Draft Project Assessment Report (DPAR)

Kangaroo Island Submarine Cable

2 November 2016

SA Power Networks
www.sapowernetworks.com.au

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This Draft Project Assessment Report (DPAR) has been prepared in accordance with and is limited to the requirements of Clause 5.17.4 of the National Electricity Rules for the purpose of publicly announcing the provisional outcome of SA Power Networks evaluation of options in response to a specific set of identified needs. The DPAR is a summary or general description only of the matters considered by SA Power Networks when evaluating the various options. It is not intended to be used for other purposes, such as making decisions to invest in generation, transmission or distribution capacity.

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Version Control

Version	Author	Date	Reviewer	Date	Approver	Date
1	Andrew Lim (Substation and Planning Engineer)	25/10/2016	David Pritchard (Manager Network Planning)	27/10/2016	Doug Schmidt (General Manager Network Management)	2/11/2016

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1. Report Summary

Kangaroo Island is the third largest island off the coast of Australia, situated in the Southern Ocean approximately 15 kilometres off the tip of the Fleurieu Peninsula, across the waters of Backstairs Passage. Kangaroo Island is supplied via a radial (single path) sub-transmission network consisting of approximately 50km of 66kV line between Willunga and Cape Jervis and 90km of 33kV line between Cape Jervis and Kingscote, with a 15km section of 33kV submarine cable installed between Fishery Beach on the mainland and Cuttlefish Bay on Kangaroo Island.

In compliance with SA Power Networks distribution license, we are obligated to use best endeavours to achieve reliability targets[1] for each year ending 30 June. In part those targets are achieved by operating the network standby generators near Kingscote on KI, when there are failures of the radial supply to Kangaroo Island. SA Power Networks has identified that when the 33kV submarine cable fails, the standby generators would operate for up to 12 months to maintain supply to customers on Kangaroo Island, at a cost of up to $25.4 million, whilst the cable is repaired[2]. In addition, the backup generators are less reliable than the grid supply and consequently if the generators are operated for a long period then it will impact on tourism, business, community and the economic development of Kangaroo Island

As the submarine cable is nearing the end of its design life, as such the risk of a failure is increasing every year, SA Power Networks considered it prudent to determine if the cost was lower to replace the cable in the near future or to run to failure.

SA Power Networks has identified a potential credible network option to address the identified network security constraint by Installing a new submarine cable from Fishery Beach to Cuttlefish Bay in 2018. SA Power Networks has sought firm offers for the supply and installation of a new cable in parallel with performance of the Regulatory Investment Test – Distribution (RIT-D) process.

As required by the National Electricity Rules (NER), SA Power Networks plans to complete a formal Regulatory Investment Test – Distribution (RIT-D) prior to committing to the investment solution to the identified security constraint. In April 2016, SA Power Networks commenced the formal RIT-D consultation process by publishing the Non-Network Options Report (NNOR), seeking submissions from non-network providers on potential credible options to address the identified security constraint. A question and answer session was then held at SA Power Networks office on 16th May 2016 to assist any interested parties in preparing their non-network submissions.

In response to this consultation, SA Power Networks received eight external proposals by the NNOR closing date of 15th July 2016 to address the network security constraint. Of the initial eight submissions, SA Power Networks has short listed three submissions deemed to be credible and compliant in that they resolve the identified network constraints either individually or when combined with other augmentations, within the timeframes specified within the NNOR.

1 The targets are detailed in the South Australia Electricity Distribution Code (EDC) clause 2.2.1.

2 A repair may not be possible depending on where the fault occurs and what condition the cable is in when recovered from the sea bed.

The network and non-network options considered as part of the RIT-D evaluation are as follows:

- Option 1 Install new submarine cable from Fishery Beach to Cuttlefish Bay in 2018.
- Option 2 Run the existing cable to failure, repair and install a new submarine cable post failure of the existing cable.
- Option 3 Run the existing cable to failure but provide the capital and operating expenditure including additional spare cable to reduce the time to repair the cable.
- Option 4 Run the existing cable to failure with pre-purchase of submarine cable to reduce the cable replacement time.
- Option 5 A non-network solution consisting of biomass, solar and diesel generation as proposed by Applicant 1.
- Option 6 A non-network hybrid solution consisting of wind, solar and diesel generation combined with short-term battery storage as proposed by Applicant 2.
- Option 7 A non-network generation solution consisting of solar and diesel as proposed by Applicant 3 with a turn-key solution for the design, supply, delivery, installation and commissioning of a 10MVA submarine cable when the existing submarine cable fails.

SA Power Networks preferred and recommended solution is to install a new submarine cable from Fishery Beach to Cuttlefish Bay in 2018 (Option 1). The option analysis in this report clearly demonstrates that installing a new submarine cable from Fishery Beach to Cuttlefish Bay in 2018 is the most preferred option by providing the highest net market benefit or lowest economic cost under all scenarios considered. The total project cost of this recommended option is estimated to be $25.6 million in present value terms[3].

Submissions in response to this Draft Project Assessment Report (DPAR) are due on or before Wednesday, 14th December 2016.

An electronic copy of this report is available at

http://www.sapowernetworks.com.au/centric/industry/our_network/annual_network_plans/draft_project_assessment_reports.jsp

[3] The $25.6M cost is based on a competitive tender process and it excludes corporate business overheads, contingencies and preliminary project costs whereas the initial $45M estimate of the NNOR was based on the total project cost using high level budget estimates from suppliers. Further savings were achieved by modifying the technical specification of the submarine cable to reflect the future forecast requirements on Kangaroo Island.

2. Introduction

2.1 Introduction

SA Power Networks is South Australia's principal Distribution Network Service Provider (DNSP) and is responsible for the distribution of electricity to all distribution grid connected customers within the State. We are a corporate partnership comprising CKI Utilities Development Limited, PAI Utilities Development Limited, Spark Infrastructure (No.1) Pty Ltd, Spark Infrastructure (No.2) Pty Ltd and Spark Infrastructure (No.3) Pty Ltd. More information about us can be obtained from our website at:

http://www.sapowernetworks.com.au

Under the National Electricity Rules (NER) a project that is in response to a qualifying Identified Need must be subjected to an evaluation process (the Regulatory Investment Test – Distribution or RIT-D) that is described in Clause 5.17 of the NER. All credible options, both network and non-network, are evaluated equally under the test and the preferred option is the one that maximises the economic gain or minimises the economic loss to the electricity market. A credible option is defined as a solution that must by itself or in combination with other non-network solutions or traditional network solutions, demonstrate that it resolves all of the identified network constraints, is of equal network security performance (availability) than the proposed network solution (2nd cable), economically viable (cost effective), be technically feasible in that it is possible that sufficient supply will be provided by the option to meaningfully defer the preferred network option and is achievable within the required timeframe to resolve the identified need. More information about this regulatory process may be obtained from the AER through their website.

http://www.aer.gov.au

Information on how SA Power Networks applies the RIT-D process can be found in our Demand Side Engagement Document available on our website at:

http://www.sapowernetworks.com.au/dsed/index.jsp

This report summarises the evaluation of the proposals received in response to the Non-Network Options Report (NNOR) along with SA Power Networks own network solutions in accordance with the Regulatory Investment Test – Distribution (RIT-D) to address the identified need.

This draft project assessment report provides and complies with the requirements of NER Clause 5.17.4. (j) as described in Section 12 of this document.

2.2 Project History

Table 1: Key dates and milestones

Milestone	Date
Publication of Non-Networks Options Report (NNOR)	Friday, 15th April 2016
Information Session (Q & A)	Monday, 16th May 2016
Final date for Final Proposal Submissions to NNOR	Friday 15th July 2016
Publication of Draft Project Assessment Report (DPAR)	Wednesday, 2nd November 2016
Final date for submissions in response to DPAR	Wednesday, 14th December 2016
Expected date for publication of Final Project Assessment Report (FPAR)	End of December 2016

SA Power Networks will use its reasonable endeavours to maintain the consultation program listed above. However, this program may alter due to changing power system conditions or other circumstances beyond the control of SA Power Networks.

2.3 Contact Details

Submission in response to this Draft Project Assessment Report (DPAR) should be directed to the following e-mail:

requestforproposals@sapowernetworks.com.au

Telephone enquiries can be directed to Pat Howard on (08) 8404 5514 or Andrew Lim on (08) 8404 5410.

Submissions in response to this DPAR are due on or before Wednesday, 14th December 2016. Please refer to Table 1 for more information.

3. Background to Report

3.1 Kangaroo Island Supply Arrangement

Kangaroo Island is the third largest island off the coast of Australia, situated in the Southern Ocean approximately 15 kilometres off the tip of the Fleurieu Peninsula, across the waters of Backstairs Passage.

Kangaroo Island is supplied via a radial (single path) sub-transmission network consisting of approximately 50km of 66kV line between Willunga and Cape Jervis and 90km of 33kV line between Cape Jervis and Kingscote, with a 15km section of 33kV submarine cable installed between Fishery Beach on the main land and Cuttlefish Bay on Kangaroo Island. The Cape Jervis to Kingscote 33kV sub-transmission system consists of six line sections. The Cape Jervis to Kingscote sub-transmission system supplies the 33/11kV zone substations at Penneshaw, American River, MacGillivray and Kingscote as well as 33/19kV SWERs at Island Beach, Baudin Beach, Brown Beach and Nepean Bay.

The existing 33kV submarine cable provides a single connection to the mainland. A catastrophic cable failure is likely to incur substantial costs to repair and maintain supply via SA Power Networks diesel power station at Kingscote over a sustained period (ie up to one year).

The twenty five (25) year evaluation period for this DPAR is driven by the need to obtain the most cost effective development(s) over a reasonable time frame, allowing for uncertainties associated with future network developments, load and generation patterns. Any proposed non-network solution is to be designed for this period with expectations to meet forecast load and any step load changes in customer demand due to major developments on Kangaroo Island.

The area under consideration is shown in Figure 1.

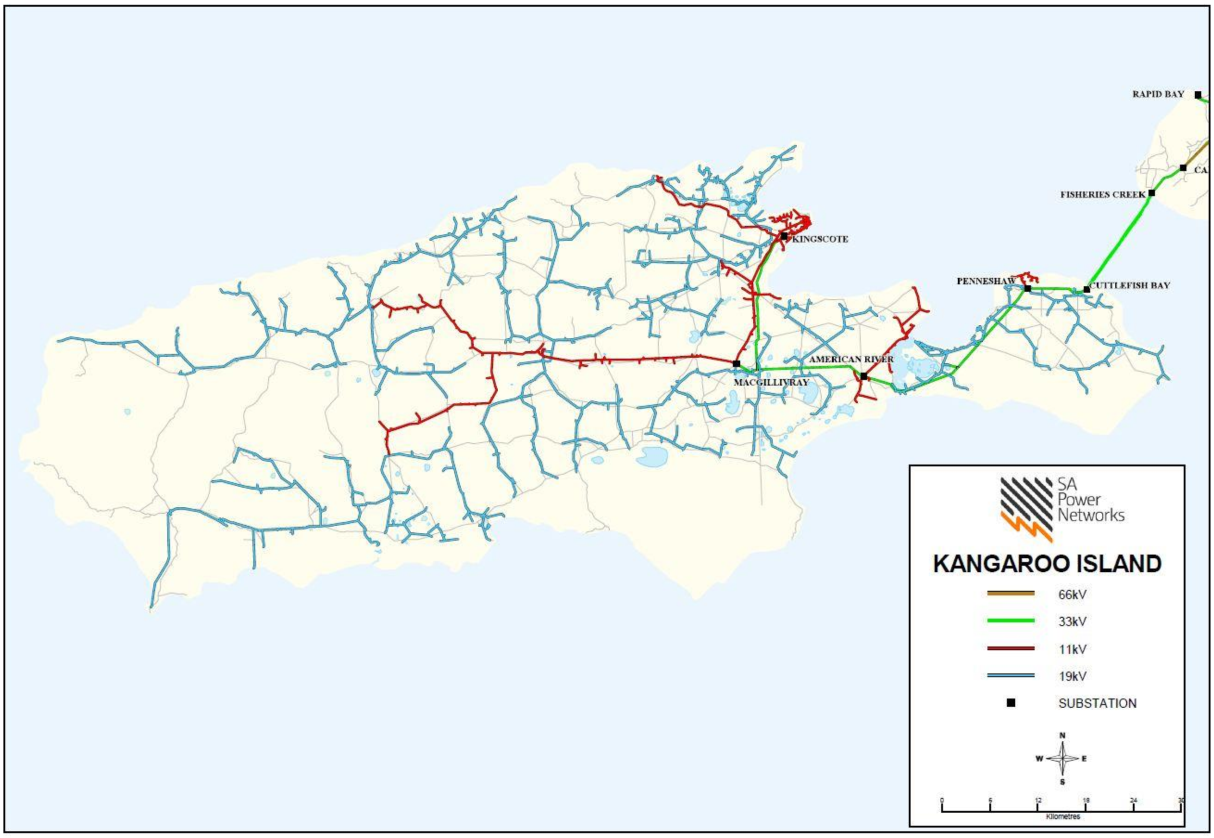

Figure 1: Sub-Transmission Security on Kangaroo Island

3.2 Submarine Cable Background

The existing 33kV submarine cable was installed and first energised in May 1993 with a design life of 30 years. The 50 mm^2 Copper submarine cable has twenty (20) cable joints (approximately every 750m) with a rating of 10MVA at 33kV.

According to the hydrographical survey that was carried out across Backstairs Passage, approximately 2.6km of the cable is laid on the sea bed at a depth of less than 25m (shallow water). The remaining 12km of cable was laid on the sea bed at a depth of more than 25m (deep sea) with a maximum depth of 61.5m. Eighteen (18) of the 20 cable joints in the existing cable (a known common point of cable failure) are located in deep sea, resulting in a high probability of a deep sea cable failure and consequently long repair time. Approximately 13.9km (95%) of the cable originally installed on the sea bed is now completely buried under the sandy sea bed.

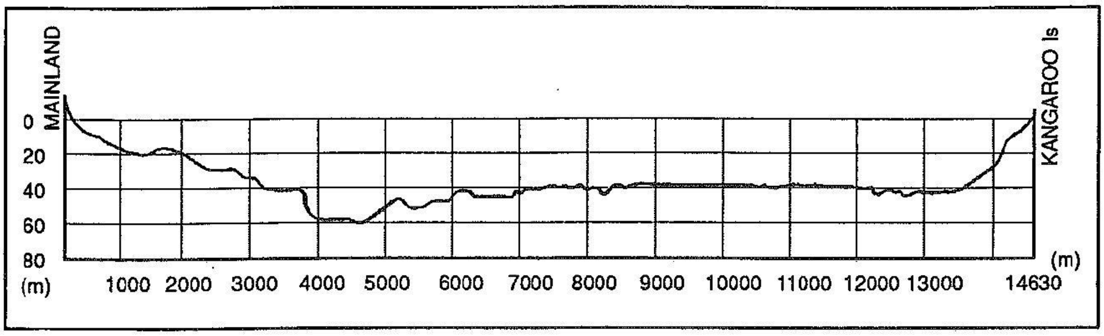

Figure 2: 1991 Hydrographical Survey across Backstairs Passage

3.3 Load Forecasts

The system was assessed for system normal (N) using a 10% Probability of Exceedance (POE) load forecast for Kangaroo Island assuming all equipment is in service on the island.

