SOUTH AUSTRALIAN TRANSMISSION ANNUAL PLANNING REPORT

May 2015

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Glossary of Terms

Term	Description
10% POE	10% Probability of Exceedance: used to indicate a value that is expected to be exceeded once in every 10 years, on average
AC	Alternating current
ADE	Adelaide zone
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMD	Agreed Maximum Demand
ARENA	Australian Renewable Energy Agency
CBD	Central Business District
CPI	Consumer Price Index
DNSP	Distribution Network Service Provider
ESCOSA	Essential Services Commission of South Australia
ESD	Energy Storage Device
ESCRI-SA	Energy Storage for Commercial Renewable Integration – South Australia
ESOO	Electricity Statement of Opportunities
ETC	Electricity Transmission Code (South Australia)
GSOO	Gas Statement of Opportunities
GST	Goods and Service Tax
HVDC	High Voltage Direct Current
kA	kiloAmperes
km	kilometres
kV	kiloVolts
MVA	MegaVolt-Ampere
Mvar	MegaVolt-Ampere Reactive
MW	MegaWatt
N	System normal network, with all network elements in-service
N-1	One network element out-of-service, with all other network elements in-service
NEFR	National Electricity Forecast Report, published by AEMO
NEM	National Electricity Market
NPV	Net Present Value
NTNDP	National Transmission Network Development Plan
NSA	Northern South Australia zone
OFGS	Over-frequency Generator Shedding
PADR	Project Assessment Draft Report
POE	Probability of Exceedance
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report

PSCR	Project Specification Consultation Report
P-V	Power versus Voltage analysis
PV	Photovoltaic
Q-V	Reactive Power versus Voltage analysis
RIT-T	Regulatory Investment Test for Transmission
Rules	National Electricity Rules
SESA	South East South Australia region
SVC	Static VAR Compensator
TNSP	Transmission Network Service Provider
UFLS	Under-frequency Load Shedding

Executive Summary

Purpose of the South Australian Transmission Annual Planning Report

The South Australian Transmission Annual Planning Report (the Report) provides information to market participants and other interested parties on the current capacity and emerging limitations of South Australia's electricity transmission network.

The Report covers a ten-year planning period and includes a description of the current network; demand projections; emerging network limitations or constraints; and information on completed, committed, pending and proposed transmission network developments.

This information informs stakeholders and helps potential loads and generators to identify and assess opportunities in the National Electricity Market (NEM) and also assists in the preparation of the National Transmission Network Development Plan (NTNDP) by the Australian Energy Market Operator (AEMO). The NTNDP provides information on the strategic and long-term development of the national transmission system under a range of market development scenarios.

What's New in 2015?

The following major changes have been made:

- The Report has been published earlier than the required end of June publication date to better align with the annual planning cycle and the reliance of the reported planning outcomes on 2014 forecasts of electricity demand[1];
- In early 2015 ElectraNet published the inaugural South Australian Connection Point Forecasts Report, which includes the demand forecasts relied upon in this Transmission Annual Planning Report – it also contains load profile information for each transmission network connection point to help with assessing the viability of non-network solution options[2] for addressing network limitations as an alternative to network investment;
- Scenario planning – This Report considers three planning scenarios that represent a wide range of potential futures: a Base scenario; a SA Mining Growth scenario; and a SA Renewable Generation Expansion scenario. The Report identifies emerging limitations and potential solutions to these limitations for all scenarios studied;
- Information is presented on network capability to accommodate new generator connections (as well as customer load connections); and
- Additional content is provided on the approach to considering non-network solutions for addressing network limitations for the benefit of non-network solution proponents.

Demand Forecast and Summer Review

Transmission network planning is based on forecasts of electricity demand rather than energy consumption to ensure sufficient capacity to meet maximum demand for electricity. A decline in large industrial demand forecasts, the rapid uptake of rooftop solar photovoltaic (PV) systems and customer energy efficiency measures have all had an impact on reducing energy consumption and, to a lesser extent, maximum demand.

[1] Electricity demand is the amount of electrical power (rate at which energy flows) being consumed at any given time.
[2] A "non-network" solution is a service that avoids or defers a need for network augmentation. It is usually provided by demand-side response or embedded generation support (or both), through a Network Support Agreement.

AEMO publishes an annual South Australian state-wide demand forecast by 30 June each year, which forms part of AEMO's National Electricity Forecast Report (NEFR). The AEMO NEFR demand forecast is based on econometric modelling and does not consider load requirements at a localised connection point level. However, AEMO has also published South Australian connection point forecasts for the first time in December 2014.

AEMO's 2014 NEFR forecasts South Australian state-wide 10% Probability of Exceedance (10% POE[3]) maximum demand to decrease at an average annual rate of 1.1% over the short term (3-year outlook) under a medium economic growth scenario[4]. However, development of new loads, in particular potential new mining loads under higher economic growth scenarios, would see maximum demand via the transmission network increase, requiring transmission network augmentation in parts of the network.

