option	Description	Capital	O&M	Generation	VCR	Losses	Total
Option 1	Cable replacement in 2018	$53.85	$8.69	$0	$0	$0	$62.54
Option 2	Run to failure	$42.10	$7.89	$24.10	$1.49	$0	$75.59
Option 3	Run to failure with quick response	$44.87	$8.52	$8.64	$0.32	$0	$62.34

Source: EMCa analysis

104. As shown in Table 2, having adjusted the Option 1 NPV, we now find that Option 3 ($62.34m) offers a marginal NPV benefit. However, it is our view that this result provides insufficient evidence to support a run to failure scenario. It places unnecessary reliance on a long-tailed probability assumption. It also fails to assess the profile and risk of early failure that will influence the investment in mitigation and the impact on any cost savings. This is best tested by comparing Option 1 with deferred cable replacement scenarios over a shorter period of analysis.

105. SA Power Networks has not provided supporting cable condition assessment or technical evidence that supports the failure probability density function for the remaining economic life of the cable. Nevertheless, we consider that the normal probability function, in the absence of better information, is reasonable for assessment of this type of cable failure.

106. We have not used '*Model 3 - Kangaroo Island RIT-D Evaluation 30 years*' further in this assessment. A separate incremental analysis was developed to assess the alternative deferral scenarios. Model 3's O&M and residual value calculation methodology was found to be unsuitable for comparing deferral options over the shorter period of analysis. The approach used in the model does not write-off or isolate the capex related to the repair of the cable. This calculation introduces variations over a much longer period of assessment. The results and sensitivity assessments using Model 3 were found to be similar, but not easily comparable.

3.4.3 Other considerations

Adequate consideration of non-network solutions

107. SA Power Networks advises that the current generation capacity is restricted in its capability to provide continuous electricity supply. However, we did not find evidence of adequate consideration of alternate forms of generation capacity to meet the load on Kangaroo Island. Further, we did not find adequate consideration of the impact of 'disruptive technologies' (as seen in other electricity distribution networks in Australia) including analysis of solutions such as solar PV, wind generation, demand response and energy storage.

108. It is our experience that alternative forms of generation, coupled with demand side management methods, can potentially provide effective and viable supply solutions for areas such as Kangaroo Island. Such solutions could also be integrated with an earlier re-powering of the Kingscote power station to provide alternative cable replacement options. Whilst we have not been requested to review other options, or alternate solutions in our assessment, we consider that the absence of adequate consideration of these solutions may bias the analysis towards installing a second subsea cable. All scenarios that serve to defer the replacement of this cable will preserve options (including innovative

technologies) to utilise such alternatives and to reduce the risk of building what may turn out to be an unnecessary and expensive asset.

Impact to network security

109. SA Power Networks advises that the consideration of this project is to ensure security of the electricity supply to Kangaroo Island, and to mitigate the economic impact from loss of supply due to a failure of the current subsea cable. Once the second subsea cable is installed, the supply to Kangaroo Island will have N-1 redundancy in the event of a single cable failure. However, this redundancy is removed once the first cable is no longer serviceable and a single cable once again supplies electricity from the mainland. We did not observe consideration of supply security once the existing cable is no longer serviceable and note that similar supply risks will then apply for the new subsea cable.

Management of risk of cable failure

110. SA Power Networks has developed an emergency management plan that considers the back-up generation requirements of the Island in the event of a cable failure and loss of supply from the mainland. We did not observe consideration of risk mitigation for events that, as described by SA Power Networks, could contribute to the failure of the cable such as third party damage. Such actions, if feasible and where material, would affect the probability-weighted outcome in the NPV analyses.

Commissioning of the subsea cable

111. In its Asset Management Plan, SA Power Networks states that following the repair of a deep ocean fault: "*Generation will be required to operate for at least 12 months until SA Power Networks is satisfied with the cable's integrity*."[30] We consider that this reflects a very conservative management approach, and assumes incurring additional expenditure without assessment of the risks or benefits.

3.5 Modelling, sensitivity and assumptions

3.5.1 Key model assumptions

Voltage support

112. A new 33kV Voltage Regulator Station is proposed in 2030 to provide voltage support on the 33kV line between Penneshaw and American River ($3.9M). SA Power Networks suggests that this cost can be avoided if the cable is replaced. However, the rationale for this scenario is not adequately explained as the cable is proposed to be initially operated at 33kV and, based on the demand forecast, would operate within the existing cable rating. Therefore, the network would be expected to exhibit similar voltage support issues. Alternatively, if SA Power Networks assumes that the cable will operate at 66kV, it would be

[30] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03) page 20

reasonable to assume that voltage support would not be required if the remainder of the connections were upgraded.