Table 2 represents the 25-year load forecast for moderate growth on the island (as measured at the mainland) and incorporates diversity between substation loads, sub-transmission losses and an adjustment due to the presence of any embedded generation (including Photovoltaics – PV). Please note that the load forecast contains certain predictions and assumptions that may change from time to time without notice. SA Power Networks accepts no responsibility or liability whatsoever for any reliance that may be placed upon the predictions and assumptions in Table 2 below. Any use of or reliance placed upon such information is at the sole risk of the user.

Year	10% PoE Forecast (MVA)	10% PoE Forecast (MW)	Year	10% PoE Forecast (MVA)	10% PoE Forecast (MW)
2016/17	8.0	7.8	2029/30	10.3	10.0
2017/18	8.1	7.9	2030/31	10.5	10.2
2018/19	8.2	8.0	2031/32	10.7	10.4
2019/20	8.4	8.1	2032/33	10.9	10.6
2020/21	8.5	8.3	2033/34	11.1	10.8
2021/22	8.7	8.5	2034/35	11.4	11.1
2022/23	8.9	8.7	2035/36	11.6	11.3
2023/24	9.1	8.8	2036/37	11.9	11.5
2024/25	9.3	9.0	2037/38	12.1	11.8
2025/26	9.5	9.2	2038/39	12.4	12.1
2026/27	9.7	9.4	2039/40	12.7	12.3
2027/28	9.9	9.6	2040/41	13.0	12.6
2028/29	10.1	9.8			

Table 2: Kangaroo Island Load Forecast

Sensitivity analysis conducted as part of the RIT-D process has considered standard and flat (nil) growth and potential step load changes in customer demand on Kangaroo Island.

3.4 Demand Characteristics

The information and analysis provided in this section is subject to the Disclaimer provided in this Draft Project Assessment Report.

An example of the Kangaroo Island annual load profile (measured from Cape Jervis Substation in MW) is shown in Figure 3. This shows that peak electricity demand on Kangaroo Island occurs during the summer and winter months, predominantly as a result of air-conditioning or hot water load. Non-network solutions must be able to support the annual demand loads under any credible single contingency operating condition (ie supply the peak load with a piece of equipment (eg generator) out of service).

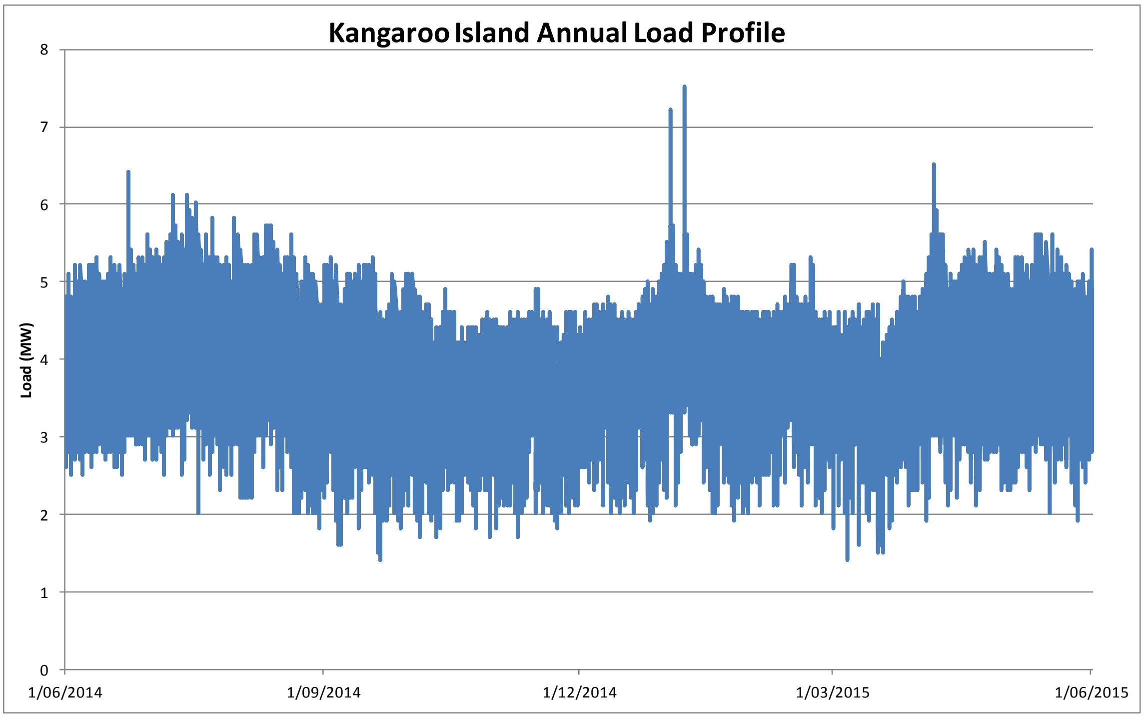

Figure 3: Kangaroo Island Annual Load Profile

The corresponding annual load duration curve (measured from Cape Jervis Substation and including PV impact) is shown in Figure 4. In terms of the annual spread, loads on Kangaroo Island are fairly typical of predominantly residential loads with sharp peaks occurring on a few hot/cold days a year and an average demand for the rest of the time.

The 2014/15 annual electricity consumption on Kangaroo Island was approximately 31GWh with an average daily and hourly consumption of 85MWh and 3.5MWh respectively. Noting that consumption varies, with for example for a week in July, the average daily consumption was approximately 100MWh with an hourly consumption of 4.2MWh. On average, the load is in excess of 95% of the peak for approximately 5 hours per annum and in excess of 85% of peak for approximately 12 hours a year based on a period between June 2014 to June 2015. The average load of 3.5MW is approximately 50% of peak demand.

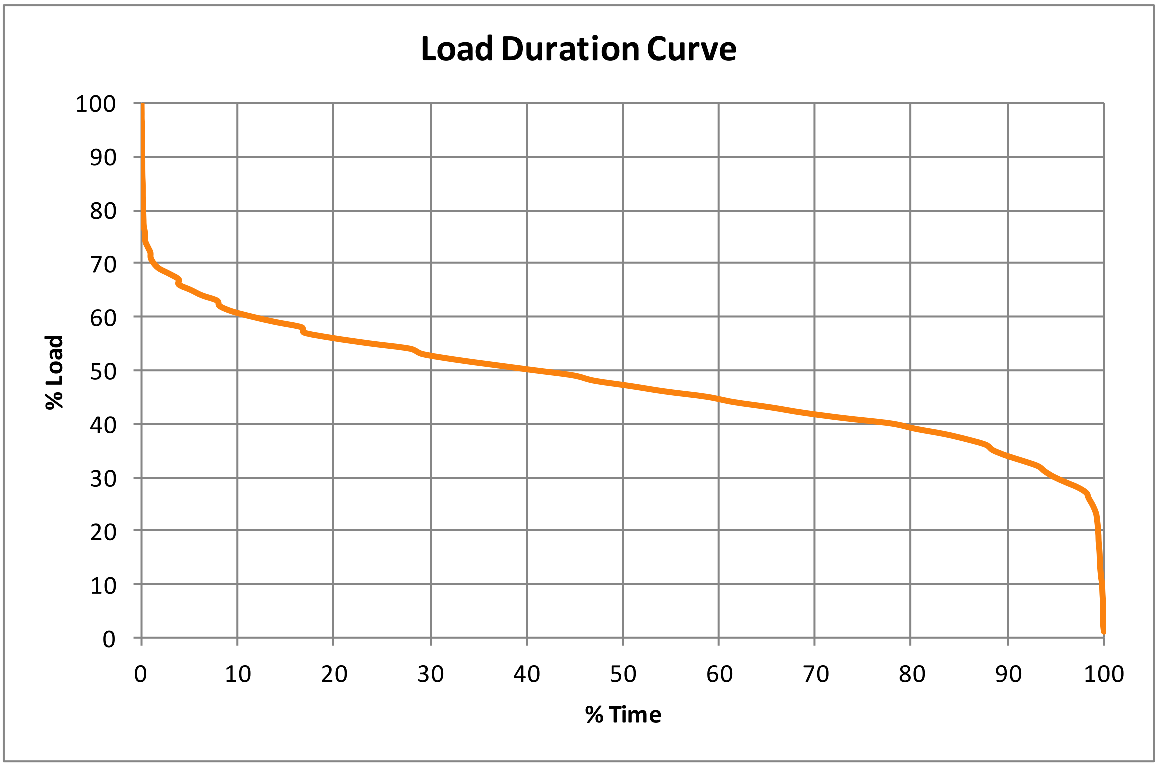

Figure 4: Kangaroo Island Load Duration Curve

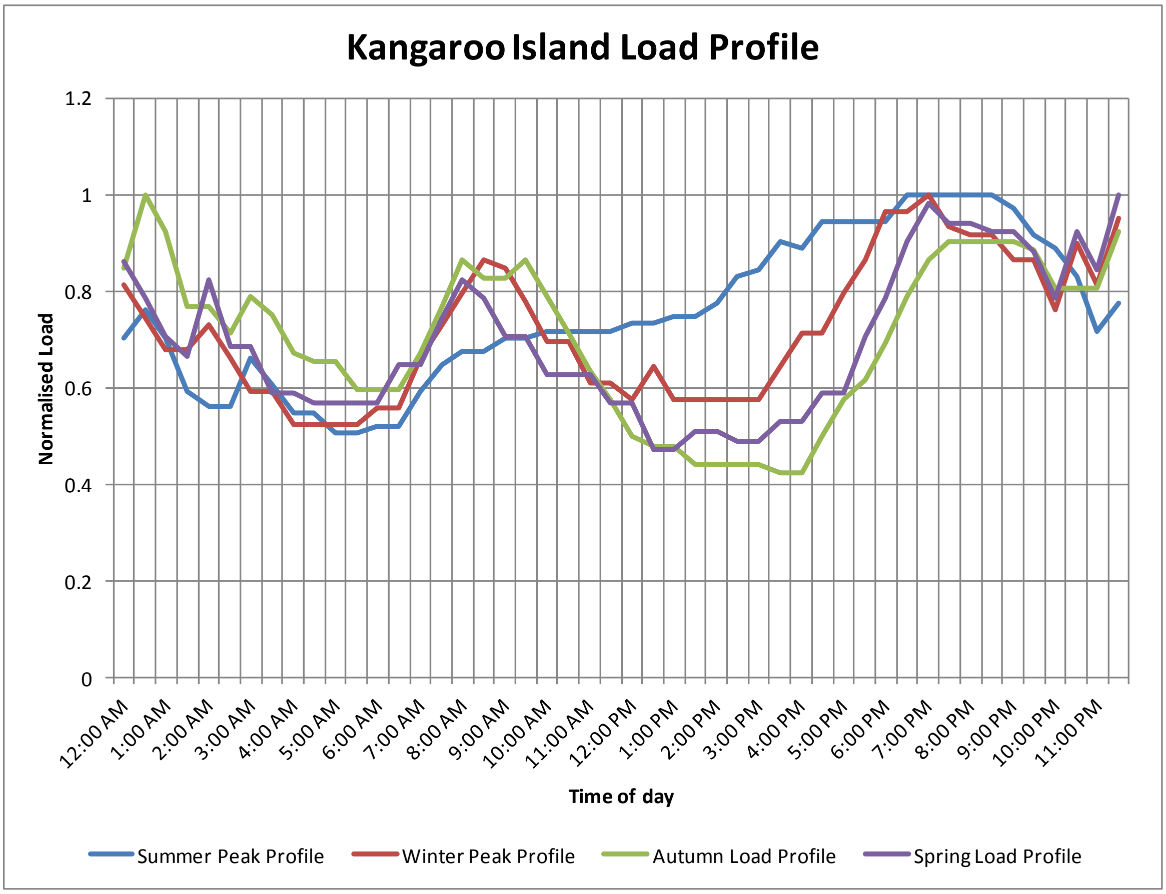

Figure 5: Daily Kangaroo Island Load Profile

Figure 5 shows the typical load profiles on Kangaroo Island during peak summer (16th January 2014), peak winter (17th July 2014), average autumn and spring period. The load profiles indicate some PV penetration with a fairly sharp peak between 15:00 and 20:00 followed by a gradual decline in demand after this time, possibly caused by the onset of a cooling sea breeze reflecting the sea side locality. The time of peak currently occurs at approximately 19:30, hence additional PV will have a negligible impact on forecast peak demand (ie solar PV output is near zero at 20:00).

Based on peak summer (16th January 2014), the load above 85% of peak occurs between 16:30 and 22:00 and is above 95% of peak between 18:00 and 21:00. The load profiles for winter, autumn and spring have similar load curves with morning peaks followed by evening and hot water peaks.

Figure 6 shows the measured peak load of 7.6MW and estimated native load (ie with PV generation removed) during the peak load summer day in 2014. Consideration of PV impact is included in the forecast information provided in Table 2.

