# REVIEW OF THE SOUTH AUSTRALIAN ELECTRICITY TRANSMISSION CODE

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| DOCUMENT REF: | ETC Review 2010 |
| VERSION: | 1.0 |
| DATE: | 23 December 2010 |
| FINAL | |

# Contents

## Executive Summary

The Essential Services Commission of South Australia (ESCOSA) is responsible for establishing and monitoring the reliability standards specified in the South Australian Electricity Transmission Code (ETC). The ETC outlines the reliability standards to be met by ElectraNet Pty Ltd (ElectraNet), the planner and operator of the main electricity transmission network in South Australia.

Prior to each transmission regulatory reset period, ESCOSA reviews the ETC to identify any connection points that can be economically upgraded to a higher reliability standard.

In consultation with ESCOSA, ElectraNet, and ETSA Utilities, AEMO reviewed the ETC wording and connection point reliability standards. This included consideration of proposed amendments to clarify the ETC's intent, along with a cost-benefit assessment to establish any appropriate upgrades to existing connection point reliability standards.

This cost-benefit assessment identified that a new second transformer is economically justified at both the Baroota and Dalrymple connection points, and AEMO has recommended an upgrade of their reliability standard from Category 1 to Category 2.

To allow reasonable time for the proposed augmentations and to align ETSA Utilities' required works with its next regulatory period, the proposed timing for reclassification is as follows:

- Baroota reclassified to Category 2 effective from 1 December 2017.
- Dalrymple reclassified to Category 2 effective from 1 December 2016.

AEMO has also recommended a number of amendments it considers are in line with the intent of the ETC and the National Electricity Rules (NER), and that will help to clarify the obligations the ETC aims to impose on ElectraNet.

The ETC wording review has included the restructuring of Category 5 and 6 regarding supply to the Adelaide Central[1] and surrounding suburbs. This includes the following:

- Removing the existing Category 5 formula used to calculate the portion of load requiring N-2 reliability.
- Removing one of the six categories by moving Category 5 connection points to the existing Category 4, moving the existing Category 6 grouped connection points to a new Category 5, and deleting the existing Category 5.
- Confirming that the reliability standards are minimum standards, and that Adelaide Central can therefore be supported by connection points in other categories (where the connection points are connected through the meshed sub-transmission network and where that meshed sub-transmission network is capable of supply the required power to Adelaide Central) by enabling them to increase their level of supply if economically feasible.
- Proposing new ETC clauses that promote joint planning between ElectraNet, ETSA Utilities, and other transmission network service providers.

To ensure breaches in the reliability standards are dealt with promptly, AEMO has proposed reducing the timeframe to remedy a breach to a 12-month obligation, removing the previous 3-year grace period. To enable this, it is proposed that committed augmentations be based on a 3-year forecast agreed maximum demand, developed by ETSA Utilities and direct connect customers, rather than the 12-month out contracted agreed maximum demand currently applied.

To better align with the NER, AEMO has recommended removing limitations on the amount that network support options can be utilised to supply agreed maximum demand. Currently, the agreed maximum demand is not allowed to exceed 120% of the transmission network's capacity, with the 20% above transmission capacity able to be supplied by network support arrangements.

[1] As defined in Section 10.1 of the Electricity Transmission Code ET/05 (V2), Adelaide Central means that area of Adelaide which is located east of West Terrace, north of South Terrace, west of East Terrace and south of the River Torrens

ElectraNet raised concerns about the Murraylink interconnector's capability at times of peak demand, and calculating the level of support Murraylink can provide to the Riverland region. AEMO has advised that Murraylink's power transfer capability should be based on the transfer limit equation applied in operations. Additionally, it was clarified that any contingencies in other National Electricity Market (NEM) regions should be considered in the assessment of reliability standards, and that meeting the reliability levels in one region might require augmentation in an adjacent region.

Category 3 is understood to be an interruptible N-1 reliability standard. To clarify this, some minor wording amendments to the ETC have been proposed.

AEMO considers that some ETC clauses can be misinterpreted to potential contradict the defined reliability standard categories by appearing to prevent ElectraNet from shedding load. AEMO proposes minor wording amendments to clarify the intent of these clauses.

# 1 Introduction

The Essential Services Commission of South Australia (ESCOSA) is responsible for establishing and monitoring the reliability standards specified in the South Australian Electricity Transmission Code (ETC)[2]. The ETC outlines the reliability standards to be met by ElectraNet Pty Ltd (ElectraNet), the planner and operator of the main electricity transmission network in South Australia.

The reliability standards were last reviewed by ESCOSA in 2006 to assist ElectraNet in determining its capital expenditure for the July 2008 to June 2013 regulatory period. Assisting with this review, the Electricity Supply Industry Planning Council (ESIPC), now part of the Australian Energy Market Operator Ltd. (AEMO), assessed and reported on connection point reliability standards.

On 25 March 2010, Patrick Walsh, Chairperson of ESCOSA, wrote to AEMO requesting its input into the current ESCOSA review. The purpose of ESCOSA's review is to ensure that clear and efficient reliability standards are maintained to enable ElectraNet to understand its obligations, and customers to understand the level of reliability they can expect. This review is timed to assist ElectraNet with determining its capital expenditure requirements for the July 2013 to June 2018 regulatory period.

Specifically, ESCOSA requested AEMO to consider the following matters:

- AEMO's perspective on how a connection point's reliability should be established.
- The appropriateness of each connection point's reliability category, and whether categories should be increased for particular connection points, taking into consideration load growth, demographic changes, and transmission network developments.
- Recommendations outlining any proposed reliability standard improvements, based on the assessment of cost effective network augmentations to meet the proposed standard.

AEMO's review has been completed in consultation with ESCOSA, ElectraNet, and ETSA Utilities, the planner and operator of the electricity distribution network in South Australia.

This report outlines AEMO's connection point reliability standard assessment, and ETC amendment recommendations that AEMO considers are consistent with the ETC's intent and that help to clarify the obligations imposed by the ETC.

[2] ESCOSA, 2008, *Electricity Transmission Code ET/05 (V2)*, http://www.escosa.sa.gov.au/electricity-overview/codes-guidelines-rules/electricity-codes.aspx

# 2 Transmission Planning

The purpose of transmission planning is to identify a flexible, robust, and operable transmission system that reliably serves all loads in a cost-effective manner.

## 2.1 Jurisdictional planning standards

Planning standards set the balance between reliability and cost in transmission planning. In general, higher reliability standards result in additional investment in transmission facilities and higher investment costs.

Transmission reliability standards are concerned with both security and reliability, in both the short term (i.e. operational) and the long term (i.e. planning).

National Electricity Market (NEM) jurisdictional standards relating to security and reliability in an operational timeframe must be aligned with the technical standards as specified in the National Electricity Rules (NER)[3] - schedules 5.1a and 5.1. Jurisdictional transmission reliability standards complement the NER's, and can provide a greater degree of prescription about how reliability and security will be met in the operational timeframe.

The NEM jurisdictional reliability standards applied in a transmission planning timeframe are defined in jurisdiction-specific transmission codes, licenses, legislation, or network management plans.

Reliability standards are commonly expressed either deterministically or probabilistically.

Deterministic transmission reliability standards require the transmission system to continue to provide adequate and secure supplies of energy to customers after any of a range of contingencies. Potential contingencies involve outages (faults or failures) of some important power system elements, such as lines, transformers, or generators. A deterministic standard does not take outage probabilities into account.

Deterministic standards are commonly expressed in the following way:

- 'N' reliability means the transmission system can supply the maximum demand, provided all network elements are in service. This means that the loss of a single transmission element (a line, a transformer, or other associated equipment) can cause supply interruption to some customers.
- 'N-1' reliability provides a higher level of reliability. This means customers will not be affected with even one network element out of service. It is also possible to define N–1 reliability for a percentage of the time or for a percentage of the maximum demand.
- 'N–2' reliability means that customers will not be affected with even two network elements out of service. This is a very high level of security requiring significant capital expenditure to achieve. Accordingly, this level of reliability generally only applies to central business districts with large customer concentration.

Probabilistic transmission reliability standards require the transmission system to provide adequate and secure supplies of energy to customers under a wide range of contingencies. This explicitly takes the probabilities of contingencies occurring into account (for example, transformer failure rates), under a range of possible operating conditions (for example, demand levels and network topologies) with their own assigned probabilities. Each contingency is treated as a random event, with some events more likely to occur than others.

In the NEM, Queensland, New South Wales, and Tasmania use deterministic planning standards. Victoria uses a probabilistic standard. South Australia uses a probabilistic standard expressed as a deterministic standard, which is derived using economic considerations, but is expressed deterministically.

[3] Australian Energy Market Commission, 2010, *National Electricity Rules Version 39*, http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html.

## 2.2 Regulatory framework

The NEM regulatory framework includes a prescribed process for determining new investment, referred to as the Regulatory Investment Test for Transmission (RIT-T)[4]. This decision-making process is intended to identify the most economic new transmission network development options, or non-network alternatives, needed to maintain the national transmission network in a suitably reliable state.

The NER defines the framework and scope of the RIT-T that the Australian Energy Regulator (AER) publishes (consistent with the NER framework and scope), as well as more detailed guidelines on its application.

NER clause 5.6.5B (b) defines the purpose of the RIT-T as follows:

> ‘The purpose of the *regulatory investment test for transmission* is to identify the *credible option* that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the *market* (the *preferred option*). For the avoidance of doubt, a *preferred option* may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the *identified need* is for *reliability corrective action*.’

[4] Australian Energy Regulatory, 2010, *Regulatory investment test for transmission*, http://www.aer.gov.au/content/index.phtml/itemId/730920

# 3 Electricity Transmission Code

ElectraNet is licensed by ESCOSA to operate the main South Australian electricity transmission network. As a condition of licence, ElectraNet is required to comply with the ETC, which sets out ElectraNet's obligations in relation to the provision of transmission services in South Australia, in addition to its obligations under the NER and other relevant legislation, regulations, or any statutory instrument.

AEMO has been advised that the South Australian State Government originally introduced the ETC as part of the long-term lease under which ElectraNet gained responsibility for the development, operation, and maintenance of the South Australian transmission network.

Section 2 of the ETC establishes specific reliability standards for the ElectraNet transmission network. It's understood that the original reliability standards were based on transmission load connection point reliability levels provided in the 12 months prior to establishing the ETC, with the intention that transmission customers would not experience a reduction in the level of reliability as a result of the long-term lease of the transmission assets.

## 3.1 Reliability categories

The ETC allocates each ElectraNet transmission network connection point (or group of connection points) connecting either to the ETSA Utilities distribution network or to the supply points of a small number of large, direct-connect customers, to a defined reliability category. The ETC requires ElectraNet to maintain the specified level of reliability and supply restoration standards for each reliability category.

The ETC currently defines six reliability categories for South Australian connection points. The level of reliability increases from N, where a single outage can lead to complete loss of supply at the connection point, to an interruptible N-2 level of reliability, where two concurrent outages will lead to only a portion of lost load.

Each category defines both the capacity required at each connection point and the restoration time to restore full capacity after an interruption.

The level of reliability outlined in the ETC can be achieved through transmission network augmentation or (to a limited extent) by network support arrangements including distribution system capability, generating unit capability, load interruption ability, or some combination of all of these.

ElectraNet is required to follow the RIT-T process defined in the NER when it augments the transmission network to maintain reliability.

In the case of a new connection point, ElectraNet is required to seek ESCOSA's approval for the applicable reliability standards that must be developed, having regard to a range of factors including the size of the load, value of lost load, the types and numbers of customers supplied through the connection point, and the location. The development of a new connection point is also subject to the RIT-T framework.

Table 1 summarises the six reliability categories set out in the existing ETC (ET/05 V2).

*Table 1 - Summary of the existing reliability standard categories*

| Category | Interpretation |
|---|---|
| 1 | **N line and transformer:**<br>Agreed maximum demand contracted up to 100% of line or transformer capacity or, where appropriate network support is available, up to 120% of line or transformer capacity.<br>N equivalent line capacity and N equivalent transformer capacity.<br>Equivalent line capacity must be restored within two days of an interruption.<br>Equivalent transformer capacity must be restored within eight days of an interruption. |
| 2 | **N line, firm[1] N-1 transformer:**<br>Agreed maximum demand contracted up to 100% of line or transformer capacity or, where appropriate network support is available, up to 120% of line or transformer capacity.<br>N equivalent line and N-1 equivalent transformer capacity, without interruption.<br>Equivalent line capacity must be restored within two days of an interruption. |
| 3 | **N-1 non-firm[2] line and transformer:**<br>Agreed maximum demand contracted up to 100% of line or transformer capacity or, where appropriate network support is available, up to 120% of line or transformer capacity.<br>N equivalent line capacity and N equivalent transformer capacity with full N backup supply available within one hour of an interruption (best endeavours).<br>Equivalent line capacity must be restored within two days of an interruption. |
| 4 | **N-1 firm[1] line and transformer:**<br>Agreed maximum demand contracted up to 100% of line or transformer capacity.<br>N-1 equivalent line capacity and N-1 equivalent transformer capacity provided without interruption to supply in the event of a transmission plant failure.<br>Equivalent line capacity restored within 12 hours of an interruption (best endeavours). |
| 5 | **N-1 firm[1] line and transformer, partial N-2 line and transformer:**<br>Agreed maximum demand contracted up to 100% of line or transformer capacity.<br>N-1 equivalent line capacity and N-1 equivalent transformer capacity provided without interruption in the event of a transmission plant failure.<br>N-2 equivalent line capacity and N-2 equivalent transformer capacity provided without interruption in the event of a transmission plant failure to a calculated portion of the total demand.<br>Equivalent line capacity restored within four hours of an interruption (best endeavours). |
| 6 | **N-1 firm[1] line and transformer provided from diverse connection points:**<br>Agreed maximum demand contracted up to 100% of line or transformer capacity.<br>Until 31 December 2011, N line capacity and N transformer capacity.<br>After 31 December 2011, N-1 equivalent line capacity and N-1 equivalent transformer capacity provided by independent and diverse transmission substations without interruption in the event of a transmission plant failure.<br>Contracted transmission line capacity restored within four hours of an interruption (best endeavours). |
| 1. 'Firm' means that the required level of redundancy must be provided without any interruption to supply.<br>2. 'Non-firm' means that the required level of supply can be supplied after post-contingent operation, such as start-up of local generation or sub-transmission network switching to supply the connection point demand. | |

All categories impose a 12-month best endeavours clause and a 3-year obligation to correct any breach of the performance standards.

## 3.2 Reliability standard review process

The ETC's transmission reliability standards are expressed deterministically in the six reliability standard categories.

As demand at a connection point increases over time, so does the economic cost of losing the connection point's supply. The economically efficient approach may be to increase the connection point's level of reliability and revise its category in a new version of the ETC.