113. Under all scenarios, the cable will be replaced by 2030 and the cost voltage support therefore avoided. For the purposes of our comparative analysis, we have assumed that the voltage support expenditure is no longer required to be included in the analysis.

Back up generation

114. SA Power Networks made no provision for back-up generation in Option 1 on the basis that the original cable continues to be available when the new cable is installed. We have assumed, in our analysis, that the back-up generation planned for 2019 may be deferred, but cannot be avoided by Option 1. Similarly, the requirements for back-up generation planned for 2034 will be the same for Option 1 as for other options.

VCR assumptions

115. SA Power Networks advises that: *"in an event of a cable failure, Kangaroo Island will experience poor 33kV sub-transmission reliability of supply similar to the period prior to 2006 which represents an additional 11.5 hours of interrupted supply."*[31] The VCR cost assumption, based on one year of generation with the average Kangaroo Island load at 3.8MW, is estimated to be $3.4m.

116. We note that the VCR assumptions in Model 3 are lower than prior models provided. These changes are not material to our assessment. The case for cable replacement using a $3.4m VCR assumption would be improved by approximately $250k by reducing the benefit of the best case alternative.

Time for repair and cost

117. SA Power Networks assumes that the time for repair is 12 months (without mitigation) and 4 months (with a $5.9m cable length pre-purchase, storage and access road mitigation strategy). It is reasonable to suggest that the fast response mitigation strategy is needed both now and post-installation of the replacement cable. We have not questioned the availability of alternative storage or the need for an access road at some time in the future (and hence an avoided cost).

Time for Cable replacement

118. The time for replacement is assumed to be two years in all scenarios.

119. The most important impact of this assumption is the timing of the cable replacement capex. As discussed above, there is an inconsistency in SA Power Networks' assumptions for the timing of the Option 1 capex and commercial operation of the replacement cable. The replacement cost for Option 1 is also in two stages; in all other options, the cost is a single expenditure in the second year prior to operation. Our incremental assessment

[31] SAPN - 20.38 PUBLIC - SAPN Kangaroo Island (AMP 2.1.03) page 13

has applied the same principle to all options with expenditure in the second year prior to operation of the replacement cable.

3.5.2 Other matters

Probability of failure

120. SA Power Networks has proposed a normal distribution based on the standard deviation of the square root of the expected life to formulate the probability of failure of the KI cable. SA Power Networks has not provided supporting cable condition assessment or technical evidence that supports the failure probability density function for the remaining economic life of the cable.

121. The normal distribution is characterised by an increasing conditional probability of failure appropriate to failure risks (such as wear and age). It is consistent with a scheduled replacement asset strategy at a targeted economic life. It is a reasonable basis for assessing the timing of early replacement. SA Power Networks has correctly adjusted the probability distribution function for the assessment period, assuming no prior failure.

Fuel Costs

122. Fuel cost is a major component of the assessment.[32] This is driven by the efficiency of installed generators and delivered costs of fuel oil. The assumed fuel cost for SA Power Networks' modelling of [redacted]/MWh is higher than expected. Fuel costs are [redacted]/litre before deduction of a fuel excise rebate of $0.316/litre (net [redacted]/litre). This equates to a fuel usage of [redacted] litres/MWh.

123. SA Power Networks 12 month's fuel calculation[33] indicates an average fuel rate for Kingscote power station of around [redacted] litres/MWh (and less for mobile generation). At [redacted]/litre this equates to [redacted]/MWhr, which is substantially less than the [redacted]/MWh figure that SA Power networks has assumed.

124. We note that SA Power Networks' $31.8m cost estimate for 12 months generation includes the variable cost fuel component of $20.6m. The variable fuel component includes a 25% contingency, is based on a higher level of generation (4.0MW) and has not included the fuel excise rebate (separately treated as a fixed cost deduction). This may explain why the marginal cost of generation used in Model 3 is higher than expected (an increased cost estimate on the same generation assumption). As Model 3 scales the total cost to $31.8m, the impact is limited to the variations in generation around the assumed average load. On the other hand, the total $31.8m cost, being inflated by a 25% contingency, suggests the potential for a lower actual generation cost by this same amount. A similar conclusion is made on the four month generation cost. The impact of a lower generation cost is tested later in this assessment.