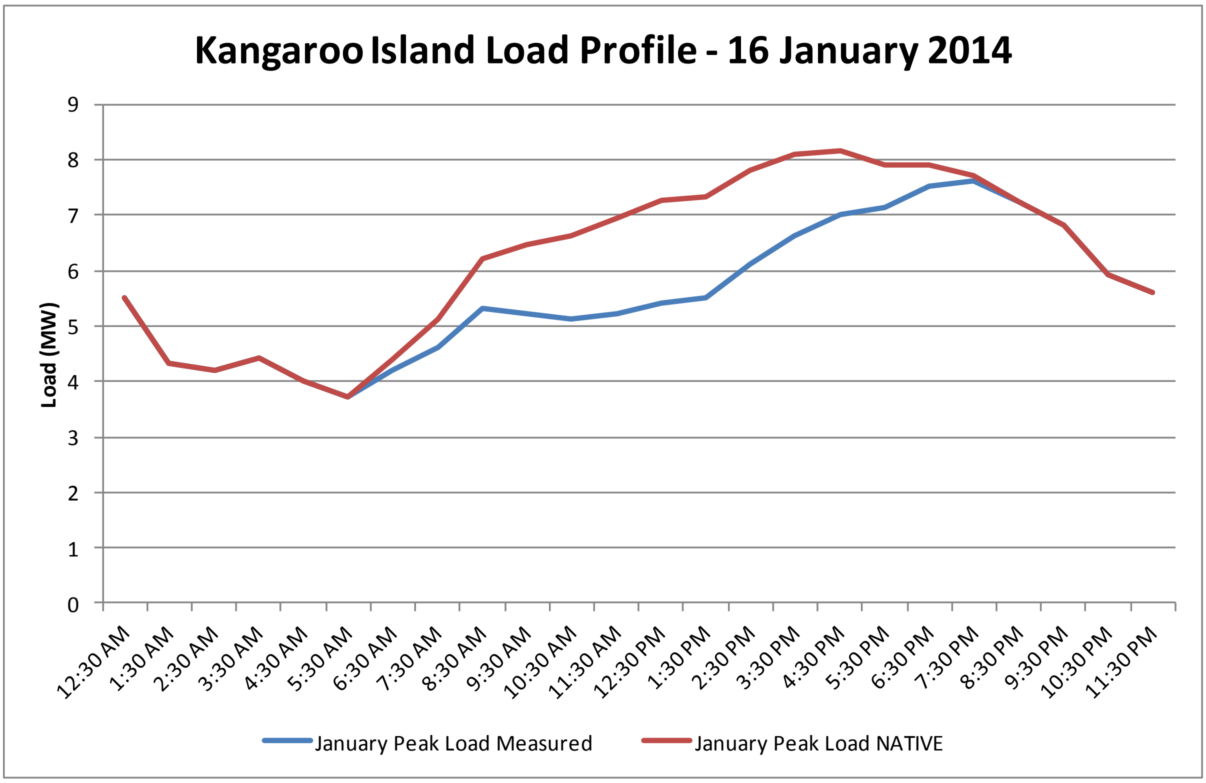

Figure 6: Kangaroo Island January Load Profile

3.5 Committed Augmentations

SA Power Networks is unaware of any committed transmission, sub-transmission or distribution projects within the area that may have an impact on the projected system limitations.

3.6 Existing and Committed Generation

SA Power Networks is unaware of any existing or committed embedded generation other than PV in the area whose operation may potentially influence the identified network need. The biggest commercial PV system on Kangaroo Island is a 50kW dual-axis solar array system that was commissioned in 2013 at Kingscote Airport. In addition, a 14kW roof mounted array was installed at the Kangaroo Island's Council Chambers in Kingscote as part of the Kangaroo Island Visible Solar Project in 2013.

3.6.1 Kingscote Power Station

SA Power Networks has a standby diesel powered power station installed at Kingscote on Kangaroo Island. The 6.0MW standby Kingscote Power Station has three Caterpillar 3516B HD generating units each rated at 2MW standby capacity with an LV (415V) brushless alternator, each coupled to individual 11/0.4kV 2MVA step-up transformers connected to the Kingscote 11kV substation bus via an 11kV ring main unit.

The generating units' 6.0MW standby capacity is capable of energising the Kangaroo Island 33kV sub-transmission network via the Kingscote Substation's 33/11kV transformers and circuit breaker to supply the existing load on Kangaroo Island via the remaining substations at McGillivray, American River and Penneshaw. The Kingscote Power Station is designed as a standby plant and normally operates for a few hours per year, to provide network support in the event of a fault or during operational maintenance and testing of generators on SA Power Networks distribution network. In the evaluation, both network and non-network solutions have access to the Kingscote Power Station as backup or for emergency use.

Installation of an additional 2MW generator is planned to be completed by the end of 2016 to meet peak load demand and mitigate the risk of long duration load shedding at such times.

3.6.2 Existing Embedded Generation

There are no known significant embedded generation installations permanently connected in Kangaroo Island other than domestic and commercial PV. SA Power Networks is not aware of any existing or committed embedded generation augmentations that could potentially impact on the distribution network servicing Kangaroo Island.

4. Description and Assumptions Made of the Identified Need

The existing radial 33kV cable is nearing the end of its expected design life of 30 years. An underwater inspection of the existing cable was completed in 2012 to assess its condition. Physical evidence of those portions of the cable that could be visually inspected demonstrated that damage to the outer armoured sheath had commenced with visible evidence of minor corrosion. This is evidence of the early signs of the cable's deterioration.

In the event of a cable failure, the expected duration of an outage to repair the 33kV submarine cable between Cuttlefish Bay and Fishery Beach is from three to twelve months (for a deep sea cable repair). The extended period for repair is a result of the difficulty in obtaining a replacement section of cable, the limited availability of cable laying and repair ships in Australia, the difficulty in locating the fault and the adverse weather and sea conditions. The estimated cost for the repair of a mid ocean cable fault excluding the operating cost of running the Kingscote generators is estimated to be about $8.32 million.

When the 33kV submarine cable fails, it may or may not be repairable. In order to ascertain this, it will be necessary to locate the fault (if possible), carefully raise the cable from the sea floor using a suitable ship and/or barge with cranes, cut the at the fault location, and raise the two sections of cable to the surface then remove water affected sections. A new section of cable is then required to be jointed to the remaining two sections of cable. Care must be taken to avoid bending or stressing the cable, which could result in further damage and consequently faults to the submarine cable.

If the structural integrity of the armour of the cable has been damaged or significantly corroded, any attempt to lift the cable to effect repairs is likely to further stress the cable cores and damage other sections of the cable. In such a case, the cable would need to be abandoned and a replacement of the cable ordered and installed. The normal delivery and installation time for a new cable is approximately twenty-four (24) months from order placement which includes design, construction and installation. It should be noted that installation is subject to suitable sea conditions to conduct such an operation, which only present at certain times of the year.

In the event of a failure of the 33kV cable, the short term electricity demand on Kangaroo Island will solely rely on the reliability of supply of SA Power Networks' existing back-up diesel power station at Kingscote Substation. However, these generators alone would be insufficient to supply Kangaroo Island in the event of a protracted outage, as would occur for a failure of the submarine cable.

For every 10 days of continuous operation, each of the existing generating units must be taken out of service whilst SA Power Networks undertakes the manufacturer's recommended programmed maintenance inspections. In addition, SA Power Networks expects a number of outages will occur due to generator operation related faults (eg failure of a generator or control scheme) during the period of operation which is for up to a twelve month (12) operating period, these generator related faults may result in the need for load shedding/rationing.

To maintain the required generation capacity to meet demand at peak load times, at least 2.6MW of temporary mobile generation would need to be installed at Kingscote Power Station. In addition, additional operating and maintenance staff would be required to operate the power station and the additional generators. This additional generation capacity would permit any single generating unit of the existing three (four from 2017) to be out of service for routine maintenance or repair, whilst still maintaining sufficient generation capacity for continuity of supply. Considerable logistical and economic issues would also be associated with providing adequate fuel and Urea supplies (urea is required to maintain environmental compliance of the power station) in the event of a protracted outage.

The cost estimate for the long term and sustained operation of the Kingscote Power Station is more than would be expected for a similar base (prime power) power station as the generators were installed for standby operation not for base load operation. The total additional cost to maintain supply to Kangaroo Island for 12 months without the use of the submarine cable is estimated to exceed $25.4 Million with fuel costs being the most significant portion of this cost.

Prior to the installation of Kingscote generators in 2006, Kangaroo Island relied entirely on supply from the mainland via the submarine cable and the radial 33kV sub-transmission line. Maintaining security of supply on the 33kV sub-transmission had been a difficult task due to the frequent stormy conditions that were experienced on Kangaroo Island. These conditions were reflected in the average minutes off supply due to the 33kV sub-transmission system of 726 minutes experienced by customers on Kangaroo Island during the period 2002 – 2006. The average minutes off supply value of the 33kV sub-transmission system has improved significantly since the installation of the backup generators with a recent 2008 – 2016 average minutes off supply of 73 mins. In an event of a cable failure, Kangaroo Island may experience poor 33kV sub-transmission reliability of supply similar to the period prior to 2006 as the 33kV line will be connected radially from Kingscote Substation to Penneshaw.

The key driver for the identified need is to maintain security of supply to Kangaroo Island, and therefore the identified need would not be for a reliability corrective action.

5. Assessment Methodology and Assumptions

5.1 Planning Criteria

As a Distribution Network Service Provider (DNSP) within the National Electricity Market, SA Power Networks must comply with technical standards contained within the National Electricity Rules and in particular to the requirements relating to the reliability and system security contained in Schedule 5.1. In addition, as a licensed distributor in South Australia, SA Power Networks is required to comply with the service obligations imposed under the South Australian Electricity Distribution Code (EDC or Code).

We have developed specific planning criteria relating to the rating of equipment, quality of supply and system security to ensure that we meet our obligations under both the NER and EDC. These criteria are described in the Distribution Annual Planning Report (DAPR) available from our website.

5.2 Reliability Standards

Under our Electricity Distribution License, we must use our best efforts to maintain feeder category standards for reliability that are defined in the Electricity Distribution Code. For the purposes of the EDC this region is mostly categorised as 'Long Rural' apart from KI31, KI32 and KI57 feeders, which are supplied from Kingscote Substation and classified as 'Short Rural'. A summary of this reliability standard is shown in Table 3.

Area Supplied	Average Minutes Off Supply per annum (SAIDI)	Average Number of Supply Interruptions per customer per annum (SAIFI)
Long Rural Feeders	300	1.95
Short Rural Feeders	220	1.85

Table 3: Relevant Reliability Standards

Please note that SA Power Networks still needs to report our reliability performance against the previous ESCOSA (Essential Services Commission of South Australia) region of Kangaroo Island, as ESCOSA still monitors our performance against our historical (average) performance, which is presently 285 SAIDI minutes[4] per annum. Whilst SA Power Networks is permitted to meet its service obligations by means of distribution network augmentation, or by procuring support services from an alternative network service provider, generator, retailer or customer, SA Power Networks is still responsible for meeting the service standards and will incur any penalties associated in not doing so.

5.3 Evaluation Test Period

The evaluation period for the RIT-D evaluation is driven by the need to obtain the most cost effective solution(s) over a reasonable time frame, allowing for uncertainties associated with future network developments and load and generation patterns. Therefore, a 25-year evaluation period has been used in undertaking the assessment of all credible options.

[4] This reliability measure excludes the impacts of Major Event Days (MEDs), with there being on average three MEDs per annum.

6. Network Options

Network option costs shown in the report exclude common costs to all options such as pre-project commitment costs, business overheads, contingencies and GST.

6.1 Network Options Considered

Options considered for replacement of the existing submarine cable include:

1. Install new submarine cable from Fishery Beach to Cuttlefish Bay in 2018.
2. Run the existing cable to failure.
3. Run the existing cable to failure but provide the capital and operating expenditure including additional spare cable to reduce the time to repair the cable (4 months).
4. Run the existing cable to failure with pre-purchase of submarine cable to reduce the cable replacement time.

6.2 Preferred Network Option

SA Power Networks preferred and recommended solution is undertaking Option 1 which will see the installation of a new submarine cable from Fishery Beach to Cuttlefish Bay in 2018, prior to the existing cable's failure.

6.2.1 Option 1: Install new submarine cable from Fishery Beach to Cuttlefish Bay in 2018

This option includes:

1. Installing a new 33kV submarine cable from Fishery Beach to Cuttlefish Bay in 2018 ($21.9 million).
   Note: Capital cost used for 33kV cable supply and installation is the average tender price from six turn-key contract tenders received in July 2016 including network management cost.
2. Termination site upgrades at Fishery Beach and Cuttlefish Bay in 2018 to provide fast switching between both cables ($3.47 million).
3. Uprating the 33kV American River to MacGillivray (T50 to T60) in 2023 to provide adequate line thermal capacity ($0.4 million).
4. Installing a 20MVA 33kV Voltage Regulator at Penneshaw Substation in 2036 to provide voltage support ($1.76 million).

Advantages

1. Maintaining security of supply to Kangaroo Island by mitigating the risk of failure of the existing cable.
2. Increases supply capacity to Kangaroo Island and solves the voltage constraint by providing adequate voltage levels along the Penneshaw to American River 33kV Line for 33/19kV SWER Isolating transformers.
3. Impact on customers is significantly reduced based on value of lost load.
4. Route is within the Special Purpose Area 7 (SPA-7) which provides an overlay to the zoning that allows ongoing operation of submarine cables with minimal impact on sensitive cultural heritage and flora/fauna areas.
5. Provides option for future telecommunication link to Kangaroo Island via fibre optic integrated into the submarine cable.
6. Minimal environmental impact such as greenhouse gas, noise pollution or fuel transportation issues.
7. Potential export of renewable energy from Kangaroo Island to mainland via cable.

Disadvantages

1. Capital expenditure in 2015-20 regulatory period.

6.3 Other Network Alternatives Considered

Other network alternatives to the replacement of the existing submarine cable were considered by SA Power Networks and have been included in the RIT-D analysis such as running the cable to failure as well as storage of a replacement cable. However, these have been shown in the RIT-D analysis not to be viable compared to the preferred network solution.

6.3.1 Option 2: Run existing cable to failure

This is not a recommended option.

This option includes:

1. Running the existing cable to failure before repairing and installing a new submarine cable and upgrading termination sites at Fishery Beach and Cuttlefish Bay.
   Note: In the event of a cable failure, the cable replacement ($21.9 million) process is executed in parallel with the repair time ($8.32 million) to allow the full cable replacement within 2 years and to limit the generation cost ($25.4 million) to the duration of the cable repair (1 year).
2. Uprating the 33kV American River to MacGillivray (T50 to T60) in 2023 to provide adequate line thermal capacity ($0.4 million).
3. Installing a 20MVA 33kV Voltage Regulator at Penneshaw Substation in 2026 to provide voltage support ($1.76 million).

Advantages

1. Lower capital expenditure in the 2015-2020 regulatory period, depending when the cable fails. Likelihood of failure increases each year (the cable's life expectancy of 30 years is reached in 2023).

Disadvantages

1. This is not a prudent option as the likelihood of cable failure is higher as it ages with major consequences (the cable's life expectancy of 30 years is reached in 2023).
2. A catastrophic failure of this cable could take up to 12 months to locate and repair or up to 24 months if the cable had to be replaced.
3. Lower customer service – reflected in value of VCR value within market benefits.

6.3.2 Option 3: Run to failure but provide the capital and operating expenditure including additional spare cable to reduce the time to repair the cable (4 months)

This is not a recommended option.

This option includes:

1. Running the existing cable to failure before repairing and installing a new submarine cable and upgrading termination sites at Fishery Beach and Cuttlefish Bay but provide additional capital and operating expenditure to provide reduced repair time (i.e. 4 months).
   Note: In the event of a cable failure, the cable replacement ($21.9 million) process is executed in parallel with the repair time ($5.4 million) to allow the full cable replacement within 2 years and to limit the generation cost (approximately $9.2 million) to the duration of the cable repair (4 months).