To account for these impacts, ESCOSA undertakes a periodic review of the ETC's reliability standards to identify the appropriate level of reliability that each connection point should be supplying, within the next regulatory review's forecast period and beyond.

# 4 Review of the Reliability Standards

AEMO reviewed the appropriateness of the current ETC's connection point standards. The review was based on the methodology developed by ESIPC in the 2005 ETC review[5].

## 4.1 Methodology

A probabilistic cost-benefit approach has been used to compare the capital cost of moving to the next reliability category with the value of the increased reliability delivered to the relevant connection point.

The assessment process for each connection point involved the following considerations:

- Calculating the average number of hours each connection point will be without power. This probabilistic method relies on typical failure rate data, which is based on historical observations, and is collected for different categories of equipment (transformers, lines, cables) at different voltage levels.
- Multiplying the number of outage hours by the connection point demand to establish the number of megawatt hours (MWh) that, on average, are unable to be supplied each year.
- Assessing the value of lost customer load or unserved energy, as being the number of lost MWh multiplied by the cost of unserved energy to customers.
- For connection points with a high value of lost customer load, comparing the capital cost of upgrading to a higher reliability standard with the benefit, in reduced unserved energy, the upgrade provides.

Using the assessment process above and applying the assumptions outlined in the following section, the cost of expected unserved energy (USE) was calculated as follows:

$USE =

VCR [$/MWh] x MD [MW] x (supply bus outage duration [hr] + transformer forced outage duration [hr])

+ VCR [$/MWh] x MD [MW] x average load factor of 0.49 x (line forced outage duration [hr]

+ line planned outage duration [hr] + transformer planned outage duration [hr])

## 4.2 Assumptions

### 4.2.1 Demands

The connection point maximum demand forecasts used for this assessment are ETSA Utilities' medium growth connection point forecasts, and represent the summer peak demand forecasts. The forecasts present the undiversified annual connection point maximum demands from 2010/11 through to 2029/30 and are presented in ElectraNet's Annual Planning Report 2010–2030[6].

As transformers are more likely to fail when under stress during peak load periods, the forecast maximum demand was assumed for calculating the value of expected unserved energy due to transformer outages.

Transmission line and cable faults, on the other hand, are generally less dependent on line loading. As such, an average load factor was used to convert the maximum demand to average demand, which was then used when calculating the value of expected unserved energy due to line outages. Similarly, the average load factor was applied when calculating the expected unserved energy during a planned outage, including demand not met due to a forced outage when a parallel transmission element is assumed out of service for planned maintenance. The load factor is

[5] Electricity Supply Industry Planning Council (2005), *Transmission Code Review*, http://www.escosa.sa.gov.au/Publications/DownloadPublication.aspx?id=683&versionId=661

[6] ElectraNet (2010), *Annual Planning Report 2010-2030,* http://www.electranet.com.au/network_planning_review.html

defined as the ratio of the average demand load to the maximum demand. Calculation of the assessment's load factor was based on the 2009/10 South Australian total system load duration curve.

The average load factor applied to all connection points was 49%.

### 4.2.2 Transmission system reliability

To calculate the expected hours of unserved energy per annum, ElectraNet provided the average failure rates and outage durations due to planned and unplanned outages, based on historical outage information for the South Australian transmission network.

Local factors and the varying condition of individual transmission plant make it difficult to independently verify transmission plant outage rates. However, to support the robustness of the data provided by ElectraNet, AEMO compared ElectraNet's transmission plant outage rates with industry-wide statistics, as well as with Victorian transmission plant outage rates recorded over an 18-year period. Although only considered for information purposes, the comparisons suggest that ElectraNet's transmission plant outage rates are in line with those typically experienced industry-wide. For more information about the comparisons, see Appendix C.

The outage information has been broken down according to five key plant items: low-rated connection-point transformers (such as those generally used to supply small Category 1, 2, and 3 loads), high-rated connection-point transformers (such as those used to supply some Category 4 loads and Adelaide Central), 132 kV lines, 275 kV lines, and 275 kV cables.

Table 2 outlines the reliability levels assumed for the assessment.

*Table 2 – Transmission Reliability Levels – Historical Averages*

| Transmission element | Failure rate | | Outage duration | |
|---|---|---|---|---|
| | Failure rate per line and cable (faults/annum/100 km length) | Failure rate per connection transformer (faults/annum) | Duration per fault outage (hr/fault) | Duration per maintenance outage (hr/annum) |
| 132 kV overhead line | 0.67 | - | 1.25 | 30.2 |
| 275 kV overhead line | 0.12 | - | 13.06 | 14.4 |
| 275 kV underground cable | 0.20 | - | 2016 | 8 |
| Low-rated connection-point transformer | - | 0.05 | 192 | 8 |
| High-rated connection-point transformer | - | 0.05 | 1344 | 8 |

When applying the failure rates in Table 2, it was assumed that single supply lines are maintained through live line techniques to minimise supply outages to radial connection points. It has also been assumed that single supply lines have zero annual maintenance outage hours.

Under these failure rates, the expected hours of unserved energy (and the reliability level) at each connection point was derived by combining the expected outage hours of each supply line and transformer. Parallel lines and transformers with sufficient capacity reduce the expected unserved energy as each parallel element adds an additional level of redundancy, increasing the level of supply reliability at the connection point. Conversely, series elements, such as a single transformer at the end of a transmission line, reduce the level of reliability as loss of either series element results in loss of supply to the connection point.

The data in Table 2 also shows that overhead transmission lines are highly reliability with very few outage hours expected in any one year. Due to the high reliability of these lines, terminal stations connected by four or more transmission lines, such as Para, Davenport, and Robertstown, are expected to be particularly reliable supply points. The probability of having three or more concurrent line outages is very low, and these supply points are therefore almost always expected to be capable of supplying power to the local transmission network.

It is therefore the reliability, or level of redundancy, of the transmission network directly supplying a connection point that predominately determines the overall connection point reliability. Probabilistically, these highly reliable supply points are expected to contribute negligible unserved energy, with the majority of unserved energy being caused by the network connecting these supply points to the connection point.

Table 2 shows that, where 'n' is the line number, for a 100 km, 275 kV overhead transmission line, the probability of a:

- forced outage, Pr{Fn}, is (0.12 x 13.06) hrs/annum or 1.5672 / 8760, and
- planned outage, Pr{Pn}, is 14.4 hrs/annum or 14.4/8,760.

Table 3 lists the reliability theory the assessment applied, and demonstrates the high reliability and negligible expected unserved energy from having multiple parallel transmission lines.

*Table 3 – Reliability Theory*

| Transmission element | Reliability theory | Outage duration of 275 kV lines (hours/annum/100 km length) | Availability rate |
|---|---|---|---|
| Single line | Pr{F1} | 1.5672 | 99.98211% |
| Two parallel lines | Pr{F1} Pr{F2} +<br>Pr{P1} Pr{F2} +<br>Pr{F1} Pr{P2} | 5.4328E-03 | 99.99994% |
| Three parallel lines | Pr{F1} Pr{F2} Pr{F3} +<br>Pr{P1} Pr{F2} Pr{F3} +<br>Pr{F1} Pr{P2} Pr{F3} +<br>Pr{F1} Pr{F2} Pr{P3} | 1.4329E-06 | >99.99999% |
| Four parallel lines | Pr{F1} Pr{F2} Pr{F3} Pr{F4} +<br>Pr{P1} Pr{F2} Pr{F3} Pr{F4} +<br>Pr{F1} Pr{P2} Pr{F3} Pr{F4} +<br>Pr{F1} Pr{F2} Pr{P3} Pr{F4} +<br>Pr{F1} Pr{F2} Pr{F3} Pr{P4} | 3.3880E-10 | >99.99999% |

Based on the supporting information in Table 3, and to simplify the assessments without introducing significant errors, highly reliable terminal stations with four or more connecting transmission lines have been used as reference points, and the reliability of each connection point was based on the transmission plant reliability between these supply points and each connection point.

### 4.2.3 Value of customer reliability

The value of customer reliability (VCR) is a measure of a reliable electricity supply's value to society, or alternatively, a measure of the cost to society of unserved energy.

The VCR is used in probabilistic transmission planning approaches to value changes in unserved energy that occur under alternative augmentation options.

A set of VCR numbers has been produced for the Victorian region. These measures were originally estimated by Monash University (1997)[7], using direct survey methods. The Monash University work was updated twice by Charles River Associates (CRA) (2002[8], 2008[9]) and is indexed to

[7] Dr M.E. Khan and Dr M. F. Conlon (1997), *Value of Lost Load,* Centre for Electrical Power Engineering (CEPE),Department of Electrical and Computer Systems Engineering, Monash University, for the Victoria Power Exchange (VPX)

[8] Charles River Associates (2002), *Assessment of the Value of Customer Reliability (VCR)*, http://www.aemo.com.au/planning/0409-0001.pdf

Victorian income measures between surveys[10]. Indexation ensures that the values are updated annually to reflect current income growth and consumption shares for identified economic sectors (agricultural, industrial, commercial, and residential).

In 2010, AEMO undertook to develop VCR estimates for each region, using existing Victorian survey data to calculate VCRs for regions other than Victoria. A draft report by Oakley Greenwood has been published on the AEMO website, which includes a demonstration of each region's VCR calculation[11].

The method used by Oakley Greenwood involved combining the sectoral VCRs determined in the 2007 Victorian VCR study with region-specific data from the other regions (involving the number and duration of outages experienced over the past several years), and the volume of consumption within each identified economic sector used in the VCR.

The 2007 VCR for each sector and each region were then updated to 2010 values using the indexation method.

The regional data on outages and sector consumption were provided by the distribution network service providers (DNSPs) within each region.

The VCR developed for South Australia by Oakley Greenwood was $45,767 (in 2010 Australian dollars), and was used by AEMO as a base value in this report. The sensitivity analysis for this VCR applied values of $38,240 and $53,295 (in 2010 Australian dollars)[12].

### 4.2.4 Transmission upgrade costs

Transmission augmentation projects, were nominated by ElectraNet. These augmentation projects and the associated transmission costs are outlined in ElectraNet's Annual Planning Report. Where included, additional distribution costs were provided by ETSA Utilities, based on recent connection cost estimates obtained for similar projects.

Sensitivity analysis was performed with variations of $\underline{+}$30% on these cost estimates.

A comparison of the transmission augmentation costs supplied by ElectraNet and the costs used by AEMO when undertaking its planning functions found the two to be reasonably consistent.

### 4.2.5 Economic assumptions

The cost-benefit assessment was performed for the period from 2010/11-2029/30. Based on information provided by ElectraNet for the purpose of the cost-benefit assessment, a new transformer was assumed to have an asset life of 45 years, and a new transmission line or underground cable was assumed to have an asset life of 55 years.

The annual payments resulting from each investment were calculated using the appropriate asset life and an assumed real discount rate of 10% (for the base case), with sensitivities of 7% and 13%. These assumptions are consistent with the RIT-T, which specifies that the assessment must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector.

The RIT-T also suggests that the sensitivity testing should be performed with the lower bound being the AER mandated regulatory real pre-tax weighted average cost of capital (WACC) for transmission investments.

The annual capital costs payments and the costs of unserved energy were discounted to a net present value using the same discount rates (and sensitivities). A terminal value approach was

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[9] Charles River Associates (2008), *Assessment of the Value of Customer Reliability (VCR)*, http://www.aemo.com.au/planning/0409-0002.pdf

[10] VENCorp (2009), *Methodology for Extrapolating VCR between Surveys for 2008/09 to 2011/12*, http://www.aemo.com.au/planning/0400-0007.pdf

[11] Oakley Greenwood (2010), *Valuing Reliability in the National Electricity Market*, http://www.aemo.com.au/planning/0409-0003.pdf.

[12] For information about calculation of the VCR sensitivity values, see Appendix 0.

used to reflect the value of the capital expenditure and the unserved energy at the end of the assessment period (2029/30). To calculate the terminal value it was assumed that the last year's unserved energy costs continued in perpetuity.

# 5 Specific Connection Point Categorisation

AEMO's economic assessment identified that upgrading the reliability of supply at both the Baroota and Dalrymple connection points from Category 1 to Category 2, is economically appropriate within ElectraNet's upcoming regulatory period (2013-2018).

When assessing the value of expected unserved energy on a probabilistic basis, these two connection points showed a positive net present value based on the capital cost estimates to install a new supply transformer at each connection point.

In addition, AEMO has recommended changes to Category 5 and Category 6 to clarify the supply requirements to Adelaide Central and Adelaide's surrounding suburbs.

The full cost-benefit assessment results supporting each recommendation are included in Appendix F. Sensitivities to the base assumptions are included in Appendix B.

## 5.1 Supply to Baroota and Dalrymple

Baroota and Dalrymple are among the few remaining Category 1 connection points (other than small pumping station loads and remote mining sites).

Baroota has a forecast maximum demand of approximately 10 MW, and Dalrymple has a forecast maximum demand of approximately 12 MW.

Each connection point's assessment shows that installing an additional connection point transformer is economically justifiable. Each installation requires both transmission and distribution works.

### 5.1.1 Baroota

The estimated capital cost to install a new transformer at Baroota is $22 million, comprising ElectraNet's $14 million transmission works (with supply of the transformer), and ETSA Utilities' associated $8 million distribution works.

The expected unserved energy at the Baroota connection in 2017/18 is approximately 103 MWh. With the installation of a second transformer at Baroota, the expected unserved energy decreases to approximately 7 MWh, resulting in savings of almost $4.4 million from the unserved energy avoided in this year alone.

In addition to the transmission lines and connection point transformers supplying the Baroota connection point, a 33 kV sub-transmission network can also connect Baroota to the Bungama connection point. This sub-transmission network connection is operated in a normally open configuration, where Baroota demand is normally disconnected from the rest of the 33 kV sub-transmission network.

Although the sub-transmission network can be closed to support Baroota demand during a transmission outage, ETSA Utilities advises that this may not be possible during peak demand periods due to excessive network voltages. Additionally, the sub-transmission network is not capable of supplying the entire forecast demand and can only partially be changed over automatically, with the majority of the Baroota network relying on manual fault finding and restoration, typically taking up to four hours.

As a result, and due to the higher expected outage rate of the 33 kV sub-transmission network, demand support via sub-transmission is estimated to provide negligible benefits. However, sub-transmission network upgrades should still be considered to meet the Category 2 reliability level, as this may be more cost-effective than installing a second connection point transformer.

### 5.1.2 Dalrymple

Dalrymple requires a capacitor bank installation during the 2013-2018 regulatory period, resulting in only a modest incremental cost for the new transformer installation. As a result, the estimated capital cost to install a new transformer at Dalrymple is $15 million, comprising ElectraNet's $7 million transmission works (with supply of the transformer), and ETSA Utilities' associated $8 million distribution works.