SA Power Networks and customers connected directly to the transmission network provide demand forecasts for their connection points to the transmission network on an annual basis. ElectraNet uses these forecasts as input to develop regional and state level demand forecasts which are a key input to the planning and development of the transmission network.

ElectraNet has worked with SA Power Networks and AEMO to improve demand forecasts at an individual connection point level and to reconcile them with AEMO's State level forecasts. ElectraNet's 2015 South Australian Connection Points Forecasts report shows close agreement between the ElectraNet and AEMO forecasts.

Overall the 2014-15 summer was quite mild in metropolitan Adelaide. High temperature conditions were experienced in early January 2015 accompanied by significant bushfire events in the Adelaide Hills. However, despite this, no heat events occurred of sufficient intensity and duration to cause extreme electricity demand outcomes. Despite the mild summer seven connection points met or exceeded either ElectraNet's 10% POE connection point demand forecasts or AEMO's 10% POE connection point demand forecasts.

Planning Outcomes

The information and analysis presented in this Report is based on three planning scenarios, representing differing assumptions about the future development of demand and generation in South Australia. The three scenarios and resulting outcomes are summarised in the table below.

Scenario	Key Characteristics	10-year Planning Outcomes
Base scenario	Demand forecast: 2014 10% POE Generation plant: Existing fleet	No significant projected network limitations
SA Mining Growth scenario	Demand forecast: 70 - 770 MW of new mining load, 10% increase to base forecast in 2023-24 Generation plant: Minimum expansion to conventional fleet	Significant network augmentation required in specific parts of the network depending on actual mining developments driving this investment
SA Renewable Generation Expansion scenario	Demand forecast: 2014 10% POE Generation plant: 150 – 1860 MW of new wind generation, existing conventional fleet	Moderate network augmentation required to avoid significant network congestion at maximum demand times At low demand times wind generation output may be limited by the ability to export power from South Australia

3 10% POE indicates a value that is expected to be exceeded once in every 10 years, on average.
4 AEMO, National Electricity Forecasting Report for the National Electricity Market, June 2014.

For all scenarios, other key assumptions including generator plant retirements are unchanged from the 2014 NTNDP (i.e. no retirements within the next 10 years). This Report identifies emerging limitations and proposes potential solutions to these limitations for all scenarios studied. The full characteristics of the three planning scenarios and resulting outcomes for each are covered in sections 7.3 to 7.8 of this Report.

Non-network Development Opportunities

The Report includes estimates of the amount of load reduction required to achieve a twelve month deferral of planned augmentations for the relevant scenarios. This information is intended to provide non-network solution proponents, including demand side proponents, with a guide to the scale of required solutions that could defer the need for network investment. ElectraNet welcomes proposals for alternative solutions to address identified network limitations from potential proponents of non-network solutions.

Network Capability and Inter-regional Planning

ElectraNet works closely with AEMO and other TNSPs through a joint planning process to plan works required on major flow paths of the transmission network, including interconnectors. The following specific developments or investigations have been progressed over the past 12 months to address current or future network constraints:

- Implementation of the Heywood interconnector upgrade project, which will increase nominal interconnector transfer capability between South Australia and Victoria by about 40% from 460 MW to 650 MW. This upgrade is due to be completed in mid-2016, with the full transfer capability increase being released later in 2016 following completion of inter-network testing;
- Investigation of the potential of a further incremental upgrade to increase the nominal capacity of the Heywood interconnector. While early indications as reported in 2014 suggested that forecast higher gas prices could make a further interconnector upgrade economic, more detailed investigation has shown this not to be the case at this time;
- A joint planning study with AEMO to develop an in-depth understanding of transmission limitations in the Riverland/Western Victoria and to identify potential solutions. The immediate outcome of the study is for ElectraNet to increase the summer thermal ratings of the Riverland 132 kV lines as soon as practicable to continue to meet the applicable reliability standards. ElectraNet and AEMO will continue to jointly monitor the need for and ability of Murraylink to provide capacity support for both the South Australian Riverland 132 kV network and the Regional Victorian 220 kV network in future years; and
- In October 2014 ElectraNet and AEMO published a joint report on renewable generation integration in South Australia[5]. The report concluded that the South Australian power system can operate securely and reliably with a high proportion of renewable generation as long as the Heywood Interconnector is fully intact and at least one synchronous generator is connected. The report also recommended that further work be performed, which AEMO and ElectraNet are progressing.