2. A number of pre-planning activities have to be put in place to enable a 4-month repair time:
    - Purchase of new spare cable and cable joints in 2017 (3km of spare cable, 2 sets of spare joints, 1 set of surge arrestors and 1 set of termination joints) (total $1.2 million)
    - Submarine cable storage (warehouse purchase with security system) including annual cable testing.
    - Annual retainers with fault locator company, repair company, barge company and power station operating company for their commitments to have their services available if they become needed to meet the response time.
    - New all-weather safe track to Cuttlefish Bay for small truck and bi-annual maintenance to allow fast access on Cuttlefish Bay ($5 million).
    - Replacement of existing short lived power station assets including protection and control.
3. Uprating the 33kV American River to MacGillivray (T50 to T60) in 2023 to provide adequate line thermal capacity ($0.4 million).
4. Installing a 20MVA 33kV Voltage Regulator at Penneshaw Substation in 2026 to provide voltage support ($1.76 million).

Advantages

1. Lower capital expenditure in the 2015-2020 regulatory period, depending when the cable fails.

Disadvantages

1. This is not a prudent option as the likelihood of cable failure is higher as it ages with major consequences (the cable's life expectancy of 30 years is reached in 2023).
2. A catastrophic failure of this cable could take up to 4 months to repair with pre-planning activities in place.
3. Lower customer service – reflected in value of VCR value within market benefits.

6.3.3 Option 4: Run to failure with pre-purchase of submarine cable to reduce the cable replacement time (4 months)

This is not a recommended option.

This option includes:

1. Running the existing cable to failure before installing a new submarine cable and upgrading the cable termination sites at Fishery Beach and Cuttlefish Bay but provide additional capital and operating expenditure to provide faster response time (4 months) (Cost to install replacement cable is $21.9 million).
2. A number of pre-planning activities have to be put in place to enable a 4 months' repair time:
    - Purchase full length of submarine cable and cable joints in 2017 (15km of cable, 1 set of spare joints, 2 sets of surge arrestors and 2 set of termination joints) ($5.2 million)
    - Submarine cable storage (warehouse purchase with security system) including annual cable testing.
    - Annual retainers with fault locator company, repair company, barge company and power station operating company for their commitments to have their services available if they become needed to meet the response time.
    - New all-weather safe track to Cuttlefish Bay for small truck and bi-annual maintenance to allow fast access on Cuttlefish Bay ($5 million).
    - Replacement of existing short lived power station assets including protection and control.

3. Uprating the 33kV American River to MacGillivray (T50 to T60) in 2023 to provide adequate line thermal capacity ($0.4 million).
4. Installing a 20MVA 33kV Voltage Regulator at Penneshaw Substation in 2026 to provide voltage support ($1.76 million).

Advantages

1. Lower capital expenditure in the 2015-2020 regulatory period, depending when the cable fails.

Disadvantages

1. This is not a prudent option as the likelihood of cable failure is higher as it ages with major consequences (the cable's life expectancy of 30 years is reached in 2023).
2. A catastrophic failure of this cable could take up to 4 months to install (depending on time of year) with pre-planning activities in place.
3. Lower customer service – reflected in value of VCR value within market benefits.
4. It is not practical to purchase the 15km (one length) of cable required for the full cable installation, store the cable under controlled conditions until the existing cable fails, and then find an acceptable method (to the cable supplier) of transferring the cable from storage to a cable laying ship. This is because these types of cables are normally loaded directly onto a specifically designed cable laying ship and then installed. Cable vendors advised against loading the cable onto a ship, then off the ship for storage and then back onto a cable laying ship as it would be an inefficient practice. In addition, we understand that there would be significant risk of damaging the cable during these extra handling operations. Contractors would try to avoid increasing the transhipment operation to minimise the risk of unexpected damage.
5. Insurance and warranty of the cable may expire depending on how long they are stored which further complicates this option.

7. Summary of Submissions Received in Response to the Non-Network Options Report

7.1 Non-Network Options Received

As required by the National Electricity Rules (NER), SA Power Networks must complete a formal Regulatory Investment Test – Distribution (RIT-D) prior to committing to a credible solution to solve the identified need. In April 2016, SA Power Networks commenced the formal RIT-D consultation process via a formal Non-Network Options Report (NNOR) seeking submissions from non-network providers on potential credible options to address the identified security constraint.

In order for a non-network solution to be considered viable for Kangaroo Island, it must by itself or in combination with other non-network solutions or traditional network solutions, demonstrate that it:

- resolves all of the identified network constraints;
- is of equal security performance (availability) to the proposed network solution (new cable);
- is economically viable (cost effective);
- be technically feasible in that it is possible that sufficient supply will be provided by the option to meaningfully address or defer the preferred network option; and
- is achievable within the required timeframe to resolve the identified need.

In response to this consultation, SA Power Networks received eight non-network submissions in July 2016 ranging from a combination of proven technologies such as biomass, bio-diesel, solar and wind generation, battery storage to unproven concepts, technologies and consultancy offers.

SA Power Networks has short listed three credible and compliant submissions where the proponents have provided adequate information required for RIT-D evaluation including work required by SA Power Networks and where the submissions are likely to meet the minimum requirements such as financial, technical viability, timeliness and the use of proven technology. The names of the short listed proponents have been redacted as part of this report.

7.2 Potential Credible Non-Network Options Received

The three technically credible non-network options identified that are technically comparable in addressing the identified need are as follows:

1. Applicant 1 proposed a combination of biomass, solar and diesel generation solution.
2. Applicant 2 proposed a generation solution consisting of wind, solar and diesel generation combined with short-term battery storage.
3. Applicant 3 proposed a generation solution consisting of solar and diesel generation combined with short-term battery storage. Applicant 3 also proposed a turn-key solution for the design, supply, delivery, installation and commissioning of a permanent 10MVA submarine cable across Backstairs Passage in the event of a failure of the existing submarine cable.

Non-network option costs shown in the report exclude common costs to all options such as pre-project commitment costs, business overheads, contingencies and GST.

7.2.1 Generation Proposal by Applicant 1

Applicant 1 proposed to connect approximately 16.5MW of generation to SA Power Networks Distribution Network at Kingscote Substation. The generation system proposed consists of the following generation technologies and capacities:

- 7.5MW of biomass generation (33kV connection to Kingscote Substation)
- 8.96MW of diesel generation (33kV connection to Kingscote Substation)
- 1MW of solar PV generation (33kV connection to Kingscote Substation)

There is approximately 4,000ha of pine and 15,000ha of eucalyptus plantations representing 2.4 million green tonnes of wood that may be capable of supplying a 10MW generator for up to 17 years[5]. Applicant 1 proposes to utilise biomass fuel from wood and the Kangaroo Island Council's waste stream by constructing a biomass power plant at the Kangaroo Island Council waste transfer depot which is approximately 3km from Kingscote Substation. Export from the power plant to the mainland is likely to be limited however export to the mainland is not required for ongoing operation of the plant as described in proponent's proposal. In the event of a submarine cable failure, the cable is not repaired or replaced with the plant running "islanded" to provide the primary supply to Kangaroo Island indefinitely. The thermal biomass power plant will be capable of providing up to 7.5MW, with augmentation from reciprocating diesel units providing up to 16.5 MW of generation capacity for the next 25 years. In the event of a failure of either proponent's power plant or the 33kV connection from proponent's power plant to Kingscote Substation, then the existing Kingscote standby generators would be operated to maintain supply to Kangaroo Island.

The connection of the proposed generating systems will have significant impact on the Network and hence require augmentation works to be undertaken to avoid a material degradation in the security of supply to SA Power Networks customers.

Capital costs incurred by SA Power Networks:

1. Kingscote Substation upgrade for new 33kV generation connection for proponent including major reconfiguration of the 33kV switchyard, 33kV bus extension, 33kV circuit breakers, dynamic reactive plant and a new control building. Line protection upgrade will also be required for lines between Kingscote, American River and MacGillivray Substations in 2018. The total capital cost for the substation upgrades is approximately $6.7 million.
2. Approximately 3km of dedicated 33kV underground cable connection from proponent's power plant to Kingscote Substation in 2018 ($1.3 million). Underground cable connection has been preferred over an overhead line 33kV connection due to existing vegetation issues on North Coast Road and the high reliability and security of supply that can be achieved when installing an underground cable as opposed to an overhead solution particularly considering this proposal recommends segregation of the island from the NEM post failure of the submarine cable.

Operating costs incurred by SA Power Networks:

1. A standing charge payable to Applicant 1 for basic network support for duration of the evaluation period ($1.95 million per annum, escalating at CPI).

[5] Earth Systems, 2012, Bioenergy Resource Analysis and Technology Feasibility for Kangaroo Island: Phase 1 – Resource Analysis and Technology Shortlist, Pg15 and 37.

2. An hourly fee of $300 per MWh (escalating at CPI) paid to Applicant 1 when demand is in excess of 7.5MW which requires the use of diesel generator sets to provide network generation capacity.
3. Technical evaluation, connection and support agreements, commissioning, project management and engineering excluding design costs for the connection assets in 2017 ($0.65 million).
4. Operational management for the duration of the evaluation period ($0.2 million per annum).
5. Additional fuel cost when operating the Kingscote Generators when the proponent's power plant or 33kV connection from proponent's power plant to Kingscote Substation fails. The Kingscote Power Station as a standby plant is a benefit to non-network solutions as it reduces the high VCR cost that may be incurred otherwise.

Advantages

1. Reduction in 33kV line losses on Kangaroo Island.
2. A "green" renewable based solution.
3. The provision of employment both within the power plant and the associated fuel supply businesses. Note that these are not considered in the final evaluation.
4. Potential reduction in costs for the Kangaroo Island Council due to the use of waste stream in the fuel supply. Note that these are not considered in the final evaluation.
5. Enhancement to the KI water supply availability by use of waste heat for sea water distillation. Note that these are not considered in the final evaluation.

Disadvantages

1. Loss of access to NEM once existing cable fails, with the consequence of potential uncertainty in retail function and cost to customers. Note that these are not considered in the final evaluation.
2. Lower customer service – reflected in value of VCR value within market benefits.
3. The 33kV network on Kangaroo Island will be exposed to higher interruption and reliability issues as the 33kV line will be connected radially from Kingscote Substation to Penneshaw Substation in the event of a cable failure (islanded scenario). If 33kV line from Kingscote to Penneshaw fails, all supply except Kingscote is lost.
4. Increased environmental impact such as greenhouse gas, noise and dust pollution from the running of biomass and diesel power plant. Note that these are non-financial impacts not considered in the final evaluation.
5. Additional maintenance of the Kangaroo Island road network for freight delivery of bioenergy products to support the approximately 2 tons per hour/ 48 tons per day of fuel required for the plant. Note that these are not considered in the final evaluation.
6. Potential connection limitation of new generation. Note that these are non-financial impacts not considered in the final evaluation.

7.2.2 Generation Proposal by Applicant 2

Applicant 2 proposed to connect a total of 16.6MW of generation capacity to SA Power Networks Distribution Network at Penneshaw and Kingscote Substations consisting of:

- 3MW of solar PV generation (33kV connection to Penneshaw Substation)
- 6MW of wind generation (33kV connection to Penneshaw Substation)
- 7.6MW diesel generation (11kV connection to Kingscote Substation)
- 1MWh/ 2MW short term battery storage (11kV connection to Kingscote Substation)

Applicant 2 proposed to construct a wind/solar site approximately 4.5 to 5km from Penneshaw Substation along Cape Willoughby Road. A new diesel generator plant with a total capacity of 7.6MW was proposed to be located very close or adjacent to the existing Kingscote Substation. Applicant 2 proposed to supply over 50% of annual Kangaroo Island load via renewable generation with diesel generation running as base load generation to provide load, voltage and frequency stability. Therefore, it is anticipated that diesel generation will operate with a minimum output of 14,100MWh annually. Prior to the failure of the existing submarine cable, excess renewable generation is planned to be sold to the NEM. In the event of a cable failure, the cable may not be repaired and proponent's Wind-Solar-Diesel hybrid generation will provide the primary supply to Kangaroo Island indefinitely.

The connection of the proposed generating systems will have significant impact on the Network and hence require augmentation works to be undertaken to avoid a material degradation in the security of supply to SA Power Networks customers.

Capital costs incurred by SA Power Networks:

1. Penneshaw Substation upgrade for new 33kV connection of solar/wind generation including dynamic voltage support management in 2018.
2. Approximately 5km of dedicated 33kV overhead line connection from proponent's power plant to Penneshaw Substation in 2018 ($1.7 million).
3. Kingscote Substation upgrade for new 11kV diesel generation connection in 2018 including new 11kV bus extension, one 11kV circuit breaker and new control building. Note: 11kV line or cable connection from diesel power plant to Kingscote Substation has not been costed in the evaluation due to the proposed site location.
4. 33kV line protection upgrade for lines between Kingscote, American River and MacGillivray Substations in 2018.

Note: Total 2018 capital cost for all substation upgrades on Kangaroo Island is approximately $8.3 million.

Operating costs incurred by SA Power Networks:

1. Capacity payment charge payable to Applicant 2 for basic network support for duration of the evaluation period ($4.27 million per annum, fixed).
2. Capacity payment charge (Fixed O&M) payable to Applicant 2 for duration of the evaluation period ($0.75 million per annum, escalating at CPI).
3. Energy payment of $315 per MWh (fuel and variable O&M) (escalating at CPI) payable to Applicant 2 for the use of diesel generator sets to provide base load.
4. Technical evaluation, connection and support agreements, commissioning, project management and engineering excluding design costs for the connection assets in 2017 ($0.65 million).
5. Operational management for the duration of the evaluation period ($0.2 million per annum).

Advantages

1. Reduction in 33kV line losses on Kangaroo Island.
2. A "hybrid" renewable based solution.
3. The provision of employment both within the hybrid power plants and the associated fuel supply businesses. Note that these are not considered in the final financial evaluation.
4. Maintains reliability of the 33kV network with two main supply injections from either end of the island at Penneshaw and Kingscote in the event of an islanded scenario.

Disadvantages

1. Loss of access to NEM once existing cable fails, with the consequence of potential uncertainty in retail function and cost to customers. Note that these are not considered in the final evaluation.
2. High operating expenditure.
3. Increased environmental impact such as greenhouse gas, noise and dust pollution due to the increased running of proposed diesel generators and potential negative visual impact from wind farms. Note that these are non-financial impacts not considered in the final evaluation.
4. Potential connection limitation of new generation. Note that these are non-financial impacts not considered in the final evaluation.

7.2.3 Generation Proposal by Applicant 3

Applicant 3 proposed to connect a total of 13MW of generating systems to SA Power Networks 11kV Distribution Network. Proponent's solution consists of the following:

- 8MW of diesel generation (2MW each adjacent to Kingscote, MacGillivray, American River and Penneshaw Substations)
- 5MW solar PV generation (4MW and 1MW adjacent to Kingscote and American River Substations respectively)
- Short term battery storage (if required)
- Turn-key solution by Applicant 3 for the design, supply, delivery, installation and commissioning of a 10MVA three core submarine cable across the Backstairs Passage in the event of a failure of the existing submarine cable. Submarine cable will be procured in 2018 and stored at an undercover location in Port Adelaide.