The expected unserved energy at the Dalrymple connection point in 2016/17 is approximately 128 MWh. With the installation of a second transformer at Dalrymple, the expected unserved energy decreases to approximately 12 MWh, resulting in savings of more than $5.3 million of unserved energy avoided in this year alone.

### 5.1.3 Recommendation

Table 4 and Table 5 show the benefits from installing additional transformers at Baroota and Dalrymple within the 2013-2018 regulatory period.

*Table 4 – Baroota Economic Assessment*

| Reliability standard category | 2017/18 forecast demand (MW) | Expected unserved energy (MWh/annum) | Annual cost of unserved energy ($USE) |
|---|---|---|---|
| Category 1 | 10.0 | 103 | $4,548,000 |
| Category 2 | 10.0 | 7 | $163,000 |
| | Annual Benefits in 2017/18 | | $4,385,000 |
| | NPV net benefits of augmentation (over 45 year project life) | | $13,263,000 |

*Table 5 – Dalrymple Economic Assessment*

| Reliability standard category | 2016/17 forecast demand (MW) | Expected unserved energy (MWh/annum) | Annual cost of unserved energy ($USE) |
|---|---|---|---|
| Category 1 | 12.1 | 128 | $5,615,000 |
| Category 2 | 12.1 | 12 | $310,000 |
| | Annual Benefits in 2016/17 | | $5,305,000 |
| | NPV net benefits of augmentation (over 45 year project life) | | $27,743,000 |

Appendix D shows sensitivities to VCR, discount rate and augmentation costs, while Appendix F shows detailed connection point assessments for these and other connection points.

With the Baroota and Dalrymple installations demonstrating positive net economic benefits of approximately $13 million and $28 million (respectively) over the life of the assets, AEMO recommends moving each connection point to the Category 2 reliability standard.

To allow sufficient time for ElectraNet to complete works and to align with ETSA Utilities' regulatory period commencing in 2015, AEMO recommends that timing of the Baroota and Dalrymple connection point reclassification should be staged. The effective reclassification dates are included in the next revision of the ETC with the dates outlined as follows:

- Baroota reclassified to Category 2 effective from 1 December 2017.
- Dalrymple reclassified to Category 2 effective from 1 December 2016.

## 5.2 Category 5 connection points

The Adelaide eastern suburbs connection points of Dry Creek East, Magill (east), and Northfield are Category 5 connection points. They currently have a higher reliability standard than the southern, northern, and western suburbs because they form part of the meshed network supplying Adelaide Central, including the Adelaide central business district.

The reliability at Category 5 connection points is defined by an equation based on demand at the connection point as well as the demand within Adelaide Central (for more information, see Section 6.2). This equation was part of the ETC prior to the establishment of Category 6, and AEMO understands that the equation was intended to represent the requirement for an increased reliability standard in Adelaide Central rather than in the Eastern suburbs themselves.

The previous ETC review established Category 6, which includes the existing East Terrace and the future City West (to be commissioned by 31 December 2011) connection points, which directly serve Adelaide Central, with the intention of defining Adelaide Central's current and future reliability. However, the previous review retained Category 5, primarily to cover the time until establishment of the new connection point.

AEMO recommends that the connection points in Category 5 (Dry Creek East, Magill (east), and Northfield) be moved to Category 4, and that the current Category 5 be removed from the ETC.

Although the current Category 5 connection points (Dry Creek East, Magill (east), and Northfield) may currently have adequate line and transformer capacity to supply Adelaide Central, through either the transmission or distribution system, even if two lines or transformers fail (this may involve some load shedding in the Eastern suburbs), AEMO believes that the requirement for Adelaide Central reliability is better expressed by Category 6.

## 5.3 Category 6 connection points

With the recommendation to move Category 5 connection points to Category 4, and the subsequent removal of the current Category 5, AEMO recommends that Category 6 be re-named Category 5.

## 5.4 Connection point recommendation summary

Table 6 lists the allocation of connection points to categories as per the recommendations already discussed, including the addition of Munno Para to the Para and Parafield Gardens West grouped connection point.

*Table 6 – Allocation of connection points to categories*

| Category | Connection point | |
|---|---|---|
| Category 1 | • Baroota (until 1 December 2017)<br>• Dalrymple (until 1 December 2016)<br>• Florieton SWER<br>• Kanmantoo Mine<br>• Leigh Creek Coal*<br>• Leigh Creek South<br>• Mannum/Adelaide 1*<br>• Mannum/Adelaide 2*<br>• Mannum/Adelaide 3*<br>• Middleback*<br>• Morgan/Whyalla 1*<br>• Morgan/Whyalla 2*<br>• Morgan/Whyalla 3*<br>• Morgan/Whyalla 4* | • Mt Gunson<br>• Murray/Hahndorf 1*<br>• Murray/Hahndorf 2*<br>• Murray/Hahndorf 3*<br>• Neuroodla<br>• Roseworthy*<br>• Stony Point (Whyalla Refiners) – distribution<br>• Stony Point*<br>• Whyalla LMF<br>• Davenport*<br>• Pimba*<br>• Woomera*<br>*denotes a customer but does not include a distributor |
| Category 2 | • Ardrossan West<br>• Baroota (on and from 1 December 2017)<br>• Dalrymple (on and from 1 December 2016) | • Kadina East<br>• Wudinna<br>• Yadnarie |
| Category 3 | • Port Lincoln | • Snuggery Rural |
| Category 4 | • Angas Creek<br>• Berri/Monash<br>• Blanche<br>• Brinkworth<br>• [Bungama and Pt Pirie]<br>• Clare North<br>• Coonalpyn West<br>• Dorrien<br>• Templers<br>• Hummocks<br>• Keith<br>• Kincraig<br>• Mannum<br>• Mobilong | • Mt Barker<br>• Mt Gambier<br>• North West Bend<br>• Playford (Davenport West)<br>• Snuggery Industrial<br>• Tailem Bend<br>• Waterloo<br>• Whyalla Terminal – Main Bus<br>• Penola West<br>• [Dry Creek West, Kilburn, LeFevre, New Osborne and Torrens Island 66 kV]<br>• [Happy Valley, Magill (South) and Morphett Vale East]<br>• [Para, Munno Para and Parafield Gardens West]<br>• [Dry Creek East, Magill (East) and Northfield] |
| Category 5 | • Adelaide Central [East Tce, City West] | |

# 6 Proposed Amendments to the ETC

This Section 6 outlines AEMO's proposed amendments to the ETC. Proposed wording amendments are included to explain the context of the amendments. Proposed new wording is presented in red text colour to assist the reader in identifying the proposed amendments.

## 6.1 Timeframe to remedy connection point reliability breaches

ElectraNet's planning to meet the reliability standards is based on contracted agreed maximum demand. AEMO has been advised that agreed maximum demand is contracted on a 12-month forecast, providing limited opportunity for planning.

As most augmentations have a lead time in excess of 24 months, it is inevitable that the reliability standard will rarely be achieved within the 12-month best endeavours period allowable to rectify a breach in the reliability standards under the ETC. ElectraNet also advises it has experienced difficulty in receiving regulated funding to complete augmentations within the 12-month best endeavours period due to the allowance in the ETC for ElectraNet to rectify such a breach within a 3-year period.

Clause 6.3.1 of the ETC goes some way to reducing the likely period of breach by placing a best endeavours obligation on the transmission entity to obtain planning approvals and acquire easements based on forecasts, prior to agreed maximum demand breaching the required reliability standard.

Due to the difficulties in contracting agreed maximum demand beyond a 12-month forecast, AEMO recommends that clause 6.3.1 should be expanded to include forecast agreed maximum demand and a best endeavours obligation on the transmission entity to complete all necessary design work, outlined as follows:

> *6.3.1. A **transmission entity** must use its **best endeavours** to complete all necessary design work, obtain all necessary planning approvals and acquire all necessary land and easements on the basis of forecast demand prior to **forecast agreed maximum demand** breaching the reliability standards in this industry code so as to ensure they are in a position to meet their obligations.*

In line with this recommendation, AEMO also proposes wording for a new definition to be included in the section 10.1, Definitions of the ETC, outlined as follows:

> ***10.1 Definitions***
>
> ***Forecast agreed maximum demand** means the **agreed maximum demand** forecast for a given year that is provided by the customer three years prior to when the **agreed maximum demand** is contracted.*

AEMO considers that the proposed amendments to clause 6.3.1 will go some way toward reducing any breach period and that the 3-year grace period should be removed from the ETC to ensure a clearer application of the 12-month best endeavours obligation to rectify any breach. In moving the 3-year obligation to a 12-month obligation, AEMO assumes that any force majeure or similar exceptions under the previous arrangements will continue to apply.

This proposed amendment will require changes to each of clauses 2.6.3, 2.7.3, 2.8.3, 2.9.3 and 2.10.3, demonstrated as follows:

> *2.6.3. In the event that **forecast agreed maximum demand** at a **connection point** or group of **connection points** exceeds the **equivalent transformer capacity** standard required by this clause 2.6, a **transmission entity** must:*
>
> *(a) ~~use its **best endeavours** to~~ ensure that the **equivalent transformer capacity** at the **connection point** or group of **connection points** meets the required standard within 12 months~~; and~~*
>
> *~~(b) ensure that the **equivalent transformer capacity** at the **connection point** or group of **connection points** meets the required standard within 3 years.~~*

To avoid breach issues arising due to the eventual contracted agreed maximum demand exceeding the forecast agreed maximum demand (as a result of drop-in customer spikes and other unanticipated increases in demand that have not been included in the forecast demand), AEMO recommends including the following additional clause that allows such a breach to be remedied within 3 years rather than 12 months:

> *6.3.2. A **transmission entity** must ensure a breach in the reliability standard is remedied within 12 months of the **forecast agreed maximum demand** exceeding the reliability standard. In the case of a breach not appearing in the **forecast agreed maximum demand** prepared 3 years prior, such breach is excluded from the 12 month obligation and the **transmission entity** must use its **best endeavours** to remedy the breach within 12 months from the time of the breach and must, in any case, remedy the breach within three years from the time of breach.*

## 6.2 Supply to Adelaide Central and surrounding suburbs

Under the current ETC, Category 5 and Category 6 contain grouped connection points that, together with ETSA Utilities' meshed sub-transmission network, supply Adelaide Central and surrounding suburbs.

### 6.2.1 Current Code

AEMO understands that the ETC's original intent was to deliver highly reliable supply to Adelaide Central and Adelaide's surrounding suburbs, as follows:

- N-1 to Adelaide Central, without interruption.
- N-1 to Adelaide's surrounding suburbs, without interruption.
- N-2 to Adelaide Central, after some interruption to allow for post contingent operation.

The existing Category 5 effectively specifies that the transmission entity must provide transmission line capacity and transformer capacity, shared across the grouped connection points, as follows:

- N-1 equivalent capacity for 100% of agreed maximum demand equal to that of Adelaide's surrounding eastern suburbs' load (obligation via Category 5).
- N-1 equivalent capacity for 100% of agreed maximum demand equal to that of Adelaide Central's load (obligation via Category 5 and 6).
- N-2 equivalent capacity for 50% of agreed maximum demand equal to that of Adelaide's surrounding eastern suburbs' load (obligation via Category 5).
- N-2 equivalent capacity for 100% of agreed maximum demand equal to that of Adelaide Central's load (obligation via Category 5).

Category 5's required level of reliability is shared across a group of transmission connection points that include Dry Creek East, Magill (east), and Northfield. This excludes the main Adelaide Central supply point of East Terrace as well as the future City West transmission connection point.

The reliability standards under Category 5 reflect the network situation as it currently is, in that there is some inherent N-2 capacity in Adelaide Central via ETSA Utilities' network (after switching), although this capacity is expected to decrease over time. The current ETC includes no obligation to ensure that Category 5 connection points deliver N-2 capacity to Adelaide Central (only that they have that capacity). As a result, there appears to be no guarantee that increasing the reliability in Category 5 ensures higher Adelaide Central supplies.

AEMO also understands that the code can be interpreted in practice to mean that up to 50% of the eastern suburbs load can be sacrificed in order to supply N-2 capacity to Adelaide Central.

### 6.2.2 Clarification of Intent

AEMO recommends amendment of the ETC so that its intent is more explicit, and so that it clearly states that the N-2 capacity must be able to be supplied to Adelaide Central.

In summary, AEMO recommends that Category 5 and Category 6 be re-worded to explicitly state the intention to provide:

- N-1 capacity to Adelaide Central without interruption
- interruptible N-2 capacity to Adelaide Central from a combination of Adelaide Central and outer suburban connection points (and supporting distribution networks), and
- N-1 capacity to the suburbs surrounding Adelaide Central.

The provision of an interruptible N-2 supply to Adelaide Central is not intended to alter the existing reliability standard's intent, but to clarify the ETC requirement to provide this level of reliability to Adelaide Central.

To achieve this, AEMO recommends:

- the current Category 5 be removed and its connection points moved to Category 4, with Category 6 to be re-named Category 5, and include only the connection points currently in Category 6 (East Tce and the new City West substation), and
- rewording the new Category 5 to include an ETC requirement having an N-1 and interruptible N-2 reliability standard to Adelaide Central through the combined connection of the East Terrace and City West connection points.

AEMO also recommends that this reliability level should be met using both the new Category 5 connection points (East Tce and City West) and any combination of connection points in Category 4 and the supporting sub-transmission network.

AEMO's proposed wording for the new Category 5 is outlined as follows:

*For **transmission line** capacity, a **transmission entity** must:*

*(a) provide **N-1 equivalent line capacity** for at least 100% of **agreed maximum demand**;*

*(b) provide **N-2 equivalent line capacity** such that at least 100% of **agreed maximum demand** can be met through post-contingent operation;*

> *(i) under **N-2** contingency events use its **best endeavours** to restore supply within one hour of the interruption;*
>
> *(ii) use its **best endeavours** to restore **equivalent line capacity** within 4 hours of an interruption.*

*The capacity under clauses (a) and (b) can be provided by connection points in category 4 or 5. Under **N-2** contingency events load may be shed at category 4 connection points to fulfil clause (b) obligations.*

*For **transformer** capacity, a **transmission entity** must:*

*(a) provide **N-1 equivalent transformer capacity** for at least 100% of **agreed maximum demand**;*

*(b) provide **N-2 equivalent transformer capacity** such that at least 100% of **agreed maximum demand** can be met through post-contingent operation;*

> *(i) under **N-2** contingency events use its **best endeavours** to restore supply within one hour of an interruption.*

*The capacity under clauses (a) and (b) can be provided by connection points in category 4 or 5. Under **N-2** contingency events load may be shed at category 4 connection points to fulfil clause (b) obligations.*

To allow the reliability to be delivered by connection points within the specified category as well as from connection points within other sub-transmission connected categories, transmission and sub-transmission network designs must be jointly planned.