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[32] SA Power Networks incur the total cost of generation as a back-up supply without any market options for supply.

[33] [redacted]

125. SA Power Networks indicated that fuel oil is delivered by mainland tankers to be run-on and run-off the ship. Other than the direct cost of transport to the island, this suggests SA Power Networks is capable of seeking bulk supply of fuel oil at competitive rates. We have not examined whether SA Power Networks could negotiate a better bulk fuel rate than [redacted]/litre (pre-excise fuel rebate).

3.5.3 Deferral Scenarios for Cable Replacement

126. As noted above, we have not used *Model 3 - Kangaroo Island RIT-D Evaluation 30 years* further in this assessment. We developed a separate incremental analysis to assess the alternative deferral scenarios. Model 3's O&M and residual value calculation methodology was found unsuitable and could not be easily modified for comparing the deferral options over the shorter period of analysis. The results using both approaches were comparable, but any variation in results could not be easily reconciled using the RIT-D model.

127. The upfront cost of accelerated repair may not present the same benefits in shorter assessment periods. We have therefore examined alternative deferral scenarios of two years and five years to examine the benefits of planned replacement and the risks of early failure as described in Table 3 below.

Table 3: Summary of Option 1 preferred scenario variants

SA Power Networks proposal and alternative options		EMCa analysis				
		Strategy	Repair time	Install time	Deferral	Operational year
Option 1	Preferred option. New cable 2017/18, operational 1 July 2018	New subsea cable (base case)	n/a	2 years	none	2018
Option 1A	Two Year Deferral. Operation 1 July 2020	Slow Repar	1 Year	2 years	2	2020
		Fast Repair	4 months	2 years	2	2020
Option 1B	5 Year Deferral. Operational 1 July 2023	Slow Repair	1 Year	2 years	5	2023
		Fast Repair	4 months	2 years	5	2023

Source: EMCa analysis

128. In each case, the assessment calculates the net present value for replacement after cable failure, aggregating the costs of prior failure.

129. The incremental analysis used in this assessment is provided in Appendix B. The model includes the cost assumptions provided by SA Power Networks. While the assessment remains dependent on SA Power Networks' probability density function, it does not rely on the long-tailed probability distribution for the latter years. The assessment is limited to a five year time horizon. All expenditure after the period of assessment is the same once the cable is replaced. The preferred Option 1 (cable replacement in 2018/19) base cost is

recalculated for this analysis and is therefore different to the previous Model 3 assessment.

Scenario 1: Two-year project deferral - (Options 1A - slow and fast repair)

130. SA Power Networks' Option 1 assumes that the cable is replaced and in operation by 1 July 2018. This exposes any alternative scenario, relying on the existing cable, to the risk of failure for the period until the cable is replaced.

131. A two year deferral of the cable replacement (Option 1A) will assume the cable is operational on 1 July 2020. The purpose of this scenario is to test the latest time to deliver the cable in the forthcoming RCP (i.e., the cable is paid for and delivered by 1 July 2020).

132. The slow repair and fast repair mitigation scenarios will be exposed to generation and VCR costs of cable failure from 1 July 2018 (2018/19 period) to 1 July 2020. The comparison to SA Power Networks' preferred Option 1 scenario will assess the impact of two years generation and VCR costs, the cost of repair (year 1) and replacement of cable of the cable by 2020 (year 2).

133. With the cable replaced and operational by July 2020, the post replacement costs assumed in Option 1 will be the same. The cable is assumed to provide standby capacity for Option 1 only up to 2023.

134. As shown in Table 4 below, a two year deferral will not deliver a NPV benefit for either the 4 month (fast repair) or the 12 month (slow repair) repair strategies. The fast repair strategy requires an upfront investment of $5.9m for repair cable purchase, storage and a new weather safe track at Cuttlefish Bay. This outlay is not recovered over a two year deferral period.

Scenario 2: Five year Deferral – (Option 1B - slow and fast repair)

135. A five year deferral of the cable replacement (Option 1B) will assume the cable is operational on 1 July 2023. The purpose of this scenario is to test the delivery of the cable after the forthcoming RCP (i.e., the cable is fully paid for and delivered after 1 July 2020).

136. The slow and fast mitigation scenarios will be exposed to generation and VCR costs of cable failure from 1 July 2018 (2018/19 period) to 1 July 2023. The comparison to SA Power Networks' preferred Option 1 scenario will assess the impact of five years' generation and VCR costs, the cost of repair (years 1 to 4) and replacement of the cable by 1 July 2023 (year 5).