Proponent's solution does not propose separation (islanded operation) from the National Grid and National Energy Market (NEM). The generation is proposed to be available for the national spot market use when rates are economical.

The primary purpose of the generation system is to supply the total load on Kangaroo Island during a cable failure. Upon failure of the cable, Applicant 3 proposes to provide a turn-key solution for the design, supply, delivery, installation and commissioning of a 10MVA three core submarine cable across the Backstairs Passage using existing terminations at Fishery Beach and Cuttlefish Bay terminations stations. Applicant 3 has indicated that the power stations comprising diesel and solar PV generation) will supply the island during the cable installation timeframe at approximately 3 months according to Applicant 3. Applicant 3 will continually monitor and install new generators if required to meet summer or J tariff peak during the cable failure period.

The connection of the proposed generating systems will have significant impact on the Network and hence require augmentation works to be undertaken to avoid a material degradation in the security of supply to SA Power Networks customers.

Capital costs incurred by SA Power Networks:

1. Kingscote, MacGillivray, American River and Penneshaw Substation upgrades for new 11kV diesel/solar generation connection in 2018 ($7.8 million).
   Note: Cost of 11kV line or cable connections from diesel generator plant to each substation will be covered by Applicant 3.
2. Uprating the 33kV American River to MacGillivray (T50 to T60) in 2023 to provide adequate line thermal capacity ($0.4 million).

3. Installing a 20MVA 33kV Voltage Regulator at Penneshaw Substation in 2026 to provide voltage support ($1.76 million).

Operating costs incurred by SA Power Networks:

1. Capacity payment charge payable to Applicant 3 for basic network support for duration of the evaluation period ($2.7 Million per annum, escalating at CPI).
2. Technical evaluation, connection and support agreements, commissioning, project management and engineering excluding design costs for the connection assets in 2017 ($0.65 million).
3. Operational management for the duration of the evaluation period ($0.2 million per annum).

Advantages

1. Resolves the voltage constraint by providing adequate voltage support along the Penneshaw to American River 33kV Line for 33/19kV SWER Isolating transformers.

Disadvantages

1. Increased environmental impact such as greenhouse gas, noise and dust pollution due to the increased running of diesel generators. Note that these are non-financial impacts not considered in the final evaluation.
2. A catastrophic failure of this cable could take many more months to install than expected. This may be due to limited cable laying ships in Australia and adverse weather and sea conditions. Note that these are not considered in the final evaluation.
3. The new cable replacement in the event of the existing cable failure remains constrained to 10MVA due to the cable size proposed by Applicant 3. With loads on KI expected to exceed 10MVA in 2028 based on standard growth scenario, the proposed 10MVA will not meet the load requirements on the island within the next 25 years unless proponent's generators run in parallel. Note that these are not considered in the final evaluation.
4. The proponent managing the turn-key cable design and installation of the submarine project must be capable to undertake the work with acceptable methodology, environmental and safety management system. Without the supervision and full management from SA Power Networks, the quality of cable design, construction and installation may be compromised hence affecting the security of supply to Kangaroo Island. Note that these are not considered in the final evaluation.
5. This solution ultimately connects SA Power Networks mainland and Kangaroo Island network with a privately owned and operated cable which will have regulatory implications which will need to be agreed and formalised. Note that these are not considered in the final evaluation.
6. Significant risk of damaging the cable during extra handling operations from storage to cable vessel needing utmost care and expertise. Note that these are not considered in the final evaluation.
7. Insurance and warranty of the cable may expire depending on how long they are stored which further complicates the option. Note that these are not considered in the final evaluation.

7.3 Other Non-Credible Alternatives

The following submitted proposals received but have been assessed as being non credible proposals for not satisfying the minimum criteria detailed in the Non-Network Options Report (NNOR), the criteria that was not met was either using proven technology, timeliness of delivery by December 2018 or adequate risk management (the names of proponents have been redacted):

1. <u>Applicant 4</u>
   Development of a thermal energy storage system (TESS) which stores electrical energy thermally in molten silicon with proposed installation of 2MW of solar PV, 10MW of wind generation and 1MW of biomass generation. A commercial TESS prototype has been constructed and is currently undergoing testing and commissioning at Tonsley Park in South Australia.

2. <u>Applicant 5</u>
   Development of 6MW modular solar thermal technology with energy storage system including 5MW of wind generation. The system comprises of a parabolic trough concentrating thermal solar steam generator, energy storage system utilising steam accumulators and proprietary reciprocating steam piston engines for power generation. The power station can also be modified to operate from combustion generated steam via a steam boiler. The technology has not been implemented commercially however a prototype has been developed and constructed in California, USA.

3. <u>Applicant 6</u>
   Applicant 6 proposed a hybrid system consisting of 5.4MW of Solar Thermal generation, 4MW of solar PV generation, 16MW of wind generation and an isentropic management system. A 27 months' construction period was indicated as being required for engineering detailed design, approvals, installation, testing and commissioning of plant and equipment.

4. <u>Applicant 7</u>
   Submission from Applicant 7 was not a non-network proposal but a response for consultancy services to defer the cable project by implementing non-network technologies.

5. <u>Applicant 8</u>
   Development of a 3.5MW bio-fuel facility utilising steam powered generator,1MW of bio diesel generators and 1MWh battery storage units at each Kangaroo Island substations, 3MW of wind generation and a distributed community storage system or peer to peer network that will allow local energy trading within the existing Kangaroo Island network with claims of potentially reducing 50% of the electricity demand.

8. Risks and Benefits

8.1 Risks of Non-Network Solutions

It is critical to ensure the selected solution is not only the economically best choice for our customers but also meets the minimum criteria of network security, customer reliability and ability to manage future customer demand increases and generation connections such as PV.

This section describes some of the potential risks of implementing non-network solutions on Kangaroo Island which have not been considered as part of the RIT-D analysis but which need to be resolved before commitment to such solutions.

8.1.1 Regulatory Framework and Barriers

If a non-network, islanded solution is proposed for Kangaroo Island (i.e. Off Grid), the National Electricity Law and National Energy Retail Law is unlikely to apply once it is islanded. An islanded solution would require considerable stakeholder consultation (SA Government, Kangaroo Island Council, AER and ESCOSA) to determine the form of regulation and who would oversee that regulation. The finalisation of the regulatory framework that would apply under an islanded solution may take considerable time.

If required, SA Power Networks will engage with the relevant regulatory bodies and assist within our abilities or influence to finalise the regulatory framework. However, SA Power Networks are committed to strictly adhering to the NER/RIT-D requirements and the stated operational timeline of 2018. Under these circumstances, it is unlikely that the rule makers can develop and/ or finalise an agreed regulatory framework for Kangaroo Island.

8.1.2 Retail Price Control and Management

When Kangaroo Island is ultimately islanded from the National Grid, then the form of regulation established post stakeholder consultation would determine the form of price control. It is anticipated that pricing for energy consumers on Kangaroo Island may be impacted pending the regulatory framework applied as there may not be effective retail competition to supply electricity to Kangaroo Island. A price regulation framework needs to be in place prior to an islanding event to avoid the misuse or abuse of electricity suppliers having monopoly position due to lack of retail competition.

8.1.3 Development of Renewable Solution within Time Frame

All non-network options that can be considered must be capable of being operational by 1st December 2018. This short timeframe may be considered challenging due to the complications of developing and constructing infrastructure to implement the associated non-network solution with acceptable site procurement, planning and environmental approvals. Any non-network generator option must meet all relevant EDC and NER requirements related to grid connection, including if required under the NER, AEMO registration and ESCOSA licensing. Impacts on flora and fauna (potential loss of habitat) in particular cutting of tree plantations for the biomass energy solution and emissions from running diesel generators as part of the non-network solutions also need to be assessed and approved by relevant departments or action groups.

8.1.4 Sustainable Long Term Biomass Fuel Supply

In an islanded scenario, non-network options must be capable of providing solutions to the identified need for an indefinite period. Therefore, investment in any biomass energy solution must be based on the ability of securing a long term biomass fuel supply. However, the proposed complete clearing forest on Kangaroo Island does not support operating the power plane for an indefinite period. With the environmentalism or ecology on Kangaroo Island being increasingly protected, it may not be possible to secure alternative fuel sources once the existing stock is exhausted, to ensure the security of supply for a bioenergy solution[6]. A potential bush fire may also terminate the supply of bioenergy re-sources (i.e. wood) leaving the island without a secure fuel source.

[6] Earth Systems, 2012, Bioenergy Resource Analysis and Technology Feasibility for Kangaroo Island: Phase 1 – Resource Analysis and Technology Shortlist

8.2 Additional Benefits of Submarine Cable

This section describes some of the potential benefits of installing a new submarine cable and however not considered as part of the RIT-D analysis.

8.2.1 Optical Fibre in Submarine Cable

Optical fibre communication is a communication technology that uses fibre optic cables for data transmission and is generally not subject to electromagnetic interference. The optical fibre communication cables have been proposed to be embedded in the proposed submarine cable. These optic fibres could be used for third parties to improve telecommunication access to Kangaroo Island residents. As only certain cost and benefits of solution are allowed within the RIT-D for consideration, the benefit of optical fibre communication cables have not been considered in the evaluation.

8.2.2 Opportunity to Export Surplus Energy to South Australia's Electricity Grid

The development of renewable energy resources on Kangaroo Island should be explored as it brings potential local economic development whilst enhancing Kangaroo Island's prospective green image as a tourist destination. However, it is important to note that if Kangaroo Island has good renewable resources, Kangaroo Island would limit its future possibilities by removing connection to the South Australia's electricity grid via the submarine cable to export any surplus renewable energy.

Without the submarine cable connection, Kangaroo Island will no longer be connected to the National Electricity Market (NEM). Therefore, Kangaroo Island may no longer have access to competitive generation and retail market and potentially limit future development of renewable energy due to limited economic return on investment for the owners.

A recent report titled 'Towards 100% Renewable Energy for Kangaroo Island' and published by the Institute for Sustainable Futures examined Samso, an island in Denmark which is similar to a certain extent to Kangaroo Island in terms of local and tourist population, peak demand and cable distance from the mainland[7]. The Danish island of Samso is known as the first island in the world to be completely powered by renewable energy and is now exporting extensive renewable energy into the Danish grid[8]. Kangaroo Island could potentially follow the lead of Samso in the development and export of renewable energy resources provided the connection to the mainland remains, suitable capacity exists and voltage limits aren't exceeded. This conclusion is further supported by the American River Progress Association.

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[7] UTS:ISF Report - Towards 100% Renewable Energy for Kangaroo Island, Page 57

8 http://ecowatch.com/2014/05/01/samso-renewable-energy-island-sustainable-communities/

9. Market Scenarios and Benefits Considered

9.1 Quantification of Costs

9.1.1 Construction Costs

For all other costs to be incurred by SA Power Networks in all options, SA Power Networks uses a unit costing methodology to estimate the capital costs of an option. These costs are based on actual historical values spent on similar items in the recent past with any exceptional circumstances taken into account. Therefore, it represents an expected average value with an equal chance of actual costs being higher or lower than the standard figure.

Capital cost used for 33kV cable supply and installation in 2018 is the average tender price from six turn-key contract tenders received in July 2016.

Note that we include in the estimated capital cost all elements associated with the project that we are entitled to include in our Regulated Asset Base if we were to build that option.

Exclusions: Option costs shown in the report exclude common costs to all options such as pre-project commitment costs (until end of 2016), business overheads, contingencies and GST.

9.1.2 Standard Operations and Maintenance Expenditure

Operating and maintenance costs to be incurred by SA Power Networks have been derived as a fixed proportion of the initial capital cost based on average historical levels for all assets to be constructed by SA Power Networks other than the cable (1.5% per annum). SA Power Networks considers this approach to be reasonable as:

- The majority of costs in O&M are fixed in nature and therefore it is entirely appropriate to apply them over the whole of the asset base;
- For the submarine cable, an O&M equal to 0.5% of capital cost has been used as a typical proportion for the first 25 years of a long life asset with minimal O&M expenditure until cable fails.

9.1.3 Other Expenditure

Where specific Operating and Maintenance costs apply to an option such as fuel costs or licence costs for an embedded generator these are applied individually to the option in the expected year that they will be incurred.

Where payments to third parties are made – for instance in terms of an annual facilities fee these payments reflect the expected contractual payments to be made in constant (real) dollars; that is no inflation multiplier is added even if one is provided for in the contract authorising the payment.

9.2 Quantification of Market Benefits

9.2.1 Introduction

Under clause 5.17.1 (c) (4) of the NER we must consider whether or not the following potential market benefits are material to the identification of the preferred option and if material, describe the methodology we have used to determine the benefit or cost arising from each one:

(i) changes in voluntary load curtailment;
(ii) changes in involuntary load shedding and customer interruptions caused by network outages, using a reasonable forecast of the value of electricity to customers;
(iii) changes in costs for parties, other than the RIT-D proponent, due to differences in:
(A) the timing of new plant;
(B) capital costs; and
(C) the operating and maintenance costs;
(iv) differences in the timing of expenditure;
(v) changes in load transfer capacity and the capacity of Embedded Generators to take up load;
(vi) any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the National Electricity Market ;
(vii) changes in electrical energy losses; and
(viii) any other class of market benefit determined to be relevant by the AER.[9]

9.2.2 Voluntary Load Curtailment

Voluntary load curtailment occurs when a customer agrees to reduce their demand on the network for a period in response to a network constraint. The value (a negative market benefit) is evaluated by setting the value of lost production equal to the cost of the Network Support Agreement signed by or on behalf of the customer. This method results in a stream of annual costs which in turn are converted to a NPV.

This follows the method mandated by the AER in their RIT-D guidelines, a copy of which is available from their website.

Voluntary load reduction is not considered a viable standalone non-network option as it must be able to support the Kangaroo Island total demand once the Kangaroo Island cable has failed.

9.2.3 Involuntary Load Curtailment

The value of differences in expected network reliability between the various options has been included in the analysis. This benefit is calculated by:

- Estimating the expected reliability of that part of the network impacted by any of the proposed options.
- Calculating the expected MWh of electrical consumption that will not occur due to loss of supply as a result of any unplanned outages.
- Multiplying the lost consumption by a value per MWh reflecting the economic costs of the loss of supply. This uncertainty is encapsulated by using a wide band of potential values in the sensitivity analysis evaluation.
- Converting the stream of annual costs to an NPV.