### 6.2.3 Recommendation for Regulatory Investment Test

AEMO is aware that clarification of the ETC's intent, as outlined in Section 6.2.2, will place additional obligations on ElectraNet and ETSA Utilities, as the ability of ETSA Utilities' distribution network to provide capacity to Adelaide Central will diminish as demand increases. AEMO recommends that, prior to any ETC amendments being finalised, ElectraNet and ETSA Utilities should undertake a full Regulatory Investment Test to identify if the additional obligations can be met economically.

### 6.2.4 Joint Planning

In addition to the NER obligations for joint planning, AEMO proposes that a new clause be included under Section 6 of the ETC, outlined as follows:

**6.4 Joint Planning**

*6.4.1 Where the most economically feasible option to meet the reliability standards of clauses 2.5 to 2.10 relies on a combination of transmission and sub-transmission then the **transmission entity** must ensure that the reliability required by that category is capable of being delivered to the **agreed maximum demand** points within that category, including for any contingency events that the category requires for that reliability category.*

The addition of this new clause places an overall responsibility on ElectraNet to ensure that the defined reliability standards can be delivered, in conjunction with both ElectraNet's and ETSA Utilities' NER joint planning obligations.

The outcome of allowing the reliability standards for Adelaide Central loads (proposed Category 5) to be met using connection points in Category 4 may be that these connection points will be upgraded to higher reliability standards than those specified in Category 4.

To account for this outcome, AEMO recommends that the ETC reliability standards be clarified as minimum standards.

As such, AEMO recommends a new clause 2.3.2:

> *2.3.2. The reliability standards set out in clauses 2.5 to 2.10 are minimum standards and if the **transmission entity** undertakes cost-benefit planning and can demonstrate positive economic benefits these standards do not limit the **transmission entity** from increasing overall reliability, including at connection points or grouped connection points in reliability categories other than that being upgraded.*

## 6.3 Limitation on supply from non-network support

As the ETC is presently written, to meet the reliability standards of each category, the agreed maximum demand must not exceed 100% of line capacity or 100% of transformer capacity or, in the case of Category 1, 2 and 3, where appropriate network support arrangements are in place, 120% of line or transformer capacity.

Limiting the agreed maximum demand based on network capability, however, may require transmission network augmentation even if reliable local non-network support is available and is a more cost-efficient supply option.

AEMO considers that the amount of supply that can be provided from network support arrangements or non-network support options should be based on the reliability and economics of utilising non-network support when compared with augmenting the transmission network.

For example, if there is sufficient reliable generation that is more cost effective to operate than to augment the transmission network, then the amount of agreed maximum demand should not be limited based on transmission network capacity.

As such, AEMO recommends the removal of clauses 2.5.1 (a), 2.5.2 (a), 2.6.1 (a), 2.6.2 (a), 2.7.1 (a), 2.7.2 (a), 2.8.1 (a), 2.8.2 (a), 2.9.1 (a), 2.9.2 (a), 2.10.1 (a) and 2.10.2 (a) from the ETC, leaving the transmission entity to provide equivalent line capacity, as shown by the following example:

> *2.6.1. For **transmission line** capacity, a **transmission entity** must:*
>
> ~~*(a) not contract for an amount of **agreed maximum demand** greater than:*~~
>
> ~~*(i) 100% of installed **transmission line** capacity ; or*~~
>
> ~~*(ii) where the **transmission entity** has appropriate **network support arrangements** in place, 120% of installed **transmission line** capacity;*~~
>
> *(b) provide **equivalent line capacity** for at least 100% of contracted **agreed maximum demand**.*

To ensure the proposed amendments do not lead to a reduction in the level of reliability, or to undue reliability obligations on generators that are only contracted to provide supply during peak periods, AEMO also proposes the following amendments and new clauses in place of the existing :

*2.11.1 In providing **equivalent transmission line** capacity or **equivalent transformer** capacity for the purposes of this Chapter 2 by means of a **network support arrangement** a **transmission entity** must:*

*(a) In the case of network support arrangements providing up to 20% of **agreed maximum demand**, ensure that the **network support arrangement** delivers the required **equivalent line capacity** or **equivalent transformer capacity** within the prescribed timeframe on at least 95% of occasions on which it is sought to be utilised within any 12 month period ending on 30 June.*

*(b) In the case of a **network support arrangement** providing above 20% of **agreed maximum demand**, ensure that the **network support arrangement** delivers the equivalent level of reliability that could reasonably be expected from a transmission network option.*

*2.11.2. Where the required reliability level or supply capability relies on a **network support arrangement**, the **transmission entity** should ensure the capability and availability of the **network support arrangement** by entering into a network support agreement with each network support provider.*

The proposed amendments allow the reliability of network support arrangements to be lower if they are only in place for peak shaving requirements. However, if the network support arrangement is in place to supply a higher proportion of the demand it is required to have an equivalent level of reliability that would be expected from a transmission network option.

To achieve an equivalent level of reliability from network support arrangements, as can reasonably be expected from a transmission network option, it is anticipated that the network support options will require additional levels of redundancy.

For example, if local generation is used to provide network support to meet the required reliability standard, based on the following outage rates, one generator unit is insufficient to match the reliability of a 132 kV transmission line installation. However, having a second generator unit in parallel provides the additional level of reliability required to make it a more reliable option than installing the new transmission line.

*Table 7 – Example plant outage rates*

| Plant | Outage rate (%) |
|---|---|
| Outage rate per generator unit | 5.00% |
| Equivalent outage rate of two parallel generator units[13] | 0.25% |
| Outage rate of 100 km long 132 kV transmission line, with planned outages | 0.35% |

In the case of a single supply line, if operating the two generator units pre-contingent to secure supply for loss of a transmission element proves more economically viable than installing a new transmission line, then ElectraNet should explore entering into a network support arrangement with the generator to have them operate their generation to match demand.

[13] The two unit failure rate is for illustration only, and assumes that the failure modes of the two generating units are independent and there are no common failure modes. In reality this is unlikely, particularly for small generating systems, due to common plant items such as auxiliary supply, fuel lines etc.

To ensure that the network support arrangement provides the required level of reliability, it is anticipated that a network support agreement will include, but not be limited to, the following information:

- Agreed supply capacity.
- Generator start-up rates, where the network support arrangements are operated post-contingent.
- Generator start-up costs.
- Short-run marginal costs.
- Forced outage rates per annum.
- Planned outage rates per annum.

In support of the proposed ETC amendments, AEMO considers that limiting the supply that can be provided by network support arrangements potentially conflicts with the NER's intent, in which non-network options must be considered as alternatives to network augmentation. The proposed amendments are considered to be consistent with the intent of the NER.

## 6.4 Murraylink capability and assessment of reliability standards

Transfer from Victoria to South Australia via the Murraylink interconnector is determined by limitations in regions other than just South Australia, such as voltage stability and thermal line constraints in Victoria. The design transfer capability of 220 MW is based on a Victorian demand of 9,600 MW. This transfer capability decreases by approximately 5 MW per 100 MW increase in Victorian demand above 9,600 MW.

When assessing the reliability level of loads in the Riverland region, AEMO recommends that the supply capability from Murraylink should be calculated by using the Murraylink transfer limit equation and assuming worst-case peak-demand conditions, including applying the Victorian maximum demand forecast (that is, applying the 10% probability of exceedence, or one-in-ten-year forecast maximum demand under a medium economic growth scenario for the year of interest).

As Murraylink's power transfer capability is constrained by Victorian limitations and depends on generation from other regions, AEMO considers it appropriate for ElectraNet to approach other TNSPs to undertake joint planning to identify the most economically viable solution to meet their reliability standards.

As outlined in Section 6.2, the inclusion of a new clause on joint planning promotes identification of the most economically viable solution, regardless of whether that solution requires augmentation to ElectraNet's transmission network, installation of new generation, augmentation of ETSA Utilities' distribution or sub-transmission network, or augmentation in another region.

A further extension to this new clause helps clarify the treatment of Murraylink capability and to ensure that contingencies in networks other than ElectraNet's transmission system are considered in meeting the reliability standards. This is included as contingencies in the sub-transmission network or other regions can potentially have a higher impact on supply capability than outages on ElectraNet's transmission network. The additional sub-clauses under the new joint planning clause are as follows:

> *6.4.2. A **transmission entity** which provides **equivalent transmission line capacity** or **equivalent transformer capacity** for the purposes of Chapter 2 must consider network plant failures in any NEM region, including distribution systems, where such plant failures might impact on the applicable level of redundancy or reliability.*

*6.4.3. For the purpose of assessing **connection point** reliability, the capability of the Murraylink interconnector should be calculated using the Murraylink transfer limit equation under peak Victorian demand conditions.*

## 6.5 Clarification that category 3 loads have an interruptible N-1 reliability level

AEMO understands that the intention of Category 3 is that N-1 supply is provided, but that it can be delivered by post-contingent operation after a temporary load interruption. Without altering obligations under the existing ETC Category 3 reliability standards, AEMO recommends that clause 2.7.1 (b) and 2.7.2 (b) be expanded to further clarify the intent, and confirm that Category 3 loads do not require an N-1 supply on a firm, uninterruptable, basis.

As a result, AEMO proposes the expansion of clause 2.7.1 (b) and 2.7.2 (b) to include the phrase “through post-contingent operation” as follows:

*2.7.1.*

*(b) provide **equivalent line capacity** such that at least 100% of **agreed maximum demand** can be met, through post-contingent operation, following the failure of any relevant **transmission line** or **network support arrangement**;*

*...*

*2.7.2.*

*(b) provide **equivalent transformer capacity** such that at least 100% of **agreed maximum demand** can be met, through post-contingent operation, following the failure of any installed **transformer** or **network support arrangement**;*

*...*

## 6.6 Quality of supply and system reliability

Clause 2.1.1 and 2.1.2 are concerned with the quality of supply and system reliability, and require ElectraNet to not shed load and to minimise the likelihood of load shedding, respectively, in developing and operating the transmission network and transmission system.

Although it is understood that these clauses relate to the quality of transmission services, rather than the ETC reliability standards, AEMO believes that these clauses can potentially be misinterpreted to contradict the reliability standards defined in the ETC.

To clarify the intent of the ETC, AEMO recommends that clauses 2.1.1 and 2.1.2 be modified to be subject to the clause 2 reliability standards, as follows:

2.1.1. Subject to the service standards specified in this clause 2, a ***transmission entity*** must use its ***best endeavours*** to plan, develop and operate the ***transmission network*** to meet the standards imposed by the ***National Electricity Rules*** in relation to the quality of ***transmission services*** such that there will be no requirements to shed load to achieve these standards under normal and reasonably foreseeable operating conditions.

2.1.2. Subject to the service standards specified in this clause 2, a ***transmission entity*** must use its ***best endeavours*** to plan, develop and operate the ***transmission system*** so as to meet the standards imposed by the ***National Electricity Rules*** in relation to ***transmission network*** reliability such that there will be minimal requirements to shed load under normal and reasonably foreseeable operating conditions.

## 6.7 New connection points

Clause 2.12 of the ETC outlines ElectraNet's approval process for establishing new connection point's.

Consistent with AEMO's understanding of the intent of the transmission reliability standards, AEMO recommends that the requirement to consult with ESCOSA on the establishment of new connection points be clarified so that it only applies to new transmission customer and distributor connection points, and not new generator connection points as could currently be interpreted.

To clarify the intent of the ETC, AEMO recommends that clause 2.12.1 be amended as follows:

> 2.12.1. Where a new **transmission customer** or **distributor** **connection point** is provided by a **transmission entity,** the **transmission entity** must submit the application standards for that **connection point** to the **Commission** for approval. The standards submitted must be developed having regard to:
>
> (a) any recommendations of ~~the **Planning Council**~~ AEMO;
> (b) the size of the load;
> (c) the value of lost load and types of **customers**;
> (d) the number of **customers;**
> (e) the distance from **Adelaide Central**; and
> (f) the cost of installation of transmission assets relevant to the **connection point**.

# Appendix A Additional Connection Point Studies

In additional to the Baroota and Dalrymple connection point studies, AEMO's assessment identified other connection points, including Port Lincoln and Kadina East, that are worth noting due to the large expected unserved energy and degrading connection point reliability at Port Lincoln and the specific load type at Kadina East. However, due to their relatively remote locations, the augmentations identified to increase each connection point's reliability standard are expensive.

These connection points are not recommended for category upgrades as, based on unserved energy alone, they do not provide positive cost benefits. Alternatively, they are noted for further assessment by considering a holistic cost-benefit assessment, including proposed generation and unaccounted-for new load connections, and lower-cost alternatives.

Detailed economic assessments have been included in Appendix F, to help identify the timing or amount of additional demand required to justify the proposed augmentations.

AEMO has also completed an assessment of the Fleurieu Peninsula load, which is currently supplied by ETSA Utilities' sub-transmission network, regarding an appropriate reliability standard if a new transmission connection point is found to be the most efficient solution under the Regulatory Test to supply the Fleurieu Peninsula.

## A.1 Supply to Port Lincoln

To continue to meet the existing Category 3 reliability standards applying to Port Lincoln, ElectraNet has raised concerns that major line augmentation will be required on the Eyre Peninsula by approximately 2017/18.

Alternatively, increasing the allowable level of network support, beyond the present restrictions limiting the contracted agreed maximum demand to 120% of transmission line capacity, will be required to continue meeting the existing category 3 reliability level.

ElectraNet proposed two possible network augmentation options.

Both options involve reinforcing the Eyre Peninsula, south of Cultana, by constructing a 275 kV double circuit line from Cultana to Port Lincoln, and establishing a 275/132 kV substation at Port Lincoln. At an estimated cost of $396 million, the first higher capacity option consists of twin sulphur conductors per phase with stronger support towers. This augmentation does not show positive economic benefits within the assessed forecast period, with the net present value of net benefits estimated at approximately negative $165 million over the asset's life.

The alternative option, at an estimated cost of $309 million, consists of single sulphur per phase conductors and doesn't require as strong towers. This augmentation option doesn't show positive benefits either, with net present value of net benefits calculated at approximately negative $121 million over the asset's life.

The assessment of unserved energy was based on the summation of maximum demand at Port Lincoln, Yadnarie, Wudinna and Middleback, each of which will benefit from the proposed augmentations.

Based on unserved energy alone, a maximum demand of approximately 637 MW will be required to economically justify the $309 million augmentation option, while a maximum demand of approximately 817 MW is required to economically justify the $396 million double circuit option.

The proposed 275 kV double circuit line construction is not justified on the basis of USE alone, and unless other benefits can be demonstrated, the projects are uneconomic. ElectraNet has noted that a number of proposed new connections to this area have not progressed due to the limited line capacity. A holistic view of the needs in this area is expected to show strong interest in wind generator connections, and proposed load connections that have not been included in the existing demand forecasts or considered in this assessment.

As outlined in Section 6.3, AEMO has recommended that limitations on the allowable support from network support arrangements should be removed.