137. With the cable replaced and operational by 1 July 2023, the post replacement costs assumed in Option 1 will be the same thereafter. A two and five year deferral will not deliver an NPV benefit. We conclude that the cost of the fast cable repair is not recoverable over the deferral period.

138. A summary of the NPV associated with each of these options is provided in Table 4 below.

Table 4: Summary of NPV for alternative options assessed[34]

Option	Deferral	Repair	Operational year	Expected value
Option 1	nil	nil	2018	$ 53.60
Option 1A	2 years	slow	2020	$ 55.12
		fast	2020	$ 57.13
Option 1B	5 years	slow	2023	$ 60.12
		fast	2023	$ 55.84

Source: EMCa analysis

Sensitivity to cost of fuel

139. We tested the sensitivity of fuel costs by assuming a fuel rate of [redacted] litres/MWh for Kingscote Power Station fuel and a diesel cost (net of the fuel excise rebate) of [redacted]/litre (which when multiplied together calculates a fuel rate of [redacted]/MWh).[35] Using the fixed costs assumptions in Model 3 for generation related mobilisation and maintenance, a fuel cost of [redacted]/MWhr would reduce total generation costs by approximately 25% (equivalent to SA Power Networks contingency allowance). The impact on the deferral scenarios is shown in Table 5 below. A discount on total fuel costs of 30% or more would convert the two year deferral scenario from marginal to positive.

Table 5: Fuel Cost impact on deferral scenarios

Option	Deferral	Repair	Operational year	Expected value
Option 1	nil	nil	2018	$53.60
Option 1A	2 years	slow	2020	$53.86
		fast	2020	$56.68
Option 1B	5 years	slow	2023	$57.00
		fast	2023	$54.72

Source: EMCa analysis

3.6 Summary

140. We have assessed the SA Power Networks methodology (Models 1, 2 and 3) for assessment of the optimum time for replacement and found these to be incomplete for use in justifying the efficient timing of the expenditure.

141. The methodology did not address the probability, consequences and combined outcome if the cable failed or did not fail. The Model 3 Options provided no prudent alternatives to the preferred cable replacement scenario.

142. SA Power Networks' application of the probability of failure into the NPV analysis (Models 1, 2 and 3) was found to be inconsistent. The AER and SA

[34] A separate incremental analysis was developed to assess the alternative deferral scenarios. The O&M and residual value calculation methodology of Model 3 was found unsuitable for comparing the deferral options over the shorter 5 year period of analysis. The results using both approaches were comparable, but any variation in result could not be easily reconciled using the RIT-D model.

[35] [redacted]

Power Networks' partial analysis (Models 1 and 2) and the three options selected for full assessment (Models 3) were not comparable in terms of assumptions, costs and timing.

143. The AER and SA Power Networks' spreadsheet analysis (Models 1 and 2) is incomplete and, in our view, is inadequate to assess the optimum timing of cable replacement. The partial analysis hinted at a preferable timing, but could not provide a definitive assessment without inclusion of the full cost/consequences of each outcome.

144. We determined that the SA Power Networks' Model 3 RIT-D analysis, as provided, was unable to deliver a more competitive cost comparison for cable replacement for the following reasons:

- the capex assumptions were inconsistent in each option if the cable failed and was replaced, or it continued to be operational. Options 2 and 3 did not avoid any costs (in part or in full) for voltage support once the cable failed and was replaced. Option 1 assumed the original cable continued to deliver back-up supply (and defer back up generation for the whole period of assessment). Option 1 also received the benefits of voltage support at 33kV without expenditure for upgrade to 66kV;
- the timing and capital expenditure for the replacement of the cable was favourable to Option 1. All of the expenditure (stages 1, 2 and 3) for cable replacement in Option 1 was incurred after the cable was commissioned and in commercial operation. By comparison, Option 2 and 3 was modelled to include the expenditure for two years of generation and the replacement of the cable before the full expenditure had been incurred for the cable replacement in Option 1;
- the assumptions for fuel costs of [redacted]/MWh require review. The Kingscote Power Station (6.0MW) generators fuel usage at average load is [redacted] litres/MWh. SA Power Networks has identified fuel costs of [redacted]/litre which would indicate a model assumption fuel usage of [redacted] litres/MWh. The high fuel usage rate appears to be related to a 25% contingency allowance and the calculation of generation fuel costs; and
- Model 3 accrues any capital expenditure to calculate an O&M maintenance charge and a depreciated residual value for NPV calculation. The approach used in the model does not write-off or isolate the capex related to the repair of the cable in this calculation. Consequently, this expenditure may contribute to an increased operation and maintenance costs (increasing the NPV assessed) and an increase to the residual value deducted (decreasing the NPV assessed). The methodology was found to be suitable for comparing the deferral options over the shorter five year period of analysis.