Note: this benefit excludes the value of any reliability or performance scheme payments accrued or paid by SA Power Networks such as Guaranteed Service Level payments or STPIS penalties. Changes

[9] Clause 5.17.1 (c) (4) of the NER

in the expected levels of these payments are excluded from the Regulatory Test as they represent transfers of economic surplus between Market Participants.

9.2.4 Changes in Other Party Costs

We interpret this clause in the context of:

- The costs must be solely related to that parties' participation in the electricity market; and
- The party must be identifiable (i.e. an actual as distinct from a potential party);

Under this interpretation, SA Power Networks believes that there are no parties whose investment decisions, capital costs, or operating and maintenance costs will be impacted other than as included fully under other market benefits.

9.2.5 Differences in the Timing of Expenditure

No specific identifiable value for this class of benefits has been calculated as:

- Differences caused by the initial timing of expenditure are fully included in the evaluation of the costs of each option through the NPV analysis.
- As this cable is reaching near its end of life, and condition being one of the key indicators of asset life[10], the risk of a cable failure unceasingly (and significantly) increases with time. This risk directly correlates to the risk of maintaining the security of supply as required by our obligations under both of the South Australian Electricity Distribution Code (EDC) and National Electricity Rules (NER). Therefore, based on the associated risk of the predicted service life of the cable and the materiality of the economic impact upon a failure of this cable, our analysis has demonstrated that it would be prudent and efficient to install a second undersea cable by December 2018, and when the existing cable will be approximately 25 years old. In supporting this analysis, the Australian Energy Regulator's (AER) in its final decision for SA Power Networks' 2015-20 price determination, have stated that their own analysis supported that it would be prudent to install a second undersea cable by December 2018[11].
- Differences in value caused by the differing life of the installed assets are resolved in the NPV analysis by adding back into each option the remaining life of the assets (as represented by the remaining deprecated value of the assets) deployed in the solution.

9.2.6 Changes in Load Transfer Capacity

There are no specific values attributed to this class of benefits as differences in load transfer capacity between options during the study period are included in:

- The timing of capital expenditure where these changes allow the deferral of expenditure (e.g. by allowing load to be transferred from a heavily loaded substation to one less heavily loaded); or
- Changes in Involuntary Load Curtailment where load can be transferred temporarily to another source of supply following a network outage.

The study period applied is long enough for differences that may allow deferral or improvements outside of the period to be small enough to be non-material to the outcome.

[10] Due to the physical limitation of inspecting the underground cable, condition inspection is very difficult, however, in 2012 SA Power Networks were able to carry out a condition assessment on some exposed sections. These sections have identified corrosion being evident with derogation of the cable's outer sheath.

[11] Australian Energy Regulator, Final Decision SA Power Networks Determination 2015-20, Attachment 6 – Capital Expenditure, Oct 2015, pg 68-71.

9.2.7 Changes in Embedded Generation Capacity

There are no embedded generators within the area of the study suffering from network capacity constraints as a result of the network configuration during the period of the study.

The value of the loss of residential sized PV generation caused by involuntary load shedding has been calculated by adding back to the shed load, an estimate of the amount of lost generation during the loss of supply. For instance: Substation A has a peak measured load of 15 MW which includes an estimated 1 MW of PV generation. When calculating the value of involuntary load shedding a peak load of 16 MW (15 MW measured + 1 MW lost PV generation) is used for the load at Substation A.

9.2.8 Electrical Losses

The value due to changes in the level of electrical losses has been included in the evaluation of the options. This value is calculated by:

- Estimating the expected peak loss for the network for each option for each year of study;
- Converting the loss into an annual MWh quantity by multiplying by a calculated loss load factor specific to the area of the network under consideration;
- Multiplying the estimated total annual MWh of system losses by the average cost of production in the South Australian market; and
- Converting the stream of annual costs to an NPV

Note that the average market price tends to vary over the years depending on the fuel mix and level of government taxes and subsidies. This uncertainty is encapsulated by using a wide band of potential values in the sensitivity analysis as described in Section 9.3.6.

9.2.9 Impact On Market Behaviour

Under the RIT-D, changes in market behaviour caused by differences between the options should be considered. These impacts include changes in the bidding behaviour of generation companies and the level of voluntary load shedding during system peaks. These changes are driven both by changes in the level of market competition and by changes in the average cost of production. In this case, SA Power Networks has deemed that there will be no material change in market behaviour due to:

- Any diesel powered generation in the options only displaces other diesel powered generation rather than other generation sources.
- The size of the proposed power stations is immaterial when compared to the overall peak demand in the South Australian market and therefore any proposed generation does not threaten to displace any other planned or existing generation within the State or NEM.

9.2.10 Other Market Benefits

No other market benefits have been included in the evaluation.

9.3 Parameters Subject to Variation Within the Sensitivity Analysis

9.3.1 Base Case

The base case consists of the mid-range value of each varied element below. This represents the most likely expected outcome.

9.3.2 Demand Forecasts

As changes in demand are the major determinant in the timing of network augmentations, two high level scenarios have been included, reflecting standard and flat (nil) growth rates. Within each demand growth scenario further variations have been chosen to further test the sensitivity of the results. These minor variations have been applied equally to each growth scenario as described in Section 10.2.

Standard Growth

This is the case with the highest probability in which growth in the network follows its forecast values. For details of the methodology used to derive this case please refer to the Distribution Annual Planning Report (DAPR) published annually on our website.

Flat Growth

In this case growth follows a flat rate beyond 2017.

9.3.3 Discount Rate

The allowed rate of return is the forecast of the cost of funds a network business requires to attract investment in the network. The RIT-D requires the NPV analysis to apply a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector.

The AER has stated that:

- "the regulatory WACC might reasonably be considered the lower boundary of the discounts rate but not the mean value around which sensitivity testing is conducted"; and
- "the discount rate adopted for the purpose of the regulatory test evaluation should be a commercial discount rate in order to ensure network and non-network investments are compared on a competitively neutral basis".

SA Power Networks has determined that the appropriate real pre-tax weighted average cost of capital for non-regulated work is between 4.0 and 8.5 percent. In assessing whether the rate at the lower or higher end of the range should be applied, consideration should be given to factors such as the period of the investment, counterparty risk, size, complementary business opportunities and other risk strategies and adjustments.

In our view, it is reasonable for this evaluation of credible options to use a base rate of 6.36% with the current real pre-tax Weighted Average Cost of Capital (4.36%) and 8.36% being used as the low and high values (nearly double the real pre-tax WACC) respectively.

9.3.4 SA Power Networks Project Costs

SA Power Networks has prepared cost estimates for the work it would have to undertake for each augmentation option. This includes the network changes required to support connection of each third party option to the network. These costs are based on standard historical costs adjusted to current dollar values. These costs do not include any allowance for risk, overheads or contingencies. Variations of 75% and 133% of the base values have been used to assess the potential impact of variations in construction costs and the impact of unforeseen events.

For network options requiring the existing cable to run to failure, please note that the capital contribution is derived as the cost of repair in year N and replacement in N+1 both multiplied by the chance of cable failure in year N as this acts as the trigger for the action.

Please note that no capital or operating expenses spent prior to project commitment have been included as these are considered to be common costs for all scenarios.

9.3.5 Value of Customer Reliability (VCR)

The Value of Customer Reliability (VCR)[12] published in 2015 by AEMO shall be used to reflect how much customers are willing to pay to have secure supply.

When undertaking the assessment of credible options, a base rate of $38,000 per MWh has been applied. Variations of 70% and 130% of the base value have been used to assess the potential impact of variations in VCR costs ($26,600 and $49,400 per MWh).

For network options requiring the existing cable to run to failure and Applicant 1's non-network proposal, the radial line risk is caused by the 33kV lines from Kingscote to Penneshaw being radially fed from the power station. These are also adjusted by the cable risk as the risk only occurs when the cable is out of service.

9.3.6 Cost of Losses/ Energy Price

The evaluation has used $67.10 per MWh as the base which is the average price for energy purchases for South Australia for 2016 as published by AEMO on 11th October 2016[13]. A rate of $46.14 per MWh was used as the low value based on average Victorian price in 2016 as published on 11th October 2016. A value equivalent to 150% of the base value was used for the high value ($92.51 per MWh) given the uncertainties in the calculation process and future generation costs.

Market benefits associated with the change in losses have been quantified and multiplied with the energy price.

9.3.7 Kingscote Power Station

The operational costs estimate for the ongoing operation of the Kingscote standby 8 MW power station are much higher than would be expected for a similar base (prime power) power station. The Kingscote power station was designed for standby capacity for short durations of operation for either network support or interruptions in supply and hence the generators are only suitable as a short term solution. Therefore, a base value of $589 per MWh of generation has been used for Kingscote Power Station.

[12] http://www.aemo.com.au/Electricity/Planning/Value-of-Customer-Reliability-review
[13] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM

In the event of a cable failure which requires Kingscote power station's generators to run for an extended period, the generation cost applied in the RIT-D is allocated to the energy cost (fuel/urea cost), fixed mobilisation and demobilisation of leased generators and variable operating time cost per day multiplied by the chance of cable failure in the associated year.

The availability factor of Kingscote power station's generators is predicted to be 99.93% which represents 6.1 hours of interruption of supply per year based on reliability data on remote power stations run by the state government under the Remote Areas Energy Supply Scheme.

No allowance has been included to expand the Kingscote Power Station in the 25-year evaluation period as it is considered to be a common cost for all scenarios.

9.3.8 New Submarine Cable Cost

The average offer price submitted by the cable tenderers including network management cost of approximately $21.9 million has been used in the RIT-D evaluation. However, we expect the actual price to reduce during potential contract negotiation phase.

9.3.9 Probability of Cable Failure

A normal distribution curve based on the standard deviation of the square root of the expected life of a cable has been used to formulate the probability of failure of the existing cable. The RIT-D analysis scales the annual probability of failure rate by assuming no cable failure before 2017.

9.4 Parameters Not Subject to Variation within the Sensitivity Analysis

9.4.1 Third Party Cost

The price offered to SA Power Networks for the supply of network system support services has not been subjected to specific variations in project costs, operating and maintenance costs or depreciation as the risk reflected in these variations is carried by the third party and not the electricity market.

9.4.2 Operating and Maintenance Costs

Operating and maintenance costs have been derived as a fixed proportion of the capital cost. It is considered highly unlikely that any specific elements exist in this instance that would cause a variation from the network average on a systemic basis. Therefore, no analysis has been done for a variation in the O&M costs.

9.4.3 New Submarine Cable Repair Cost

Although there is a small risk of the new submarine cable failing prior to its design lifetime (minimum of 30 years), it is considered that the operating and maintenance (O&M) costs (0.5% per annum) of the cable will substantially cover the risk times the expenses of any cable repair or maintenance within the evaluation period.

SA Power Networks is seeking from the cable tenderers an extended warranty period for the cable following the expiry of the defects liability period for the cable installation works. This will negate any expenses required from SA Power Networks to repair the cable during the infant mortality stage of the new cable.

It is expected that the warranty inclusion will not increase the cost of the cable supply and installation beyond that currently included in the evaluation.

9.4.4 Depreciation

In all cases, the capital cost was depreciated using a straight line method over the life of the asset. The remaining asset life (the depreciated value of the asset) was added back in the final year of the evaluation as an approximation of the residual value of each augmentation. Each set of assets was split into three cost components and depreciated according to the following asset lives:

- Lines = 50 years
- Substations = 45 years
- Generator Reactive Support = 20 years

No variation has been applied to depreciation rates as it is considered unlikely that a substantial variation in the expected life of the assets will occur.

10. Options Evaluation

This section provides information on the results of the Net Present Value (NPV) analysis for each technically credible option as part of the RIT-D evaluation to deliver a solution which provides the highest market benefit or lowest economic cost to all energy consumers.

The options considered as part of the RIT-D evaluation:

- Option 1 Install new submarine cable from Fishery Beach to Cuttlefish Bay in 2018.
- Option 2 Run the existing cable to failure, repair and install a new submarine cable post failure of the existing cable.
- Option 3 Run the existing cable to failure but provide the capital and operating expenditure including additional spare cable to reduce the time to repair the cable.
- Option 4 Run the existing cable to failure with pre-purchase of submarine cable to reduce the cable replacement time.
- Option 5 A non-network solution consisting of biomass, solar and diesel generation as proposed by Applicant 1.
- Option 6 A non-network hybrid solution consisting of wind, solar and diesel generation combined with short-term battery storage as proposed by Applicant 2
- Option 7 A non-network generation solution consisting of solar and diesel as proposed by Applicant 3 with a turn-key solution for the design, supply, delivery, installation and commissioning of a 10MVA submarine cable when the existing submarine cable fails.

10.1 Unweighted Results

The evaluation tables below summarise the outcome of each scenario over the standard and flat load growth projections.

Table 4: Unweighted Results ($’000’s) based on standard growth

Options	Description	Total Costs	Relative Market Benefit	Net Benefit	Rank
Option 1	Install new submarine cable	$25,618	$7,276	-$18,342	1
Option 2	Run to failure	$42,234	$0	-$42,234	6
Option 3	Run to Failure with quick repair time	$35,263	$4,854	-$30,409	4
Option 4	Run to Failure with pre-purchase of full length of cable	$32,997	$4,854	-$28,143	3
Option 5	Applicant 1 - biomass, solar and diesel generation	$33,326	$5,454	-$27,872	2
Option 6	Applicant 2 - wind, solar and diesel generation	$99,858	$12,257	-$87,601	7
Option 7	Applicant 3 - diesel and solar generation and future submarine cable installation	$42,241	$7,276	-$34,965	5

Table 5: Unweighted Results ($’000’s) based on flat growth

Options	Description	Total Costs	Relative Market Benefit	Net Benefit	Rank
Option 1	Install new submarine cable	$25,089	$5,786	-$19,302	1
Option 2	Run to failure	$39,734	$0	-$39,734	6
Option 3	Run to Failure with quick repair time	$33,632	$3,860	-$29,772	4
Option 4	Run to Failure with pre-purchase of full length of cable	$31,366	$3,860	-$27,506	2
Option 5	Applicant 1 - biomass, solar and diesel generation	$32,922	$3,643	-$29,279	3
Option 6	Applicant 2 - wind, solar and diesel generation	$99,858	$8,948	-$90,910	7
Option 7	Applicant 3 - diesel and solar generation and future submarine cable installation	$41,090	$5,786	-$35,304	5

The “Total Costs” is the summation of the direct costs associated with the various NPV of each option’s augmentation costs including total capital, operating and maintenance cost. The results show that installing a new submarine cable in 2018 (Option 1) delivers the lowest total capital cost followed by the option of running cable to failure with pre-purchase of full length of cable (Option 4). Option 6 has the highest capital cost due to the high operating expenditure (contractual and energy payment) in both growth scenarios.