It is recommended that ElectraNet continue to investigate options to meet its existing Category 3 obligations beyond 2017/18, and that these options should consider additional network support arrangements such as the local generation support currently in place. As the local generation at Port Lincoln is understood to be expensive to operate and to have on standby in case of a network outage, network support arrangements should be considered, in a Regulatory Test conducted by ElectraNet, alongside other options.

AEMO's recommendation is that Port Lincoln remain in Category 3 and that ElectraNet investigate alternative augmentation options to continue meeting its category 3 obligations beyond 2017/18.

## A.2 Supply to Kadina East

Kadina East has approximately 18 MWh of expected unserved energy in 2017/18 which, based on the headline VCR, equates to approximately $497,000 of unserved energy in 2017/18.

ElectraNet notes that this load is primarily agricultural and that a higher, sector-specific VCR may be more appropriate than the average headline value.

The Victorian agricultural VCR is heavily influenced by dairy farming, however, and is not relevant to South Australian agricultural load. To identify an appropriate agricultural VCR for South Australia will require significant further work.

As a sensitivity study, AEMO also calculated the net present value of benefits using the Victorian agricultural VCR of $109,311. This resulted in negative net benefits of approximately $26 million, compared to negative net benefits of approximately $29 million using the headline VCR of $45,767 over the 55-year life of the project (being the installation of a new transmission line at an estimated cost of $61 million). This assessment is included to show that even when using the Victorian agricultural VCR, this connection point should remain in Category 2.

As the proposed augmentation involves establishing a new line between Kadina East and Ardrossan West, some additional benefits are provided through saved unserved energy at Ardrossan West. However, the low estimated value of unserved energy at Ardrossan West results in only minimal additional benefits, insufficient to economically justify installation of the new transmission line.

AEMO's recommendation is that the Kadina East connection point remains in Category 2.

## A.3 Fleurieu Peninsula

ETSA Utilities has identified that the capacity of the electrical supply system to the Fleurieu Peninsula is nearing its limits, and a major augmentation will soon be required to maintain local voltage levels and reliable supply to ETSA Utilities' customers.

AEMO notes that ETSA Utilities, along with ElectraNet, will be required to undertake a joint Regulatory Test assessment in order to identify the most efficient option for this region.

However, one augmentation option that has been identified is the establishment of a new transmission connection point to supply the Fleurieu Peninsula, which includes establishing a 275 kV switching station at Kanmantoo North, construction of a 275 kV double circuit line from Kanmantoo North to the Fleurieu Peninsula, and 275/66 kV transformation at the Fleurieu Peninsula connection point.

The transmission network augmentation costs associated with this option are estimated to be $243 million. These costs exclude distribution network augmentation costs, which have not yet been provided.

AEMO has calculated the level of reliability that it considers economically suitable if a transmission option is selected to service the growing Fleurieu Peninsula load.

Demand forecasts for the Fleurieu Peninsula were obtained from the ElectraNet and ETSA Utilities joint request for proposals: Projected Distribution Network Constraint: Bulk Electricity Supply to the Fleurieu Peninsula[14]. The report shows that the Fleurieu Peninsula maximum demand is 79 MW in 2010/11, and is forecast to grow steadily at approximately 5-6% per annum.

The estimated unserved energy has been calculated by assuming an asset life of 55 years, a Kanmantoo North reliability level equal to that of Tailem bend, which is considered to be close to 100% reliable, and a supply line length of 65 km between Kanmantoo North and the proposed Fleurieu Peninsula connection point.

Based on the $243 million augmentation, the assessment shows that a Category 4, N-1 reliability standard provides a net present value of benefits of approximately $2,947 million over the life of the asset.

Inclusion of this assessment has been discussed with ESCOSA, ElectraNet, and ETSA Utilities and is provided here for information only. Prior to its establishment and inclusion in the ETC, a new connection will still need to be considered through the normal process set out in the Clause 2.12 of the ETC.

AEMO recommends that ETSA Utilities and ElectraNet continue to undertake a joint Regulatory Test assessment in order to identify the most efficient option for this region.

## A.4 Supply to other connection points

In undertaking its probabilistic cost-benefit assessment of connection point reliability, AEMO started with a high level assessment of each connection point's expected unserved energy in 2017/18, the final year covered by ElectraNet's upcoming revenue reset period. From this high level assessment, connection points with a large amount of expected unserved energy where investigated in detail.

*Table 8*, on the next page, provides a summary of the high level screening studies applied at each connection point.

The summary includes the expected unserved energy in the year 2017/18 and the cost of this unserved energy. For a number of connection points it also summarises the unserved energy and cost of unserved energy, post augmentation, assuming an augmentation to increase its reliability to the next reliability category is completed.

The screening studies have been prepared using the base VCR and discount rate of $43,767/MWh and 10% respectively.

[14] etsautilities.com.au/public/redirect.jsp?id=184

*Table 8 – Summary of high level connection point reliability studies*

| Connection Point | Line one Length (km) | Line two Length (km) | Number of Parallel Transformers | 2017/18 USE (MWh/annum) | Value of Customer Load Lost ($) | 2017/18 MD Forecasts (MW) |
|---|---|---|---|---|---|---|
| Ardrossan West - N line, N-1 Tx | 43.0 | - | 2 | 8.8 | $247,808 | 18.4 |
| Ardrossan West - N-1 | 43.0 | 43.0 | 2 | 2.2 | $99,654 | 18.4 |
| Baroota - N | 82.3 | - | 1 | 102.9 | $4,548,381 | 10.0 |
| Baroota - N line, N-1 Tx | 82.3 | - | 2 | 7.2 | $163,486 | 10.0 |
| Baroota - N-1 | 82.3 | 82.3 | 2 | 0.3 | $9,803 | 10.0 |
| Dalrymple - N | 105.5 | - | 1 | 128.1 | $5,615,477 | 12.1 |
| Dalrymple - N line, N-1 Tx | 105.5 | - | 2 | 12.3 | $309,755 | 12.1 |
| Dalrymple - N-1 | 105.5 | 105.5 | 2 | 1.7 | $71,766 | 12.1 |
| Kadina East - N line, N-1 Tx | 39.6 | - | 2 | 17.6 | $497,165 | 37.6 |
| Kadina East - N-1 | 39.6 | 39.6 | 2 | 5.1 | $218,287 | 37.6 |
| Kanmantoo - N | 48.8 | - | 1 | 32.4 | $1,450,890 | 3.2 |
| Leigh Creek South - N | 250.6 | - | 2 | 3.6 | $81,061 | 1.7 |
| Mt Gunson - N | 175.9 | - | 1 | 4.8 | $203,142 | 0.4 |
| Mt Gunson - N line, N-1 Tx | 175.9 | - | 2 | 0.6 | $14,255 | 0.4 |
| Neuroodla - N | 250.6 | - | 1 | 17.7 | $599,275 | 0.9 |
| Neuroodla - N line, N-1 Tx | 250.6 | - | 2 | 1.9 | $43,168 | 0.9 |
| Neuroodla - N-1 | 250.6 | 50.0 | 2 | 0.0 | $956 | 0.9 |
| Port Lincoln - N-1 non-firm | 264.0 | - | 2 | 144.4 | $3,531,575 | 59.2 |
| Port Lincoln (option one) - N-1 firm | 264.0 | 264.0 | 2 | 15.8 | $646,495 | 59.2 |
| Snuggery Rural - N-1 non-firm | - | - | 2 | 9.2 | $409,569 | 25.7 |
| Whyalla LMF - N | - | - | 2 | 3.0 | $132,942 | 13.2 |
| Wudinna - N line, N-1 Tx | 254.0 | - | 2 | 40.7 | $998,475 | 17.4 |
| Wudinna - N-1 | 254.0 | 133.8 | 2 | 4.0 | $176,164 | 17.4 |
| Yadnarie - N line, N-1 Tx | 133.8 | - | 2 | 19.0 | $496,338 | 14.1 |
| Yadnarie - N-1 | 133.8 | 254.0 | 2 | 3.5 | $148,298 | 14.1 |

# Appendix B Connection Point Sensitivity Studies

For the connection point assessments considered in detail, AEMO has conducted sensitivity studies by varying the VCR, discount rate and nominated augmentation costs.

The base values applied in the main studies are:

- VCR of $45,767/MWh
- Discount rate of 10%
- Base augmentation cost as nominated by ElectraNet

The sensitivities applied to these values are:

- VCR of $38,240/MWh and $53,295/MWh
- Discount rate of 7% and 13%
- ±30% of base augmentation cost nominated by ElectraNet

The following sub-sections tabulate these sensitivity studies to support the base assessments and any recommendations made by AEMO.

## B.1 Baroota

*Table 9 – Baroota sensitivity study: VCR of $38,240*

| Baroota - N line, N-1 Tx | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $22 million | +30% |
| NPV of Benefits ($) | 7% | $25,189,409 | $21,182,975 | $17,176,542 |
| Breakeven Demand (MW) | 7% | 3 MW | 4 MW | 6 MW |
| NPV of Benefits ($) | 10% | $12,572,552 | $9,271,852 | $5,971,153 |
| Breakeven Demand (MW) | 10% | 4 MW | 6 MW | 8 MW |
| NPV of Benefits ($) | 13% | $6,491,715 | $3,751,154 | $1,010,593 |
| Breakeven Demand (MW) | 13% | 5 MW | 8 MW | 10 MW |

*Table 10 - Baroota sensitivity study: VCR of $45,767*

| Baroota - N line, N-1 Tx | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $22 million | +30% |
| NPV of Benefits ($) | 7% | $31,988,133 | $27,981,699 | $23,975,265 |
| Breakeven Demand (MW) | 7% | 3 MW | 4 MW | 5 MW |
| NPV of Benefits ($) | 10% | $16,563,506 | $13,262,806 | $9,962,106 |
| Breakeven Demand (MW) | 10% | 4 MW | 5 MW | 7 MW |
| NPV of Benefits ($) | 13% | $9,028,383 | $6,287,821 | $3,547,260 |
| Breakeven Demand (MW) | 13% | 5 MW | 7 MW | 9 MW |

*Table 11 - Baroota sensitivity study: VCR of $53,295*

| Baroota - N line, N-1 Tx | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $22 million | +30% |
| NPV of Benefits ($) | 7% | $38,786,856 | $34,780,422 | $30,773,989 |
| Breakeven Demand (MW) | 7% | 2 MW | 3 MW | 4 MW |
| NPV of Benefits ($) | 10% | $20,554,459 | $17,253,759 | $13,953,060 |
| Breakeven Demand (MW) | 10% | 3 MW | 4 MW | 6 MW |
| NPV of Benefits ($) | 13% | $11,565,050 | $8,824,488 | $11,565,050 |
| Breakeven Demand (MW) | 13% | 4 MW | 6 MW | 4 MW |

## B.2 Dalrymple

*Table 12 - Dalrymple sensitivity study: VCR of $38,240*

| Dalrymple - N line, N-1 Tx | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $15 million | +30% |
| NPV of Benefits ($) | 7% | $43,897,782 | $40,969,315 | $38,040,848 |
| Breakeven Demand (MW) | 7% | 2 MW | 3 MW | 4 MW |
| NPV of Benefits ($) | 10% | $24,301,557 | $21,819,867 | $19,338,177 |
| Breakeven Demand (MW) | 10% | 3 MW | 4 MW | 5 MW |
| NPV of Benefits ($) | 13% | $14,420,523 | $12,303,180 | $10,185,838 |
| Breakeven Demand (MW) | 13% | 4 MW | 5 MW | 7 MW |

*Table 13 Dalrymple sensitivity study: VCR of $45,767*

| Dalrymple - N line, N-1 Tx | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $15 million | +30% |
| NPV of Benefits ($) | 7% | $53,884,105 | $50,955,638 | $48,027,171 |
| Breakeven Demand (MW) | 7% | 2 MW | 3 MW | 3 MW |
| NPV of Benefits ($) | 10% | $30,225,172 | $27,743,481 | $25,261,791 |
| Breakeven Demand (MW) | 10% | 2 MW | 3 MW | 5 MW |
| NPV of Benefits ($) | 13% | $18,231,715 | $16,114,372 | $13,997,030 |
| Breakeven Demand (MW) | 13% | 3 MW | 4 MW | 6 MW |

*Table 14 - Dalrymple sensitivity study: VCR of $53,295*

| Dalrymple - N line, N-1 Tx | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $15 million | +30% |
| NPV of Benefits ($) | 7% | $63,870,428 | $60,941,961 | $58,013,494 |
| Breakeven Demand (MW) | 7% | 2 MW | 2 MW | 3 MW |
| NPV of Benefits ($) | 10% | $36,148,786 | $33,667,095 | $31,185,405 |
| Breakeven Demand (MW) | 10% | 2 MW | 3 MW | 4 MW |
| NPV of Benefits ($) | 13% | $22,042,906 | $19,925,564 | $22,042,906 |
| Breakeven Demand (MW) | 13% | 3 MW | 4 MW | 3 MW |

## B.3 Port Lincoln

### B.3.1 Port Lincoln – Twin sulphur conductors (option one)

*Table 15 – Port Lincoln option one sensitivity study: VCR of $38,240*

| Port Lincoln - N-1 firm | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $396 million | +30% |
| NPV of Benefits ($) | 7% | -$119,811,833 | -$191,856,316 | -$263,900,798 |
| Breakeven Demand (MW) | 7% | 488 MW | 698 MW | 907 MW |
| NPV of Benefits ($) | 10% | -$111,010,650 | -$170,389,417 | -$229,768,184 |
| Breakeven Demand (MW) | 10% | 684 MW | 978 MW | 1271 MW |
| NPV of Benefits ($) | 13% | -$97,851,619 | -$147,168,322 | -$196,485,024 |
| Breakeven Demand (MW) | 13% | 886 MW | 1266 MW | 1646 MW |

*Table 16 - Port Lincoln option one sensitivity study: VCR of $45,767*

| Port Lincoln - N-1 firm | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $396 million | +30% |
| NPV of Benefits ($) | 7% | -$110,305,608 | -$182,350,091 | -$254,394,573 |
| Breakeven Demand (MW) | 7% | 408 MW | 583 MW | 758 MW |
| NPV of Benefits ($) | 10% | -$105,589,466 | -$164,968,232 | -$224,346,999 |
| Breakeven Demand (MW) | 10% | 572 MW | 817 MW | 1062 MW |
| NPV of Benefits ($) | 13% | -$94,461,744 | -$143,778,446 | -$193,095,149 |
| Breakeven Demand (MW) | 13% | 740 MW | 1058 MW | 1375 MW |