145. We have therefore relied on an incremental assessment to assess a base cost and the cost of deferral. Our assessment includes:

- adjustment of the Option 1 base cost for the recommended capex changes and capex timing;
- assessment of deferral of the cable replacement by two years (Option 1A) and five years (Option 1B);

- each option was assessed on the risks of failure, costs of repair and replacement for a slow repair and a fast repair scenario. This was then compared to the Option 1 base cost; and
- an assumption that no failure occurs prior to the cable replacement in Option 1.

146. We note that the fuel cost is a major component of the assessment. We tested the sensitivity of the analysis and consider that a 25% reduction in fuel cost did not change the assessment.

147. While the changes to the assessment make cable replacement less compelling, our assessment leads us to support replacement of the cable prior to the end of its economic life. Our assessment leads us to support the timing proposed by SA Power networks and does not lead us to support deferral of the cable replacement by two years or five years.

Appendix A Documents reviewed

148. In providing advice to the AER, we reviewed a number of documents specific to the business case review, listed in the table below.

Table 6: Documents considered

Document Title
SAPN Regulatory Proposal 2015-2020
SAPN – 20.38 PUBLIC – SAPN Kangaroo Island (AMP 2.1.03)
AER SAPN 037-Kangaroo Island risk adjusted FINAL response
AER SAPN 037_CONFID Attach 3 KI RIT-D Evaluation
AER SAPN 037_CONFID Attachment 1
AER SAPN 037_CONFID Attachment 2
AER SAPN 037_CONFID Attachment 3
AER SAPN 037_CONFID Attachment 4
AER SAPN 037_Attachment 5
AER SAPN 037-PUBLIC_Attachment 4
[redacted]

Appendix B Supporting analysis

149. We have included a copy of the analysis that we have relied upon in our assessment and findings below.

Capex adjustment to Option 1

150. The back- up generation planned for 2018 may be deferred but cannot be avoided by Option 1. An adjustment is made to defer 2018 back-up generation by five years. The back-up generation planned for 2034 will also be required by Option 1.

151. The replacement of the cable in any scenario will remove a requirement for voltage support in 2031. As shown in Table 7 below, the total capex avoided provides up to a $6.4m NPV benefit to Option 1.

Table 7: Capex adjustment to Option 1 - back-up generation and voltage *support*

Option	Description	Capital	O&M	Generation	VCR	Losses	Total
Option 1	Cable replacement in 2018	$43.78	$8.69	$0	$0	$0	$52.47
Option 2	Run to failure	$42.10	$7.89	$24.10	$1.49	$0	$75.59
Option 3	Run to failure with quick response	$44.87	$8.52	$8.64	$0.32	$0	$62.34
EMCa option 1	Option 1 incl capex	$49.26	$9.61	$0.00	$0.00	$0	$58.87

Source: EMCa analysis of attach 3 KI RIT-D Evaluation 30 years Rev2 v1.0 (RW) v5.1 capex

Capex timing of cable replacement

152. The timing and capital expenditure for the replacement of the cable was favourable to Option 1. All of the expenditure (stages 1, 2 and 3) for cable replacement in Option 1 was paid after the model assumed that it was commissioned and in commercial operation, as shown in Table 8. By comparison, Option 2 and Option 3 were modelled to pay for two years loss of generation and the replacement of the cable before Option 1 had incurred all of the expenditure.

Table 8: Option 1 cable replacement payment profile

Year	Description		
2018	Cable replacement stage 1	$28.41	$1.05
2019	Cable replacement stage 2	$15.89	$2.10
2020	Cable replacement (project finalised and closed)	$0.06	

Source: EMCa analysis

153. Applying the same approach as Option 2 and Option 3, if the payment is made in the year prior to commercial operation, the NPV benefit to Option 1 is $3.66m. Refer to Figures 2 and 3 below.