The” Relative Market Benefit” represents the value of the market benefit when compared to the option that has no additional market benefit which is Option 2. A higher “Relative Market Benefit” value represents the reduction in losses or improved customer reliability for that option compared to the worst option (Option 2). The results show that Option 6 delivers the highest additional benefit due to reduction in network losses and minimal VCR cost. This is followed by Option 7 and the installation of the new submarine cable in 2018 (Option 1). It is important to note that although Option 5 delivers a reduction in network losses, the VCR cost incurred is high because the 33kV network on Kangaroo Island will be exposed to increased number of interruptions and reliability issues, as the 33kV line will be connected radially from Kingscote Substation to Penneshaw Substation following failure of the existing submarine cable (islanded scenario) as there would be no backup supply to Penneshaw for a failure of the 33kV sub-transmission system.

The “Net Benefit” is calculated in net present value terms by deducting the “Total Costs” from the “Relative Market Benefit” (a negative net benefit represents a cost to the market). The ranking within the “Net Benefit” section indicates the most economic option. In each case (standard and flat growth), the preferred option of installing a new submarine cable from Fishery Beach to Cuttlefish Bay in 2018 has been found to be the most economic choice for providing the highest net market benefit or lowest economic cost.

10.2 Weighted Sensitivity Analysis Results

All seven options described in sections 6 and 7.2 were evaluated over a range of scenarios as described in section 9. The sensitivity assessment examines the variations in relation to the distribution discount rate, cost of losses/ energy price, value of customer reliability and network capital costs. The weighted tables below summarise the outcome of each scenario over the standard and flat growth projections.

Table 6: Sensitivity Analysis Results ($'000's) based on standard growth

Options	Description	Total Costs	Relative Market Benefit	Net Benefit	Rank
Option 1	Install new submarine cable	$25,629	$7,344	-$18,285	1
Option 2	Run to failure	$42,319	$0	-$42,319	6
Option 3	Run to Failure with quick repair time	$35,343	$4,899	-$30,444	4
Option 4	Run to Failure with pre-purchase of full length of cable	$33,069	$4,899	-$28,170	3
Option 5	Applicant 1 - biomass, solar and diesel generation	$33,558	$5,645	-$27,913	2
Option 6	Applicant 2 - wind, solar and diesel generation	$100,612	$12,522	-$88,090	7
Option 7	Applicant 3 - diesel and solar generation and future submarine cable installation	$42,531	$7,344	-$35,187	5

Table 7: Sensitivity Analysis Results ($'000's) based on flat growth

Options	Description	Total Costs	Relative Market Benefit	Net Benefit	Rank
Option 1	Install new submarine cable	$25,095	$5,834	-$19,260	1
Option 2	Run to failure	$39,803	$0	-$39,803	6
Option 3	Run to Failure with quick repair time	$33,703	$3,892	-$29,810	4
Option 4	Run to Failure with pre-purchase of full length of cable	$31,428	$3,892	-$27,536	2
Option 5	Applicant 1 - biomass, solar and diesel generation	$33,146	$3,756	-$29,390	3
Option 6	Applicant 2 - wind, solar and diesel generation	$100,612	$9,113	-$91,498	7

Option 7	Applicant 3 - diesel and solar generation and future submarine cable installation	$41,372	$5,834	-$35,537	5

The sensitivity analysis results show that installing a new submarine cable in 2018 (Option 1) delivers the lowest total capital cost followed by the option of running the cable to failure with pre-purchase of full length of cable (Option 4). Consistent with the unweighted results, Option 6 delivers the highest “Relative Market Benefit” value followed by Option 7 and the installation of the new submarine cable in 2018 (Option 1).

In each case after the sensitivity assessment for standard and flat load growth, the preferred option of installing a new submarine cable from Fishery Beach to Cuttlefish Bay in 2018 was the most economic choice for providing the highest net market benefit or lowest economic cost. This is followed by the biomass, solar and diesel generation by Applicant 1 (Option 5) based on standard growth or the option of running the cable to failure with pre-purchase of full length of cable (Option 4) based on flat growth scenario.

In conclusion, the sensitivity analysis has demonstrated that installing a new submarine cable from Fishery Beach to Cuttlefish Bay in 2018 (Option 1) has the highest Net Market Benefit or lowest economic costs under all scenarios considered.

The raw sensitivity analysis results are detailed in Section 14 Attachment 1.

11. Conclusions

11.1 Preferred Option

Based on the analysis of all potentially credible options considered and the performance of a sensitivity analysis of those parameters which could have a material effect on the outcome of the analysis, installing a new submarine cable from Fishery Beach to Cuttlefish Bay in 2018 (option 1) has been shown to have the greatest net market benefit or lowest economic cost and is therefore the preferred option to resolve the identified need.

This recommended option includes:

1. Installing a new 33kV submarine cable from Fishery Beach to Cuttlefish Bay in 2018.
2. Termination site upgrades at Fishery Beach and Cuttlefish Bay in 2018 to provide fast switching between both cables.
3. Uprating the 33kV American River to MacGillivray (T50 to T60) in 2023 to provide adequate line thermal capacity.
4. Installing a 20MVA 33kV Voltage Regulator at Penneshaw Substation in 2036 to provide voltage support.

The total project cost of this recommended option is estimated to be $25.6 million in present value terms[14].

11.2 Request for Submission

Submission in response to this Draft Project Assessment Report (DPAR) should be directed to the following e-mail:

requestforproposals@sapowernetworks.com.au

Telephone enquiries can be directed to Pat Howard on (08) 8404 5514 or Andrew Lim on (08) 8404 5410.

Submissions in response to this DPAR are due on or before Wednesday, 14th December 2016.

11.3 Next Steps

Submissions received to this Draft Project Assessment Report (DPAR) may be included in the Final Project Assessment Report (FPAR)[15]. The Final Project Assessment Report represents the final stage of the consultation process in relation to the application of the formal RIT-D process.

SA Power Networks will endeavour to publish the Final Project Assessment Report (FPAR) by the end of December 2016.

[14] The $25.6M cost is based on a competitive tender process and it excludes corporate business overheads, contingencies and preliminary project costs whereas the initial $45M estimate of the NNOR was based on the total project cost using high level budget estimates from suppliers. Further savings were achieved by modifying the technical specification of the submarine cable to reflect the future forecast requirements on Kangaroo Island.

[15] Please identify in your submission if you do not wish for your submission to be publically available or included in the FPAR.

12. Compliance Statement

This Project Assessment Report complies with the requirements of NER Clause 5.17.4. (j) as demonstrated below.

Table 8: Regulation compliance cross reference

Requirement		Report Section
(1)	a description of the identified need;	4
(2)	the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary);	3 and 4
(3)	if applicable, a summary of, and commentary on, the submissions on the non-network options report	7
(4)	a description of each credible option assessed;	6 and 7
(5)	where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option;	9
(6)	a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;	6 and 7
(7)	a detailed description of the methodologies used in quantifying each class of cost and market benefit;	5 and 9
(8)	where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option;	9
(9)	the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	10
(10)	the identification of the proposed preferred option;	11.1
(11)	for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (iii) the indicative capital and operating cost (where relevant); (iv) a statement and accompanying detailed analysis that the proposed preferred option satisfies the *regulatory investment test for distribution*; (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	6.2 and 11
(12)	contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	2.3 and 11.2

13. Definitions and Contractions

Words and phrases within this document should be read with the meaning given to them within the National Electricity Rules.

Term	Meaning
AEMC	Australian Energy Market Commission.
AEMO	Australian Energy Market Operator.
AER	Australian Energy Regulator.
Base Case	The case considered most likely used as the reference case when considering alternative plausible market scenarios
CPI	Consumer Price Index
DAPR	Distribution Annual Planning Report.
DM	Demand Management
DNSP	Distribution Network Service Provider
EDC	Electricity Distribution Code.
ESCOSA	Essential Services Commission of South Australia
Identified Need	The objective or purpose of a proposed network investment.
KI31	Kingscote 11kV feeder
KI32	Brownlow 11kV feeder
KI57	Emu Bay 19kV SWER feeder
LLF	Loss Load Factor
NEM	National Electricity Market.
NER	National Electricity Rules.
NNOR	Non-Network Options Report
NPV	Net Present Value
O&M	Operating and Maintenance
PoE	Probability of Exceedance. The probability that, in any one year, peak demand will exceed the forecast value. For instance demand is expected to exceed a 50% PoE forecast, 1 year in 2.
PV	Photovoltaic
QOS	Quality of Supply
RCA	Reliability Corrective Action.
RIT-D	Regulatory Investment Test – Distribution.
Rules	National Electricity Rules (NER)
SAIDI	System Average Interruption Duration Index
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
TNSP	Transmission Network Service Provider.
Q & A	Question and Answer
VCR	Value of Customer Reliability.
WACC	Weighted Average Cost of Capital

14. Attachment 1 – Raw Sensitivity Analysis Results

Evaluation Study Results - Standard growth ($'000's)

Variation	Options	Rank	Net Benefit	Total Costs	Relative Market Benefit	Capital Costs	O&M	External Gen	VCR	Losses
Default	1	1	-$18,341.88	$25,618.22	$7,276.34	$23,383.32	$1,964.36	$270.53	$0.00	$20,163.72
Default	2	6	-$42,234.30	$42,234.30	$0.00	$15,500.12	$26,463.64	$270.53	$7,276.34	$20,163.72
Default	3	4	-$30,408.81	$35,262.68	$4,853.87	$22,670.83	$12,321.32	$270.53	$2,422.47	$20,163.72
Default	4	3	-$28,142.94	$32,996.81	$4,853.87	$24,087.12	$8,639.16	$270.53	$2,422.47	$20,163.72
Default	5	2	-$27,872.03	$33,325.65	$5,453.62	$6,600.12	$1,341.14	$25,384.40	$6,654.57	$15,331.87
Default	6	7	-$87,601.20	$99,858.00	$12,256.79	$8,114.00	$1,648.95	$90,095.05	$0.00	$15,183.27
Default	7	5	-$34,964.84	$42,241.18	$7,276.34	$7,400.07	$1,492.85	$33,348.25	$0.00	$20,163.72
Low Discount	1	1	-$16,301.33	$25,578.71	$9,277.38	$22,841.90	$2,407.50	$329.31	$0.00	$24,376.21
Low Discount	2	6	-$46,364.28	$46,364.28	$0.00	$16,080.76	$29,954.21	$329.31	$9,277.38	$24,376.21
Low Discount	3	3	-$31,020.51	$37,208.74	$6,188.24	$22,807.71	$14,071.73	$329.31	$3,089.14	$24,376.21
Low Discount	4	2	-$28,048.76	$34,236.99	$6,188.24	$23,923.07	$9,984.62	$329.31	$3,089.14	$24,376.21
Low Discount	5	4	-$32,271.25	$38,979.74	$6,708.49	$6,222.59	$1,645.05	$31,112.10	$8,624.13	$18,320.97
Low Discount	6	7	-$105,939.71	$121,454.19	$15,514.48	$7,649.30	$2,022.61	$111,782.29	$0.00	$18,139.11
Low Discount	7	5	-$40,421.45	$49,698.83	$9,277.38	$7,075.04	$1,853.30	$40,770.48	$0.00	$24,376.21
High Discount	1	1	-$19,646.15	$25,462.35	$5,816.19	$23,601.93	$1,633.46	$226.96	$0.00	$17,028.35
High Discount	2	6	-$38,511.70	$38,511.70	$0.00	$14,652.18	$23,632.57	$226.96	$5,816.19	$17,028.35
High Discount	3	4	-$29,368.37	$33,248.52	$3,880.15	$22,100.10	$10,921.47	$226.96	$1,936.04	$17,028.35
High Discount	4	3	-$27,737.05	$31,617.20	$3,880.15	$23,811.57	$7,578.68	$226.96	$1,936.04	$17,028.35
High Discount	5	2	-$24,468.00	$29,002.60	$4,534.60	$6,787.30	$1,112.98	$21,102.31	$5,225.93	$13,084.01
High Discount	6	7	-$73,757.01	$83,641.55	$9,884.54	$8,344.48	$1,368.43	$73,928.65	$0.00	$12,960.00
High Discount	7	5	-$30,691.73	$36,507.92	$5,816.19	$7,508.90	$1,224.48	$27,774.54	$0.00	$17,028.35
Low Losses	1	1	-$18,341.88	$25,618.22	$7,276.34	$23,383.32	$1,964.36	$270.53	$0.00	$15,086.01
Low Losses	2	6	-$42,234.30	$42,234.30	$0.00	$15,500.12	$26,463.64	$270.53	$7,276.34	$15,086.01
Low Losses	3	4	-$30,408.81	$35,262.68	$4,853.87	$22,670.83	$12,321.32	$270.53	$2,422.47	$15,086.01
Low Losses	4	2	-$28,142.94	$32,996.81	$4,853.87	$24,087.12	$8,639.16	$270.53	$2,422.47	$15,086.01