*Table 17 - Port Lincoln option one sensitivity study: VCR of $53,295*

| Port Lincoln - N-1 firm | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $396 million | +30% |
| NPV of Benefits ($) | 7% | -$100,799,383 | -$172,843,865 | -$244,888,348 |
| Breakeven Demand (MW) | 7% | 350 MW | 501 MW | 651 MW |
| NPV of Benefits ($) | 10% | -$100,168,281 | -$159,547,048 | -$218,925,815 |
| Breakeven Demand (MW) | 10% | 491 MW | 702 MW | 912 MW |
| NPV of Benefits ($) | 13% | -$91,071,868 | -$140,388,571 | -$91,071,868 |
| Breakeven Demand (MW) | 13% | 636 MW | 908 MW | 636 MW |

### B.3.2 Port Lincoln – Single sulphur conductors (option two)

*Table 18 - Port Lincoln option two sensitivity study: VCR of $38,240*

| Port Lincoln - N-1 firm (option 2) | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | | -30% | $309 million | +30% |
| NPV of Benefits ($) | 7% | -$82,879,940 | -$139,096,468 | -$195,312,996 |
| Breakeven Demand (MW) | 7% | 381 MW | 544 MW | 708 MW |
| NPV of Benefits ($) | 10% | -$80,571,534 | -$126,904,966 | -$173,238,398 |
| Breakeven Demand (MW) | 10% | 534 MW | 763 MW | 992 MW |
| NPV of Benefits ($) | 13% | -$72,570,582 | -$111,052,555 | -$149,534,527 |
| Breakeven Demand (MW) | 13% | 691 MW | 988 MW | 1284 MW |

*Table 19 - Port Lincoln option two sensitivity study: VCR of $45,767*

| Port Lincoln - N-1 firm (option 2) | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $309 million | +30% |
| NPV of Benefits ($) | 7% | -$73,373,714 | -$129,590,242 | -$185,806,770 |
| Breakeven Demand (MW) | 7% | 318 MW | 455 MW | 591 MW |
| NPV of Benefits ($) | 10% | -$75,150,350 | -$121,483,782 | -$167,817,214 |
| Breakeven Demand (MW) | 10% | 446 MW | 637 MW | 829 MW |
| NPV of Benefits ($) | 13% | -$69,180,707 | -$107,662,679 | -$146,144,652 |
| Breakeven Demand (MW) | 13% | 578 MW | 825 MW | 1073 MW |

*Table 20 - Port Lincoln option two sensitivity study: VCR of $53,295*

| Port Lincoln - N-1 firm (option 2) | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $309 million | +30% |
| NPV of Benefits ($) | 7% | -$63,867,489 | -$120,084,017 | -$176,300,545 |
| Breakeven Demand (MW) | 7% | 273 MW | 391 MW | 508 MW |
| NPV of Benefits ($) | 10% | -$69,729,166 | -$116,062,598 | -$162,396,030 |
| Breakeven Demand (MW) | 10% | 383 MW | 547 MW | 712 MW |
| NPV of Benefits ($) | 13% | -$65,790,831 | -$104,272,804 | -$65,790,831 |
| Breakeven Demand (MW) | 13% | 496 MW | 709 MW | 496 MW |

## B.4 Kadina East

*Table 21 – Kadina East sensitivity study: VCR of $38,240*

| Kadina East - N-1 firm | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $61 million | +30% |
| NPV of Benefits ($) | 7% | -$23,075,249 | -$34,173,011 | -$45,270,772 |
| Breakeven Demand (MW) | 7% | 494 MW | 706 MW | 918 MW |
| NPV of Benefits ($) | 10% | -$19,760,215 | -$28,906,944 | -$38,053,673 |
| Breakeven Demand (MW) | 10% | 693 MW | 990 MW | 1286 MW |
| NPV of Benefits ($) | 13% | -$16,750,149 | -$24,346,913 | -$31,943,678 |
| Breakeven Demand (MW) | 13% | 897 MW | 1281 MW | 1666 MW |

*Table 22 - Kadina East sensitivity study: VCR of $45,767*

| Kadina East - N-1 firm | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $61 million | +30% |
| NPV of Benefits ($) | 7% | -$22,520,228 | -$33,617,990 | -$44,715,751 |
| Breakeven Demand (MW) | 7% | 413 MW | 590 MW | 767 MW |
| NPV of Benefits ($) | 10% | -$19,448,770 | -$28,595,499 | -$37,742,228 |
| Breakeven Demand (MW) | 10% | 579 MW | 827 MW | 1075 MW |
| NPV of Benefits ($) | 13% | -$16,558,096 | -$24,154,860 | -$31,751,625 |
| Breakeven Demand (MW) | 13% | 749 MW | 1070 MW | 1392 MW |

*Table 23 - Kadina East sensitivity study: VCR of $53,295*

| Kadina East - N-1 firm | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $61 million | +30% |
| NPV of Benefits ($) | 7% | -$21,965,207 | -$33,062,969 | -$44,160,730 |
| Breakeven Demand (MW) | 7% | 355 MW | 507 MW | 659 MW |
| NPV of Benefits ($) | 10% | -$19,137,324 | -$28,284,053 | -$37,430,783 |
| Breakeven Demand (MW) | 10% | 497 MW | 710 MW | 923 MW |
| NPV of Benefits ($) | 13% | -$16,366,043 | -$23,962,807 | -$16,366,043 |
| Breakeven Demand (MW) | 13% | 643 MW | 919 MW | 643 MW |

## B.5 Fleurieu Peninsula

*Table 24 – Fleurieu Peninsula sensitivity study: VCR of $38,240*

| Fleurieu Peninsula - N-1 | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $243 million | +30% |
| NPV of Benefits ($) | 7% | $4,720,530,371 | $4,675,899,844 | $4,631,269,316 |
| Breakeven Demand (MW) | 7% | 5 MW | 7 MW | 9 MW |
| NPV of Benefits ($) | 10% | $2,478,689,410 | $2,441,821,121 | $2,404,952,831 |
| Breakeven Demand (MW) | 10% | 7 MW | 10 MW | 12 MW |
| NPV of Benefits ($) | 13% | $1,443,298,024 | $1,412,656,812 | $1,382,015,600 |
| Breakeven Demand (MW) | 13% | 9 MW | 12 MW | 16 MW |

*Table 25 - Fleurieu Peninsula sensitivity study: VCR of $45,767*

| Fleurieu Peninsula - N-1 | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $243 million | +30% |
| NPV of Benefits ($) | 7% | $5,670,261,643 | $5,625,631,115 | $5,581,000,587 |
| Breakeven Demand (MW) | 7% | 4 MW | 6 MW | 7 MW |
| NPV of Benefits ($) | 10% | $2,983,551,154 | $2,946,682,865 | $2,909,814,575 |
| Breakeven Demand (MW) | 10% | 6 MW | 8 MW | 10 MW |
| NPV of Benefits ($) | 13% | $1,741,483,791 | $1,710,842,579 | $1,680,201,367 |
| Breakeven Demand (MW) | 13% | 7 MW | 10 MW | 13 MW |

*Table 26 - Fleurieu Peninsula sensitivity study: VCR of $53,295*

| Fleurieu Peninsula - N-1 | | | | |
|---|---|---|---|---|
| | | Project Cost | | |
| | Discount Rate | -30% | $243 million | +30% |
| NPV of Benefits ($) | 7% | $6,619,992,915 | $6,575,362,387 | $6,530,731,859 |
| Breakeven Demand (MW) | 7% | 3 MW | 5 MW | 6 MW |
| NPV of Benefits ($) | 10% | $3,488,412,898 | $3,451,544,609 | $3,414,676,319 |
| Breakeven Demand (MW) | 10% | 5 MW | 7 MW | 9 MW |
| NPV of Benefits ($) | 13% | $2,039,669,558 | $2,009,028,346 | $2,039,669,558 |
| Breakeven Demand (MW) | 13% | 6 MW | 9 MW | 6 MW |

# Appendix C Transmission Plant Failure Rates

To support the robustness of the data provided by ElectraNet, AEMO compared ElectraNet's transmission plant outage rates with benchmark and observed transmission outage rates. Key comparison information has been included below, for information only, but has not been considered in any of the assessments included in this report.

*Table 27 – AEMO transmission line outage data*

| Voltage (kV) | 500 kV | 330 kV | 275 kV | 220kV | Pooled |
|---|---|---|---|---|---|
| Cct km | 1,516 | 739 | 156 | 4,177 | 6,588 |
| Years | 19 | 19 | 13 | 19 | 19 |
| Number of circuits | 17 | 6 | 2 | 105 | 130 |
| Observed unplanned outage frequencies and aggregate durations | | | | | |
| Frequency | 302 | 68 | 37 | 909 | 1,316 |
| Duration (hr) | 2,887 | 418 | 273 | 8,864 | 12,442 |
| Ave Duration (hr) | 9.6 | 5.9 | 7.4 | 14.1 | 9.5 |
| Max Duration (hr) | 283 | 166 | 28 | 1,824 | 1,824 |
| Frequency >50 hr | 11 | 1 | 0 | 28 | 40 |
| Benchmark unplanned outage frequencies and aggregate durations | | | | | |
| Frequency | 432 | 210 | 30 | 1,191 | 1,863 |
| Duration (hr) | 4,320 | 2,100 | 300 | 11,910 | 18,630 |

As AEMO is not responsible for planning connection point transformers, transformer forced outage data is primarily recorded for high capacity, high voltage transmission transformers. Based on transmission transformer forced outage data recorded over the same eighteen year period, each transmission transformer is expected to fail, on average, once in a 50 year period.

In additional to the transmission plant outage data recorded, AEMO investigated publically available transmission plant outage data and has included, for information, transmission cable forced outage data taken from a Transpower New Zealand Limited report[15], as outlined below:

*Table 28 – Transpower New Zealand Limited transmission plant outage rates*

| Transmission element | | Forced Outage Rate (outages/100 km line length/annum) | Average Forced Outage Duration (hr) |
|---|---|---|---|
| 220 kV overhead lines | | 0.34 | 1.8 |
| 400 kV overhead lines | Optimistic | 0.11 | 1.8 |
| | Pessimistic | 0.34 | 1.8 |
| 400 kV underground cable | Optimistic | 0.28 | 240.0 |
| | Pessimistic | 1.00 | 432.0 |

[15] Transpower New Zealand Limited, 2005, Comparison of the Reliabilty of a 400 kV Underground Cable with an Overhead Line for a 200 km Circuit; www.ea.govt.nz

# Appendix D Value of Customer Reliability

As described in Section 4.2.3, the higher sensitivity value of VCR assumed for this review was based on the 2007 Victorian VCR values, determined through a customer survey approach that estimated direct end-user customer costs incurred from power interruptions at the sector and state levels.

The 2007 Victorian values have been indexed on a sector-specific basis using an income/economic growth approach to estimate a 2010 VCR for South Australia. The income/economic growth approach considers the following:

- Agricultural sector: gross value-added of agricultural production at producer prices.
- Commercial/industrial sector: changes in gross state product (GSP).
- Residential sector: total gross household income.

Based on the KPMG report prepared for AEMO's 2010 Electricity Statement of Opportunities (ESOO)[16], the breakdown of load types across South Australia is as follows:

- Residential 37%.
- Agricultural 2%.
- Commercial 27%.
- Industrial 34%.

Using the South Australian load breakdown, an average headline VCR was developed. Table 29 below lists the 2010 headline and sector-specific VCRs estimated for South Australia.

*Table 29 – South Australian Value of Customer Reliability for 2010*

| Sector | VCR ($/MWh)* |
|---|---|
| Residential | $16,354 |
| Commercial | $108,927 |
| Agricultural | $109,311 |
| Industrial | $43,290 |
| **HEADLINE** | **$53,295** |

** Monetary units in 2009 dollars*

The headline VCR of $53,295/MWh was applied as an upper sensitivity when determining the appropriate reliability level at connection points. A headline VCR of $38,240/MWh was also considered as a lower sensitivity, giving sensitivity testing of ±16.45%.

[16] http://www.aemo.com.au/planning/esoo2010.html

# Appendix E Transmission Line Lengths

| 275 kV Transmission Line | Line one Length (km) | Line two Length (km) |
|---|---|---|
| BRINKWORTH - DAVENPORT (EAST CCT) | 148.59 | - |
| BUNGAMA - DAVENPORT (NEW - PART OF F1918) | 90.20 | - |
| CANOWIE - ROBERSTOWN | 78.75 | - |
| CHERRY GARDENS - HAPPY VALLEY | 8.41 | - |
| CHERRY GARDENS - TAILEM BEND (WAS PART F1938 & F1921) | 123.27 | - |
| CHERRY GARDENS - MORPHETT VALE EAST | 9.92 | - |
| DAVENPORT - BELALIE | 159.22 | - |
| DAVENPORT - BUNGAMA | 90.20 | - |
| DAVENPORT - CANOWIE | 133.85 | - |
| DAVENPORT - CULTANA No1 | 60.68 | - |
| DAVENPORT - CULTANA No2 | 61.28 | - |
| DAVENPORT - CULTANA No1 // DAVENPORT - CULTANA No2 | 60.68 | 61.28 |
| DAVENPORT - NORTHERN POWER STATION | 2.89 | - |
| HAPPY VALLEY - MORPHETT VALE EAST | 9.36 | - |
| KILBURN - NORTHFIELD | 9.58 | - |
| LEFEVRE - TIPS | 3.70 | - |
| MAGILL - EAST TCE (UNDERGROUND CABLE) | 7.88 | - |
| MAGILL - HAPPY VALLEY | 27.25 | - |
| MAGILL - TIPS A | 45.53 | - |
| MOKOTA - ROBERTSTOWN | 53.28 | - |
| NPS - DAVENPORT No1 | 2.89 | - |
| NPS - DAVENPORT No2 | 2.92 | - |
| NPS - DAVENPORT No1 // NPS - DAVENPORT No2 | 2.89 | 2.92 |
| PARA - BRINKWORTH (EAST CCT) | 134.18 | - |
| PARA - BUNGAMA | 189.50 | - |
| PARA - MAGILL | 22.75 | - |
| PARA - MAGILL No1 | 22.75 | - |
| PARA - PARAFIELD GARDENS WEST | 12.74 | - |
| PARA - ROBERTSTOWN (WAS PART F1904 & F1939) | 145.81 | - |
| PARA - TUNGKILLO | 39.57 | - |
| PARAFIELD GARDENS WEST - PARA | 12.74 | - |
| PELICAN POINT - LEFEVRE | 1.64 | - |
| PELICAN POINT - PARAFIELD GARDENS WEST | 13.12 | - |
| PLAYFORD - DAVENPORT No1 | 3.14 | - |
| ROBERTSTOWN - TUNGKILLO | 106.47 | - |
| SOUTH EAST - HEYWOOD No1 | 12.36 | - |
| SOUTH EAST - HEYWOOD No2 | 12.36 | - |
| TAILEM BEND - SOUTH EAST No1 | 308.14 | - |
| TAILEM BEND - SOUTH EAST No2 | 308.14 | - |
| TAILEM BEND - SOUTH EAST No1 // TAILEM BEND - SOUTH EAST No2 | 308.14 | 308.14 |
| TIPS - CHERRY GARDENS | 67.00 | - |
| TIPS - KILBURN | 10.17 | - |
| TIPS - MAGILL | 45.53 | - |
| TIPS - NORTHFIELD | 12.34 | - |
| TIPS - PARA (No4) | 20.83 | - |
| TUNGKILLO - CHERRY GARDENS (WAS PART F1939) | 57.80 | - |
| TUNGKILLO - TAILEM BEND (WAS PART F1904) | 62.13 | - |