Figure 2: Option 2 Generation/VCR costs and cable repair capex profile

Generation Operating Costs

Period	Year	Average Load (MW)	Days Operation	MWH Generated	Cost MWh	Cost Time	Risk (Cable Failure Rates)	Risk Adjusted Generation Costs ($k)	Other costs ($k)	Repair costs ($k)	Replacement Cost ($k)	Risk adjusted Capital Cost ($k)	Generator Failure Hours	VCR Cost based on Kingscote Gen ($k)
1	2018	3.8	365	33,288	19,600	11,053	7.7%	2,461		$ 11,400		881	6	$ 68
2	2019	3.8	365	33,588	19,776	11,053	8.5%	2,734		$ 11,400	47500	4,647	6	$ 76
3	2020	3.9	365	33,890	19,954	11,053	9.1%	2,938		$ 11,400	47500	5,099	6	$ 82

Source: EMCa analysis

Figure 3: NPV benefit of cable payment schedule

		SUM	NPV	DIFFERENCE
2017	Cable payment	$47,500.00	$43,844.95	$3,655.05
2018	$28,405.00	$1,050.00	$29,455.00	cable in-service
2019	$15,890.00	$2,100.00	$17,990.00	
2020	$55.00		$55.00	

Source: Attach 3 KI RIT-D Evaluation 30 years Rev2 v1.0 (RW) v5.1 capex

154. With these changes to the base model assumptions, the NPV of Option 1 would be increased to $62.54m. Having adjusted the Option 1 NPV, we now find Option 3 ($62.34m) offers a marginal NPV benefit. However, we consider this to provide insufficient evidence to support a run to failure scenario.

Summary of two-year and five-year deferral options

155. We have not used Model 3 - Kangaroo Island RIT-D Evaluation 30 years further in this assessment. A separate incremental analysis was developed to assess the alternative deferral scenarios. Model 3's O&M and residual value calculation methodology was unsuitable for the deferral option analysis. The following figures below have been extracted from the incremental NPV analysis undertaken.

Figure 4: Base Case 2 year and 5 year Deferral (slow)

NPV cost of waiting until the cable fails using normal probability distribution	NPV ($m)	2018-19	2019-20	2020-21	2021-22	2022-23
Probability of KI Cable failure using normal distribution commencing in 2015-16 and 100% chance of failure by 2039-40.		7.7%	8.5%	9.1%	9.4%	9.4%
SLOW						
Examines the probability weighted cost impact of deferring installing the second cable beyond 2018/19						
Option 1 Replace cable 17/18 operational 18/19	$53.60	$50.35	$0.00	$0.00	$0.00	$4.10
Install second cable in 19/20 (incl risk of failure)	$54.97	$51.10	$4.10			
Install second cable in 20/21 (incl risk of failure)	$55.12	$3.60	$54.61			
Install second cable in 21/22 (incl risk of failure)	$56.56	$3.60	$11.75	$47.04		
Install second cable in 22/23 (incl risk of failure)	$58.27	$3.60	$11.75	$8.31	$43.09	
Install second cable in 23/24 (incl risk of failure)	$60.12	$3.60	$11.75	$8.31	$8.74	$38.75

Source: EMCa analysis

Figure 5: Base Case, 2 year and 5 year Deferral (fast)

NPV cost of waiting until the cable fails using normal probability distribution	NPV ($m)	2018-19	2019-20	2020-21	2021-22	2022-23
Probability of KI Cable failure using normal distribution commencing in 2015-16 and 100% chance of failure by 2039-40.		7.7%	8.5%	9.1%	9.4%	9.4%
FAST						
Option 1 Replace cable 17/18 operational 18/19	$53.60	$50.35	$0.00	$0.00	$0.00	$4.10
Install second cable in 19/20 (incl risk of failure)	$54.97	$51.10	$4.10			
Install second cable in 20/21 (incl risk of failure)	$57.13	$7.44	$52.67			
Install second cable in 21/22 (incl risk of failure)	$56.41	$7.44	$9.48	$44.97		
Install second cable in 22/23 (incl risk of failure)	$56.00	$7.44	$9.48	$5.88	$40.95	
Install second cable in 23/24 (incl risk of failure)	$55.84	$7.44	$9.48	$5.88	$6.22	$36.62

Source: EMCa analysis

156. The summary of the options analysis has also been reproduced in Figure 6 below.

Figure 6: Summary of EMCa analysis

Option	Deferral	Repair	Operational year	Expected value
Option 1	nil	nil	2018	$ 53.60
Option 1A	2 years	slow	2020	$ 55.12
		fast	2020	$ 57.13
Option 1B	5 years	slow	2023	$ 60.12
		fast	2023	$ 55.84

Source: EMCa analysis