Variation	Options	Rank	Net Benefit	Total Costs	Relative Market Benefit	Capital Costs	O&M	External Gen	VCR	Losses
Low Losses	5	3	-$29,088.81	$33,325.65	$4,236.85	$6,600.12	$1,341.14	$25,384.40	$6,654.57	$11,470.94
Low Losses	6	7	-$88,855.40	$99,858.00	$11,002.60	$8,114.00	$1,648.95	$90,095.05	$0.00	$11,359.75
Low Losses	7	5	-$34,964.84	$42,241.18	$7,276.34	$7,400.07	$1,492.85	$33,348.25	$0.00	$15,086.01
High Losses	1	1	-$18,341.88	$25,618.22	$7,276.34	$23,383.32	$1,964.36	$270.53	$0.00	$30,245.59
High Losses	2	6	-$42,234.30	$42,234.30	$0.00	$15,500.12	$26,463.64	$270.53	$7,276.34	$30,245.59
High Losses	3	4	-$30,408.81	$35,262.68	$4,853.87	$22,670.83	$12,321.32	$270.53	$2,422.47	$30,245.59
High Losses	4	3	-$28,142.94	$32,996.81	$4,853.87	$24,087.12	$8,639.16	$270.53	$2,422.47	$30,245.59
High Losses	5	2	-$25,456.11	$33,325.65	$7,869.55	$6,600.12	$1,341.14	$25,384.40	$6,654.57	$22,997.81
High Losses	6	7	-$85,110.98	$99,858.00	$14,747.02	$8,114.00	$1,648.95	$90,095.05	$0.00	$22,774.90
High Losses	7	5	-$34,964.84	$42,241.18	$7,276.34	$7,400.07	$1,492.85	$33,348.25	$0.00	$30,245.59
Low VCR	1	1	-$20,524.78	$25,618.22	$5,093.44	$23,383.32	$1,964.36	$270.53	$0.00	$20,163.72
Low VCR	2	6	-$42,234.30	$42,234.30	$0.00	$15,500.12	$26,463.64	$270.53	$5,093.44	$20,163.72
Low VCR	3	4	-$31,864.97	$35,262.68	$3,397.71	$22,670.83	$12,321.32	$270.53	$1,695.73	$20,163.72
Low VCR	4	3	-$29,599.10	$32,996.81	$3,397.71	$24,087.12	$8,639.16	$270.53	$1,695.73	$20,163.72
Low VCR	5	2	-$28,099.37	$33,325.65	$5,226.28	$6,600.12	$1,341.14	$25,384.40	$4,699.00	$15,331.87
Low VCR	6	7	-$89,784.11	$99,858.00	$10,073.89	$8,114.00	$1,648.95	$90,095.05	$0.00	$15,183.27
Low VCR	7	5	-$37,147.74	$42,241.18	$5,093.44	$7,400.07	$1,492.85	$33,348.25	$0.00	$20,163.72
High VCR	1	1	-$16,158.97	$25,618.22	$9,459.24	$23,383.32	$1,964.36	$270.53	$0.00	$20,163.72
High VCR	2	6	-$42,234.30	$42,234.30	$0.00	$15,500.12	$26,463.64	$270.53	$9,459.24	$20,163.72
High VCR	3	4	-$28,952.65	$35,262.68	$6,310.03	$22,670.83	$12,321.32	$270.53	$3,149.21	$20,163.72
High VCR	4	2	-$26,686.78	$32,996.81	$6,310.03	$24,087.12	$8,639.16	$270.53	$3,149.21	$20,163.72
High VCR	5	3	-$27,644.69	$33,325.65	$5,680.96	$6,600.12	$1,341.14	$25,384.40	$8,610.13	$15,331.87
High VCR	6	7	-$85,418.30	$99,858.00	$14,439.70	$8,114.00	$1,648.95	$90,095.05	$0.00	$15,183.27
High VCR	7	5	-$32,781.93	$42,241.18	$9,459.24	$7,400.07	$1,492.85	$33,348.25	$0.00	$20,163.72
Low Distr Capital	1	1	-$17,470.22	$24,746.57	$7,276.34	$22,511.67	$1,964.36	$270.53	$0.00	$20,163.72
Low Distr Capital	2	6	-$41,377.94	$41,377.94	$0.00	$14,773.88	$26,333.53	$270.53	$7,276.34	$20,163.72
Low Distr Capital	3	4	-$28,183.29	$33,037.16	$4,853.87	$20,445.31	$12,321.32	$270.53	$2,422.47	$20,163.72

Variation	Options	Rank	Net Benefit	Total Costs	Relative Market Benefit	Capital Costs	O&M	External Gen	VCR	Losses
Low Distr Capital	4	2	-$25,913.34	$30,767.21	$4,853.87	$21,857.52	$8,639.16	$270.53	$2,422.47	$20,163.72
Low Distr Capital	5	3	-$26,222.00	$31,675.62	$5,453.62	$4,950.09	$1,341.14	$25,384.40	$6,654.57	$15,331.87
Low Distr Capital	6	7	-$85,572.70	$97,829.50	$12,256.79	$6,085.50	$1,648.95	$90,095.05	$0.00	$15,183.27
Low Distr Capital	7	5	-$33,114.82	$40,391.16	$7,276.34	$5,550.06	$1,492.85	$33,348.25	$0.00	$20,163.72
High Distr Capital	1	1	-$19,492.46	$26,768.80	$7,276.34	$24,533.90	$1,964.36	$270.53	$0.00	$20,163.72
High Distr Capital	2	6	-$43,364.69	$43,364.69	$0.00	$16,458.77	$26,635.39	$270.53	$7,276.34	$20,163.72
High Distr Capital	3	4	-$33,346.49	$38,200.36	$4,853.87	$25,608.51	$12,321.32	$270.53	$2,422.47	$20,163.72
High Distr Capital	4	3	-$31,086.01	$35,939.88	$4,853.87	$27,030.19	$8,639.16	$270.53	$2,422.47	$20,163.72
High Distr Capital	5	2	-$30,050.07	$35,503.69	$5,453.62	$8,778.16	$1,341.14	$25,384.40	$6,654.57	$15,331.87
High Distr Capital	6	7	-$90,278.82	$102,535.62	$12,256.79	$10,791.62	$1,648.95	$90,095.05	$0.00	$15,183.27
High Distr Capital	7	5	-$37,406.86	$44,683.20	$7,276.34	$9,842.10	$1,492.85	$33,348.25	$0.00	$20,163.72

<u>Evaluation Study Results - Flat growth ($'000's)</u>

Variation	Options	Rank	Net Benefit	Total Costs	Relative Market Benefit	Capital Costs	O&M	External Gen	VCR	Losses
Default	1	1	-$19,302.29	$25,088.51	$5,786.22	$22,975.54	$1,886.45	$226.51	$0.00	$18,326.25
Default	2	6	-$39,733.87	$39,733.87	$0.00	$14,536.70	$24,970.66	$226.51	$5,786.22	$18,326.25
Default	3	4	-$29,772.11	$33,632.29	$3,860.18	$21,707.41	$11,698.37	$226.51	$1,926.04	$18,326.25
Default	4	2	-$27,506.24	$31,366.42	$3,860.18	$23,123.69	$8,016.21	$226.51	$1,926.04	$18,326.25
Default	5	3	-$29,279.17	$32,922.04	$3,642.87	$6,600.12	$1,341.14	$24,980.78	$5,192.34	$15,277.25
Default	6	7	-$90,909.86	$99,858.00	$8,948.14	$8,114.00	$1,648.95	$90,095.05	$0.00	$15,164.33
Default	7	5	-$35,303.64	$41,089.85	$5,786.22	$6,436.65	$1,304.96	$33,348.25	$0.00	$18,326.25
Low Discount	1	1	-$17,711.50	$24,972.13	$7,260.63	$22,403.02	$2,298.53	$270.58	$0.00	$21,891.17
Low Discount	2	6	-$43,515.91	$43,515.91	$0.00	$15,083.46	$28,161.87	$270.58	$7,260.63	$21,891.17
Low Discount	3	3	-$30,543.31	$35,386.72	$4,843.41	$21,810.41	$13,305.74	$270.58	$2,417.21	$21,891.17
Low Discount	4	2	-$27,571.56	$32,414.97	$4,843.41	$22,925.77	$9,218.63	$270.58	$2,417.21	$21,891.17

Variation	Options	Rank	Net Benefit	Total Costs	Relative Market Benefit	Capital Costs	O&M	External Gen	VCR	Losses
Low Discount	5	4	-$34,107.72	$38,376.33	$4,268.61	$6,222.59	$1,645.05	$30,508.69	$6,634.12	$18,249.07
Low Discount	6	7	-$110,416.57	$121,454.19	$11,037.62	$7,649.30	$2,022.61	$111,782.29	$0.00	$18,114.18
Low Discount	7	5	-$41,188.26	$48,448.89	$7,260.63	$6,077.74	$1,600.67	$40,770.48	$0.00	$21,891.17
High Discount	1	1	-$20,309.80	$25,006.79	$4,696.99	$23,236.63	$1,576.80	$193.37	$0.00	$15,644.58
High Discount	2	6	-$36,325.43	$36,325.43	$0.00	$13,756.79	$22,375.27	$193.37	$4,696.99	$15,644.58
High Discount	3	4	-$28,672.39	$31,806.17	$3,133.78	$21,204.71	$10,408.09	$193.37	$1,563.20	$15,644.58
High Discount	4	3	-$27,041.07	$30,174.85	$3,133.78	$22,916.18	$7,065.30	$193.37	$1,563.20	$15,644.58
High Discount	5	2	-$25,564.14	$28,729.68	$3,165.53	$6,787.30	$1,112.98	$20,829.39	$4,134.30	$13,041.74
High Discount	6	7	-$76,245.32	$83,641.55	$7,396.23	$8,344.48	$1,368.43	$73,928.65	$0.00	$12,945.34
High Discount	7	5	-$30,774.02	$35,471.01	$4,696.99	$6,613.52	$1,082.95	$27,774.54	$0.00	$15,644.58
Low Losses	1	1	-$19,302.29	$25,088.51	$5,786.22	$22,975.54	$1,886.45	$226.51	$0.00	$13,711.26
Low Losses	2	6	-$39,733.87	$39,733.87	$0.00	$14,536.70	$24,970.66	$226.51	$5,786.22	$13,711.26
Low Losses	3	3	-$29,772.11	$33,632.29	$3,860.18	$21,707.41	$11,698.37	$226.51	$1,926.04	$13,711.26
Low Losses	4	2	-$27,506.24	$31,366.42	$3,860.18	$23,123.69	$8,016.21	$226.51	$1,926.04	$13,711.26
Low Losses	5	4	-$30,046.98	$32,922.04	$2,875.06	$6,600.12	$1,341.14	$24,980.78	$5,192.34	$11,430.07
Low Losses	6	7	-$91,706.11	$99,858.00	$8,151.89	$8,114.00	$1,648.95	$90,095.05	$0.00	$11,345.58
Low Losses	7	5	-$35,303.64	$41,089.85	$5,786.22	$6,436.65	$1,304.96	$33,348.25	$0.00	$13,711.26
High Losses	1	1	-$19,302.29	$25,088.51	$5,786.22	$22,975.54	$1,886.45	$226.51	$0.00	$27,489.38
High Losses	2	6	-$39,733.87	$39,733.87	$0.00	$14,536.70	$24,970.66	$226.51	$5,786.22	$27,489.38
High Losses	3	4	-$29,772.11	$33,632.29	$3,860.18	$21,707.41	$11,698.37	$226.51	$1,926.04	$27,489.38
High Losses	4	2	-$27,506.24	$31,366.42	$3,860.18	$23,123.69	$8,016.21	$226.51	$1,926.04	$27,489.38
High Losses	5	3	-$27,754.67	$32,922.04	$5,167.37	$6,600.12	$1,341.14	$24,980.78	$5,192.34	$22,915.88
High Losses	6	7	-$89,328.89	$99,858.00	$10,529.10	$8,114.00	$1,648.95	$90,095.05	$0.00	$22,746.49
High Losses	7	5	-$35,303.64	$41,089.85	$5,786.22	$6,436.65	$1,304.96	$33,348.25	$0.00	$27,489.38
Low VCR	1	1	-$21,038.15	$25,088.51	$4,050.35	$22,975.54	$1,886.45	$226.51	$0.00	$18,326.25
Low VCR	2	6	-$39,733.87	$39,733.87	$0.00	$14,536.70	$24,970.66	$226.51	$4,050.35	$18,326.25
Low VCR	3	4	-$30,930.16	$33,632.29	$2,702.13	$21,707.41	$11,698.37	$226.51	$1,348.23	$18,326.25

Variation	Options	Rank	Net Benefit	Total Costs	Relative Market Benefit	Capital Costs	O&M	External Gen	VCR	Losses
Low VCR	4	2	-$28,664.29	$31,366.42	$2,702.13	$23,123.69	$8,016.21	$226.51	$1,348.23	$18,326.25
Low VCR	5	3	-$29,489.33	$32,922.04	$3,432.71	$6,600.12	$1,341.14	$24,980.78	$3,666.64	$15,277.25
Low VCR	6	7	-$92,645.72	$99,858.00	$7,212.28	$8,114.00	$1,648.95	$90,095.05	$0.00	$15,164.33
Low VCR	7	5	-$37,039.50	$41,089.85	$4,050.35	$6,436.65	$1,304.96	$33,348.25	$0.00	$18,326.25
High VCR	1	1	-$17,566.42	$25,088.51	$7,522.08	$22,975.54	$1,886.45	$226.51	$0.00	$18,326.25
High VCR	2	6	-$39,733.87	$39,733.87	$0.00	$14,536.70	$24,970.66	$226.51	$7,522.08	$18,326.25
High VCR	3	3	-$28,614.05	$33,632.29	$5,018.24	$21,707.41	$11,698.37	$226.51	$2,503.85	$18,326.25
High VCR	4	2	-$26,348.18	$31,366.42	$5,018.24	$23,123.69	$8,016.21	$226.51	$2,503.85	$18,326.25
High VCR	5	4	-$29,069.01	$32,922.04	$3,853.03	$6,600.12	$1,341.14	$24,980.78	$6,718.05	$15,277.25
High VCR	6	7	-$89,173.99	$99,858.00	$10,684.01	$8,114.00	$1,648.95	$90,095.05	$0.00	$15,164.33
High VCR	7	5	-$33,567.77	$41,089.85	$7,522.08	$6,436.65	$1,304.96	$33,348.25	$0.00	$18,326.25
Low Distr Capital	1	1	-$18,532.58	$24,318.80	$5,786.22	$22,205.83	$1,886.45	$226.51	$0.00	$18,326.25
Low Distr Capital	2	6	-$39,160.80	$39,160.80	$0.00	$14,051.31	$24,882.98	$226.51	$5,786.22	$18,326.25
Low Distr Capital	3	4	-$27,787.45	$31,647.63	$3,860.18	$19,722.75	$11,698.37	$226.51	$1,926.04	$18,326.25
Low Distr Capital	4	2	-$25,517.50	$29,377.68	$3,860.18	$21,134.95	$8,016.21	$226.51	$1,926.04	$18,326.25
Low Distr Capital	5	3	-$27,629.14	$31,272.01	$3,642.87	$4,950.09	$1,341.14	$24,980.78	$5,192.34	$15,277.25
Low Distr Capital	6	7	-$88,881.36	$97,829.50	$8,948.14	$6,085.50	$1,648.95	$90,095.05	$0.00	$15,164.33
Low Distr Capital	7	5	-$33,694.47	$39,480.69	$5,786.22	$4,827.49	$1,304.96	$33,348.25	$0.00	$18,326.25
High Distr Capital	1	1	-$20,318.30	$26,104.52	$5,786.22	$23,991.55	$1,886.45	$226.51	$0.00	$18,326.25
High Distr Capital	2	6	-$40,490.34	$40,490.34	$0.00	$15,177.42	$25,086.40	$226.51	$5,786.22	$18,326.25
High Distr Capital	3	4	-$32,391.86	$36,252.04	$3,860.18	$24,327.16	$11,698.37	$226.51	$1,926.04	$18,326.25
High Distr Capital	4	2	-$30,131.38	$33,991.56	$3,860.18	$25,748.83	$8,016.21	$226.51	$1,926.04	$18,326.25
High Distr Capital	5	3	-$31,457.21	$35,100.08	$3,642.87	$8,778.16	$1,341.14	$24,980.78	$5,192.34	$15,277.25
High Distr Capital	6	7	-$93,587.48	$102,535.62	$8,948.14	$10,791.62	$1,648.95	$90,095.05	$0.00	$15,164.33
High Distr Capital	7	5	-$37,427.73	$43,213.95	$5,786.22	$8,560.75	$1,304.96	$33,348.25	$0.00	$18,326.25