| 132 kV Transmission Line | Line one Length (km) | Line two Length (km) |
|---|---|---|
| ANGAS CREEK - MANNUM | 32.60 | - |
| ARDROSSAN WEST - DALRYMPLE . | 65.98 | - |
| BLANCHE - MOUNT GAMBIER | 16.92 | - |
| BLANCHE - SNUGGERY | 43.29 | - |
| BRINKWORTH - MINTARO | 45.70 | - |
| BUNGAMA - BAROOTA | 26.08 | - |
| BUNGAMA - BAROOTA | 26.08 | - |
| BUNGAMA - BRINKWORTH | 57.04 | - |
| BUNGAMA - PORT PIRIE | 6.31 | - |
| BUNGAMA - REDHILL - BRINKWORTH | 57.04 | - |
| CHERRY GARDENS-MOUNT BARKER | 19.90 | - |
| CULTANA - STONY POINT | 24.46 | - |
| CULTANA - WHYALLA | 9.88 | - |
| DAVENPORT - NORTHERN POWER STATION | 0.77 | - |
| DAVENPORT - WHYALLA No 1 | 68.60 | - |
| DAVENPORT - WHYALLA No 2 | 70.78 | - |
| DAVENPORT - LEIGH CREEK | 246.98 | - |
| DAVENPORT - PIMBA | 175.92 | - |
| HUMMOCKS - ARDROSSAN WEST | 43.29 | - |
| HUMMOCKS - KADINA EAST | 39.56 | - |
| HUMMOCKS - KADINA EAST | 39.56 | - |
| HUMMOCKS - SNOWTOWN - BUNGAMA | 102.10 | - |
| HUMMOCKS - SNOWTOWN - BUNGAMA | 102.10 | - |
| HUMMOCKS-WATERLOO | 83.17 | - |
| KEITH - KINCRAIG | 104.24 | - |
| KEITH - SNUGGERY | 180.55 | - |
| KINCRAIG - PENOLA WEST | 61.35 | - |
| MANNUM - MOBILONG | 16.46 | - |
| MANNUM-ADELAIDE PUMP STATION No1 | 4.13 | - |
| MINTARO - BRINKWORTH | 45.70 | - |
| MOBILONG - No 1 PUMP STATION | 4.04 | - |
| MOBILONG - TAILEM BEND | 32.28 | - |
| MONASH - BERRI NO1 | 3.55 | - |
| MOBILONG - TAILEM BEND // MONASH - BERRI NO1 | 32.28 | 3.55 |
| MONASH - BERRI No2 | 6.94 | - |
| MONASH - NORTH WEST BEND 1 | 88.08 | - |
| MT BARKER - MOBILONG (MTBK-No 3 PUMP | 19.17 | - |
| MT BARKER - MOBILONG (No2 PS TO MOBILONG) | 6.08 | - |
| MT BARKER - MOBILONG(No3 PS TO KANMANTOO) | 4.38 | - |
| MT BARKER - MOBILONG(No3 PS TO No2 PS) | 18.56 | - |
| NORTH WEST BEND - MONASH No1 | 88.08 | - |
| NORTH WEST BEND - MONASH No2 | 86.47 | - |
| NORTH WEST BEND - MONASH No1 // NORTH WEST BEND - MONASH No2 | 88.08 | 86.47 |
| NORTHFIELD - ANGAS CREEK (ISOLATED) | 11.50 | - |
| NORTHFIELD - PARA (LINE TURNED BACK AT TOWER 7) | 1.93 | - |
| PARA - ANGAS CREEK | 34.42 | - |
| PARA - ROSEWORTHY | 23.94 | - |
| PARA - ROSEWORTHY | 23.94 | - |
| PENOLA WEST - SOUTH EAST | 36.96 | - |
| PENOLA WEST - SOUTH EAST | 36.96 | - |

| | | |
|---|---|---|
| PIMBA - WOOMERA | 12.25 | - |
| PLAYFORD - WHYALLA TERMINAL 1 | 68.60 | - |
| PLAYFORD A & B SWITCHYARD TIE NO 1 | 0.19 | - |
| PLAYFORD - WHYALLA TERMINAL 1 // PLAYFORD A & B SWITCHYARD TIE NO 1 | 68.60 | 0.19 |
| PLAYFORD A & B SWITCHYARD TIE NO 2 | 0.27 | - |
| REDHILL - CLEMENTS GAP WINDFARM | 14.23 | - |
| REDHILL - CLEMENTS GAP WINDFARM | 14.23 | - |
| ROBERTSTOWN - NORTH WEST BEND 1 | 60.25 | - |
| ROBERTSTOWN - NORTH WEST BEND 1 | 60.25 | - |
| ROBERTSTOWN - NORTH WEST BEND 2 | 5.93 | - |
| ROBERTSTOWN - NORTH WEST BEND 2 | 58.06 | - |
| ROBERTSTOWN - NORTH WEST BEND 1 // ROBERTSTOWN - NORTH WEST BEND 2 | 60.25 | 58.06 |
| ROBERTSTOWN - NWBEND 2 (ROBTN TO No 3 PUMP) | 5.93 | - |
| ROBERTSTOWN - NWBEND2 (No3 TO No2 PUMP) | 22.00 | - |
| ROBERTSTOWN - NWBEND2(No1 PS TO NW BEND) | 5.14 | - |
| ROBERTSTOWN - NWBEND2(No2 PS TO No1 PS) | 25.00 | - |
| ROSEWORTHY - DORRIEN (Combined 1867 & 1842) | 28.20 | - |
| SLEAFORD - PT LINCOLN | 29.73 | - |
| SNUGGERY - BLANCHE | 43.29 | - |
| SNUGGERY - MAYURRA | 10.54 | - |
| SOUTH EAST - MOUNT GAMBIER | 13.96 | - |
| SOUTH EAST - SNUGGERY 132KV | 42.16 | - |
| TAILEM BEND - KEITH 1 | 120.55 | - |
| TAILEM BEND - KEITH 1 | 120.55 | - |
| TAILEM BEND - KEITH 2 | 121.39 | - |
| TAILEM BEND - KEITH 1 // TAILEM BEND - KEITH 2 | 120.55 | 121.39 |
| TEMPLERS - DORRIEN | 18.79 | - |
| TEMPLERS - WATERLOO | 55.51 | - |
| WATERLOO - MINTARO | 16.59 | - |
| WATERLOO - ROBERTSTOWN 2 (No4 PUMP) | 17.41 | - |
| WATERLOO - ROBERTSTOWN 2(No4 PS-ROBERTSN) | 7.20 | - |
| WHYALLA - YADNARIE | 136.82 | - |
| WHYALLA TERMINAL - MIDDLEBACK - YADNARIE | 136.82 | - |
| YADNARIE - MT MILLAR | 32.75 | - |
| YADNARIE - MT MILLAR | 32.75 | - |
| YADNARIE - PORT LINCOLN | 126.11 | - |
| YADNARIE - PORT LINCOLN | 126.11 | - |
| YADNARIE - WUDINNA | 120.23 | - |

# Appendix F Detailed Connection Point Economic Assessments

*Table 30 – Baroota detailed connection point economic assessment*

| CONNECTION POINT - Baroota | | | Pre-augmentation | | Post-augmentation | | | |
|---|---|---|---|---|---|---|---|---|
| Year | MW | PF | Cost of unserved energy | Cumulative cost of unserved energy | Cost of unserved energy | Annual savings of unserved energy | Annual repayments | Annual Benefits |
| 09/10 | 8.7 | 0.97 | | | | | | |
| 10/11 | 8.9 | 0.97 | $0 | $0 | $0 | $0 | $0 | $0 |
| 11/12 | 9.0 | 0.97 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12/13 | 9.2 | 0.97 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13/14 | 9.4 | 0.97 | $0 | $0 | $0 | $0 | $0 | $0 |
| 14/15 | 9.5 | 0.96 | $0 | $0 | $0 | $0 | $0 | $0 |
| 15/16 | 9.7 | 0.96 | $0 | $0 | $0 | $0 | $0 | $0 |
| 16/17 | 9.8 | 0.96 | $0 | $0 | $0 | $0 | $0 | $0 |
| 17/18 | 10.0 | 0.96 | $4,552,436 | $4,552,436 | $163,632 | $4,388,804 | $2,230,602 | $2,158,202 |
| 18/19 | 10.2 | 0.96 | $4,629,828 | $9,182,264 | $166,414 | $4,463,414 | $2,230,602 | $2,232,811 |
| 19/20 | 10.4 | 0.96 | $4,708,535 | $13,890,798 | $169,243 | $4,539,292 | $2,230,602 | $2,308,689 |
| 20/21 | 10.5 | 0.96 | $4,788,580 | $18,679,378 | $172,120 | $4,616,459 | $2,230,602 | $2,385,857 |
| 21/22 | 10.7 | 0.95 | $4,869,986 | $23,549,363 | $175,046 | $4,694,939 | $2,230,602 | $2,464,337 |
| 22/23 | 10.9 | 0.95 | $4,952,775 | $28,502,139 | $178,022 | $4,774,753 | $2,230,602 | $2,544,151 |
| 23/24 | 11.1 | 0.95 | $5,036,972 | $33,539,111 | $181,048 | $4,855,924 | $2,230,602 | $2,625,322 |
| 24/25 | 11.3 | 0.95 | $5,122,601 | $38,661,712 | $184,126 | $4,938,475 | $2,230,602 | $2,707,873 |
| 25/26 | 11.5 | 0.95 | $5,209,685 | $43,871,397 | $187,256 | $5,022,429 | $2,230,602 | $2,791,827 |
| 26/27 | 11.6 | 0.95 | $5,298,250 | $49,169,647 | $190,440 | $5,107,810 | $2,230,602 | $2,877,208 |
| 27/28 | 11.8 | 0.95 | $5,388,320 | $54,557,967 | $193,677 | $5,194,643 | $2,230,602 | $2,964,041 |
| 28/29 | 12.0 | 0.94 | $5,479,922 | $60,037,889 | $196,970 | $5,282,952 | $2,230,602 | $3,052,350 |
| 29/30 | 12.3 | 0.94 | $5,573,080 | $65,610,969 | $200,318 | $5,372,762 | $2,230,602 | $3,142,160 |
| VCR | $45,767 | Terminal Value | $53,091,255 | | $1,908,306 | $51,182,949 | $21,249,553 | $29,933,396 |
| Discount Rate | 10% | Annual repayments assuming fixed annual payments | | | ($2,230,602) | | | |
| | | NPV | $25,169,840 | | $904,702 | $24,265,138 | $11,002,332 | $13,262,806 |
| | | Present Value of Benefits | | | $13,262,806 | | | |
| | | Breakeven demand (MW) | | | 5.1 | | | |

*Table 31 - Dalrymple detailed connection point economic assessment*

| CONNECTION POINT - Dalrymple | | | Pre-augmentation | | Post-augmentation | | | |
|---|---|---|---|---|---|---|---|---|
| Year | MW | PF | Cost of unserved energy | Cumulative cost of unserved energy | Cost of unserved energy | Annual savings of unserved energy | Annual repayments | Annual Benefits |
| 09/10 | 9.7 | 0.93 | | | | | | |
| 10/11 | 10.0 | 0.93 | $0 | $0 | $0 | $0 | $0 | $0 |
| 11/12 | 10.3 | 0.93 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12/13 | 10.6 | 0.93 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13/14 | 11.0 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 14/15 | 11.3 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 15/16 | 11.7 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 16/17 | 12.1 | 0.92 | $5,595,254 | $5,595,254 | $308,640 | $5,286,615 | $1,520,865 | $3,765,750 |
| 17/18 | 12.4 | 0.92 | $5,772,064 | $11,367,319 | $318,393 | $5,453,672 | $1,520,865 | $3,932,807 |
| 18/19 | 12.8 | 0.91 | $5,954,462 | $17,321,780 | $328,454 | $5,626,008 | $1,520,865 | $4,105,143 |
| 19/20 | 13.2 | 0.91 | $6,142,623 | $23,464,403 | $338,833 | $5,803,790 | $1,520,865 | $4,282,925 |
| 20/21 | 13.7 | 0.91 | $6,336,729 | $29,801,132 | $349,540 | $5,987,189 | $1,520,865 | $4,466,324 |
| 21/22 | 14.1 | 0.91 | $6,536,970 | $36,338,102 | $360,585 | $6,176,385 | $1,520,865 | $4,655,520 |
| 22/23 | 14.5 | 0.91 | $6,743,538 | $43,081,641 | $371,980 | $6,371,558 | $1,520,865 | $4,850,693 |
| 23/24 | 15.0 | 0.91 | $6,956,634 | $50,038,275 | $383,735 | $6,572,900 | $1,520,865 | $5,052,035 |
| 24/25 | 15.5 | 0.90 | $7,176,464 | $57,214,739 | $395,861 | $6,780,603 | $1,520,865 | $5,259,738 |
| 25/26 | 16.0 | 0.90 | $7,403,240 | $64,617,979 | $408,370 | $6,994,870 | $1,520,865 | $5,474,005 |
| 26/27 | 16.5 | 0.90 | $7,637,182 | $72,255,161 | $421,274 | $7,215,908 | $1,520,865 | $5,695,043 |
| 27/28 | 17.0 | 0.90 | $7,878,517 | $80,133,678 | $434,587 | $7,443,931 | $1,520,865 | $5,923,066 |
| 28/29 | 17.5 | 0.90 | $8,127,479 | $88,261,157 | $448,319 | $7,679,159 | $1,520,865 | $6,158,294 |
| 29/30 | 18.1 | 0.90 | $8,384,307 | $96,645,464 | $462,486 | $7,921,821 | $1,520,865 | $6,400,955 |
| VCR | $45,767 | Terminal Value | $79,474,955 | | $4,383,914 | $75,091,041 | $14,416,300 | $60,674,741 |
| Discount Rate | 10% | Annual repayments assuming fixed annual payments | | | ($1,520,865) | | | |
| | | NPV | $38,118,431 | | $2,102,649 | $36,015,782 | $8,272,301 | $27,743,481 |
| | | Present Value of Benefits | | | $27,743,481 | | | |
| | | Breakeven demand (MW) | | | 3.5 | | | |

*Table 32 – Port Lincoln option one detailed connection point economic assessment*

| CONNECTION POINT – Port Lincoln (option one) | | | Pre-augmentation | | Post-augmentation | | | |
|---|---|---|---|---|---|---|---|---|
| Year | MW | PF | Cost of unserved energy | Cumulative cost of unserved energy | Cost of unserved energy | Annual savings of unserved energy | Annual repayments | Annual Benefits |
| 09/10 | 90.0 | 0.93 | | | | | | |
| 10/11 | 92.3 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 11/12 | 94.7 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12/13 | 98.2 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13/14 | 100.7 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 14/15 | 103.4 | 0.91 | $0 | $0 | $0 | $0 | $0 | $0 |
| 15/16 | 106.1 | 0.91 | $0 | $0 | $0 | $0 | $0 | $0 |
| 16/17 | 109.0 | 0.91 | $0 | $0 | $0 | $0 | $0 | $0 |
| 17/18 | 112.0 | 0.91 | $6,678,493 | $6,678,493 | $1,222,573 | $5,455,920 | $39,810,572 | -$34,354,652 |
| 18/19 | 115.0 | 0.90 | $6,861,554 | $13,540,047 | $1,256,085 | $5,605,470 | $39,810,572 | -$34,205,102 |
| 19/20 | 118.2 | 0.90 | $7,051,417 | $20,591,464 | $1,290,841 | $5,760,576 | $39,810,572 | -$34,049,996 |
| 20/21 | 121.5 | 0.90 | $7,248,346 | $27,839,810 | $1,326,891 | $5,921,455 | $39,810,572 | -$33,889,117 |
| 21/22 | 124.9 | 0.90 | $7,452,619 | $35,292,429 | $1,364,286 | $6,088,333 | $39,810,572 | -$33,722,239 |
| 22/23 | 128.5 | 0.90 | $7,664,521 | $42,956,951 | $1,403,077 | $6,261,445 | $39,810,572 | -$33,549,127 |
| 23/24 | 132.2 | 0.91 | $7,884,353 | $50,841,304 | $1,443,319 | $6,441,033 | $39,810,572 | -$33,369,539 |
| 24/25 | 136.0 | 0.91 | $8,112,423 | $58,953,727 | $1,485,070 | $6,627,353 | $39,810,572 | -$33,183,219 |
| 25/26 | 140.0 | 0.90 | $8,349,056 | $67,302,783 | $1,528,388 | $6,820,667 | $39,810,572 | -$32,989,905 |
| 26/27 | 144.1 | 0.90 | $8,594,587 | $75,897,370 | $1,573,336 | $7,021,251 | $39,810,572 | -$32,789,321 |
| 27/28 | 148.3 | 0.90 | $8,849,366 | $84,746,735 | $1,619,976 | $7,229,390 | $39,810,572 | -$32,581,182 |
| 28/29 | 152.8 | 0.90 | $9,113,756 | $93,860,491 | $1,668,375 | $7,445,380 | $39,810,572 | -$32,365,192 |
| 29/30 | 157.4 | 0.90 | $9,388,135 | $103,248,626 | $1,718,604 | $7,669,531 | $39,810,572 | -$32,141,041 |
| VCR | $45,767 | Terminal Value | $92,167,051 | | $16,872,214 | $75,294,837 | $390,836,202 | -$315,541,365 |
| Discount Rate | 10% | Annual repayments assuming fixed annual payments | | | ($39,810,572) | | | |
| | | NPV | $40,346,954 | | $7,385,963 | $32,960,990 | $197,929,223 | -$164,968,232 |
| | | Present Value of Benefits | | | ($164,968,232) | | | |
| | | Breakeven demand (MW) | | | 816.9 | | | |

*Table 33 – Port Lincoln option two detailed connection point economic assessment*

| CONNECTION POINT – Port Lincoln (option two) | | | Pre-augmentation | | Post-augmentation | | | |
|---|---|---|---|---|---|---|---|---|
| Year | MW | PF | Cost of unserved energy | Cumulative cost of unserved energy | Cost of unserved energy | Annual savings of unserved energy | Annual repayments | Annual Benefits |
| 09/10 | 90.0 | 0.93 | | | | | | |
| 10/11 | 92.3 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 11/12 | 94.7 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12/13 | 98.2 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13/14 | 100.7 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 14/15 | 103.4 | 0.91 | $0 | $0 | $0 | $0 | $0 | $0 |
| 15/16 | 106.1 | 0.91 | $0 | $0 | $0 | $0 | $0 | $0 |
| 16/17 | 109.0 | 0.91 | $0 | $0 | $0 | $0 | $0 | $0 |
| 17/18 | 112.0 | 0.91 | $6,678,493 | $6,678,493 | $1,222,573 | $5,455,920 | $31,064,310 | -$25,608,390 |
| 18/19 | 115.0 | 0.90 | $6,861,554 | $13,540,047 | $1,256,085 | $5,605,470 | $31,064,310 | -$25,458,840 |
| 19/20 | 118.2 | 0.90 | $7,051,417 | $20,591,464 | $1,290,841 | $5,760,576 | $31,064,310 | -$25,303,734 |
| 20/21 | 121.5 | 0.90 | $7,248,346 | $27,839,810 | $1,326,891 | $5,921,455 | $31,064,310 | -$25,142,855 |
| 21/22 | 124.9 | 0.90 | $7,452,619 | $35,292,429 | $1,364,286 | $6,088,333 | $31,064,310 | -$24,975,977 |
| 22/23 | 128.5 | 0.90 | $7,664,521 | $42,956,951 | $1,403,077 | $6,261,445 | $31,064,310 | -$24,802,865 |
| 23/24 | 132.2 | 0.91 | $7,884,353 | $50,841,304 | $1,443,319 | $6,441,033 | $31,064,310 | -$24,623,277 |
| 24/25 | 136.0 | 0.91 | $8,112,423 | $58,953,727 | $1,485,070 | $6,627,353 | $31,064,310 | -$24,436,957 |
| 25/26 | 140.0 | 0.90 | $8,349,056 | $67,302,783 | $1,528,388 | $6,820,667 | $31,064,310 | -$24,243,643 |
| 26/27 | 144.1 | 0.90 | $8,594,587 | $75,897,370 | $1,573,336 | $7,021,251 | $31,064,310 | -$24,043,059 |
| 27/28 | 148.3 | 0.90 | $8,849,366 | $84,746,735 | $1,619,976 | $7,229,390 | $31,064,310 | -$23,834,920 |
| 28/29 | 152.8 | 0.90 | $9,113,756 | $93,860,491 | $1,668,375 | $7,445,380 | $31,064,310 | -$23,618,930 |
| 29/30 | 157.4 | 0.90 | $9,388,135 | $103,248,626 | $1,718,604 | $7,669,531 | $31,064,310 | -$23,394,779 |
| VCR | $45,767 | Terminal Value | $92,167,051 | | $16,872,214 | $75,294,837 | $304,970,673 | -$229,675,836 |
| Discount Rate | 10% | Annual repayments assuming fixed annual payments | | | ($31,064,310) | | | |
| | | NPV | $40,346,954 | | $7,385,963 | $32,960,990 | $154,444,772 | -$121,483,782 |
| | | Present Value of Benefits | | | ($121,483,782) | | | |
| | | Breakeven demand (MW) | | | 637.4 | | | |

*Table 34 – Kadina East detailed connection point economic assessment*

| CONNECTION POINT – Kadina East | | | Pre-augmentation | | Post-augmentation | | | |
|---|---|---|---|---|---|---|---|---|
| Year | MW | PF | Cost of unserved energy | Cumulative cost of unserved energy | Cost of unserved energy | Annual savings of unserved energy | Annual repayments | Annual Benefits |
| 09/10 | 26.4 | 0.93 | | | | | | |
| 10/11 | 27.6 | 0.93 | $0 | $0 | $0 | $0 | $0 | $0 |
| 11/12 | 28.9 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 12/13 | 30.2 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 13/14 | 31.5 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 14/15 | 32.9 | 0.92 | $0 | $0 | $0 | $0 | $0 | $0 |
| 15/16 | 34.4 | 0.91 | $0 | $0 | $0 | $0 | $0 | $0 |
| 16/17 | 36.0 | 0.91 | $0 | $0 | $0 | $0 | $0 | $0 |
| 17/18 | 37.6 | 0.91 | $497,141 | $497,141 | $218,277 | $278,864 | $6,132,437 | -$5,853,572 |
| 18/19 | 39.3 | 0.91 | $519,512 | $1,016,654 | $228,099 | $291,413 | $6,132,437 | -$5,841,024 |
| 19/20 | 41.1 | 0.90 | $542,891 | $1,559,544 | $238,364 | $304,527 | $6,132,437 | -$5,827,910 |
| 20/21 | 42.9 | 0.90 | $567,321 | $2,126,865 | $249,090 | $318,230 | $6,132,437 | -$5,814,206 |
| 21/22 | 44.8 | 0.90 | $592,850 | $2,719,715 | $260,299 | $332,551 | $6,132,437 | -$5,799,886 |
| 22/23 | 46.9 | 0.90 | $619,528 | $3,339,243 | $272,013 | $347,515 | $6,132,437 | -$5,784,921 |
| 23/24 | 49.0 | 0.90 | $647,407 | $3,986,650 | $284,253 | $363,154 | $6,132,437 | -$5,769,283 |
| 24/25 | 51.2 | 0.91 | $676,540 | $4,663,191 | $297,045 | $379,496 | $6,132,437 | -$5,752,941 |
| 25/26 | 53.5 | 0.90 | $706,985 | $5,370,175 | $310,412 | $396,573 | $6,132,437 | -$5,735,864 |
| 26/27 | 55.9 | 0.90 | $738,799 | $6,108,974 | $324,380 | $414,419 | $6,132,437 | -$5,718,018 |
| 27/28 | 58.4 | 0.90 | $772,045 | $6,881,019 | $338,977 | $433,068 | $6,132,437 | -$5,699,369 |
| 28/29 | 61.0 | 0.90 | $806,787 | $7,687,806 | $354,231 | $452,556 | $6,132,437 | -$5,679,881 |
| 29/30 | 63.8 | 0.90 | $843,092 | $8,530,899 | $370,172 | $472,921 | $6,132,437 | -$5,659,516 |
| VCR | $45,767 | Terminal Value | $8,276,973 | | $3,634,124 | $4,642,849 | $60,204,566 | -$55,561,718 |
| Discount Rate | 10% | Annual repayments assuming fixed annual payments | | | ($6,132,437) | | | |
| | | NPV | $3,375,786 | | $1,482,188 | $1,893,599 | $30,489,097 | -$28,595,499 |
| | | Present Value of Benefits | | | ($28,595,499) | | | |
| | | Breakeven demand (MW) | | | 826.8 | | | |

*Table 35 – Fleurieu Peninsula detailed connection point economic assessment*

| CONNECTION POINT - Fleurieu Peninsula | | | Pre-augmentation | | Post-augmentation | | | |
|---|---|---|---|---|---|---|---|---|
| Year | MW | | Cost of unserved energy | Cumulative cost of unserved energy | Cost of unserved energy | Annual savings of unserved energy | Annual repayments | Annual Benefits |
| 16/17 | 111.0 | | $0 | $0 | $0 | $0 | $0 | $0 |
| 17/18 | 118.0 | | $365,610,484 | $365,610,484 | $3,117,983 | $362,492,502 | $24,429,215 | $338,063,287 |
| 18/19 | 124.0 | | $384,200,848 | $749,811,332 | $3,276,524 | $380,924,324 | $24,429,215 | $356,495,109 |
| 19/20 | 131.0 | | $405,889,606 | $1,155,700,938 | $3,461,489 | $402,428,116 | $24,429,215 | $377,998,901 |
| 20/21 | 139.0 | | $430,676,757 | $1,586,377,695 | $3,672,878 | $427,003,879 | $24,429,215 | $402,574,664 |
| 21/22 | 147.0 | | $455,463,908 | $2,041,841,603 | $3,884,267 | $451,579,642 | $24,429,215 | $427,150,427 |
| 22/23 | 156.0 | | $483,349,454 | $2,525,191,057 | $4,122,079 | $479,227,375 | $24,429,215 | $454,798,160 |
| 23/24 | 165.0 | | $511,234,999 | $3,036,426,056 | $4,359,891 | $506,875,108 | $24,429,215 | $482,445,893 |
| 24/25 | 174.0 | | $539,120,545 | $3,575,546,601 | $4,597,703 | $534,522,841 | $24,429,215 | $510,093,627 |
| 25/26 | 185.0 | | $573,202,878 | $4,148,749,479 | $4,888,363 | $568,314,515 | $24,429,215 | $543,885,300 |
| 26/27 | 196.0 | | $607,285,211 | $4,756,034,690 | $5,179,022 | $602,106,189 | $24,429,215 | $577,676,974 |
| 27/28 | 207.0 | | $641,367,545 | $5,397,402,235 | $5,469,682 | $635,897,863 | $24,429,215 | $611,468,648 |
| 28/29 | 220.0 | | $681,646,666 | $6,079,048,901 | $5,813,188 | $675,833,477 | $24,429,215 | $651,404,263 |
| 29/30 | 233.0 | | $721,925,787 | $6,800,974,688 | $6,156,695 | $715,769,092 | $24,429,215 | $691,339,877 |
| 30/31 | 247.0 | | $765,303,302 | $7,566,277,990 | $6,526,625 | $758,776,677 | $24,429,215 | $734,347,462 |
| 31/32 | 262.0 | | $811,779,211 | $8,378,057,201 | $6,922,979 | $804,856,232 | $24,429,215 | $780,427,018 |
| 32/33 | 278.0 | | $861,353,514 | $9,239,410,715 | $7,345,756 | $854,007,758 | $24,429,215 | $829,578,543 |
| 33/34 | 295.0 | | $914,026,211 | $10,153,436,925 | $7,794,957 | $906,231,254 | $24,429,215 | $881,802,039 |
| 34/35 | 313.0 | | $969,797,302 | $11,123,234,227 | $8,270,582 | $961,526,720 | $24,429,215 | $937,097,505 |
| 35/36 | 332.0 | | $1,028,666,786 | $12,151,901,014 | $8,772,630 | $1,019,894,157 | $24,429,215 | $995,464,942 |
| VCR | $45,767 | Terminal Value | $9,953,902,550 | $117,587,969,280 | $84,888,422 | $9,869,014,128 | $236,389,495 | $9,632,624,633 |
| Discount Rate | 10% | Annual repayments assuming fixed annual payments | | | ($24,429,215) | | | |
| | | | NPV | $3,095,980,162 | $26,402,998 | $3,069,577,163 | $122,894,298 | $2,946,682,865 |
| | | Present Value of Benefits | | | $2,946,682,865 | | | |
| | | Breakeven demand (MW) | | | 8.0 | | | |

# Appendix G Adelaide Central and North Eastern Suburbs

Source: http://www.electranet.com.au/