This Report provides information on the top binding constraints on the South Australian transmission network during the 2014 calendar year. This information includes commentary on the constraints identified and potential solutions to alleviate them. Potential network augmentations to alleviate constraints would be required to demonstrate net market benefits before they can be implemented. Most of the constraints with substantial hours binding will be significantly alleviated when the increased transfer capability resulting from the Heywood interconnector upgrade is released in the second half of 2016.

5 Renewable Energy Integration in South Australia, Joint AEMO and ElectraNet Study, October 2014.

Major Network Developments

This report provides information on augmentation, connection and material replacement projects that have been completed in 2014-15, are in progress, or are potential future developments.

Reducing energy consumption and growth in maximum electricity demand means that no major new augmentation projects are forecast to be needed over the 10-year planning period under the base case planning scenario.

There is only one Regulatory Investment Test for Transmission (RIT-T)[6] process active, which is for an upgrade of the Baroota connection point.

Baroota Substation Upgrade

The South Australian Electricity Transmission Code (ETC) requires equivalent N-1 transformer capacity at the Baroota connection point from 1 December 2017. A Project Specification Consultation Report (PSCR) was published in May 2014. One submission was received from generators and a late submission accepted from a non-network proponent.

ElectraNet has undertaken a comprehensive review and option analysis to determine the overall solution that maximises net economic benefits to consumers. This work has included revisiting the assumptions that underpinned the 2010 AEMO analysis, which resulted in the Essential Services Commission of South Australia (ESCOSA) changing the Baroota ETC reliability standard from category 1 to category 2, and thereby requiring equivalent N-1 transformer capacity.

While, the 2010 analysis indicated that the benefits to customers from improved reliability would outweigh the costs, ElectraNet's revised economic analysis has shown a significantly lower customer benefit from the upgrade than the original analysis and that the least cost network solution to meet the category 2 reliability standard does not produce a positive net market benefit.

ElectraNet actively engaged with the non-network proponent to refine the technical and commercial characteristics of the solution it proposed. Despite the efforts of the proponent to reduce costs, the economic analysis shows that the identified non-network solution does not produce a positive net market benefit either.

In summary, no technically feasible option has been identified that meets the category 2 reliability standard and results in a positive net benefit to customers. Given this outcome, ElectraNet is engaging with ESCOSA to seek to remove the requirement for equivalent N-1 transformer capacity at Baroota from 1 December 2017, as the updated assumptions do not appear to support the N-1 re-categorisation. It is considered that this is in the best interests of South Australian consumers.

However, the RIT-T option analysis has indicated that a non-continuous N-1 equivalent transformer solution at Baroota connection point may deliver positive net benefits to consumers. ElectraNet intends to explore this option further.

[6] The RIT-T is the public economic cost benefit test administered by the Australian Energy Regulator that must be undertaken for all augmentation projects with credible solutions estimated to cost more than $5 Million.

Consumer Feedback

This Report provides information to market participants and other interested parties on the outlook for the South Australian transmission network in order to assist potential loads and generators to identify and assess opportunities in the market.

ElectraNet welcomes feedback on the Report, including suggestions for improving the value of the information provided to all interested parties.

1. Introduction

About this chapter

Chapter 1 provides information about ElectraNet's role and responsibilities as a Transmission Network Service Provider and the framework within which it operates when planning the transmission system.

ElectraNet is the principal Transmission Network Service Provider (TNSP) in the South Australian region of the National Electricity Market (NEM). ElectraNet plans, builds, owns, operates and maintains South Australia’s high voltage electricity transmission network.

ElectraNet, in conjunction with SA Power Networks, the company responsible for South Australia’s electricity distribution network, undertakes an annual review of the capability of its transmission network and regulated connection points to meet forecast electricity demand under a variety of operating scenarios. The outcome of that review and other analysis undertaken by ElectraNet is presented in this South Australian Transmission Annual Planning Report to provide information to market participants and other interested parties on the current capacity and emerging limitations of the South Australian electricity transmission network.

1.1 ElectraNet’s Role in the Supply of Electricity

South Australia’s electricity transmission network operates mainly at 275,000 Volts (275 kV) and 132,000 Volts (132 kV) and forms the backbone of the electricity supply system which transports power from local and interstate generation sources to metropolitan and regional areas of demand (load centres).

Our customers include power generators, the State's electricity distributor SA Power Networks and large industry. The electricity transmission services ElectraNet provides also impact on the cost and reliability of electricity to consumers that are connected to SA Power Networks’ distribution network.

Figure 1-1 highlights ElectraNet's role in the electricity supply system. It also shows the role of other parts of the system in delivering reliable electricity supply to consumers.

ElectraNet's electricity transmission network facilitates lower electricity prices by promoting competition between generators in South Australia and interstate. We actively support and facilitate a wide range of traditional and renewable generation investment in South Australia and the growth of interconnector capability to deliver lowest long-run cost outcomes for energy consumers.

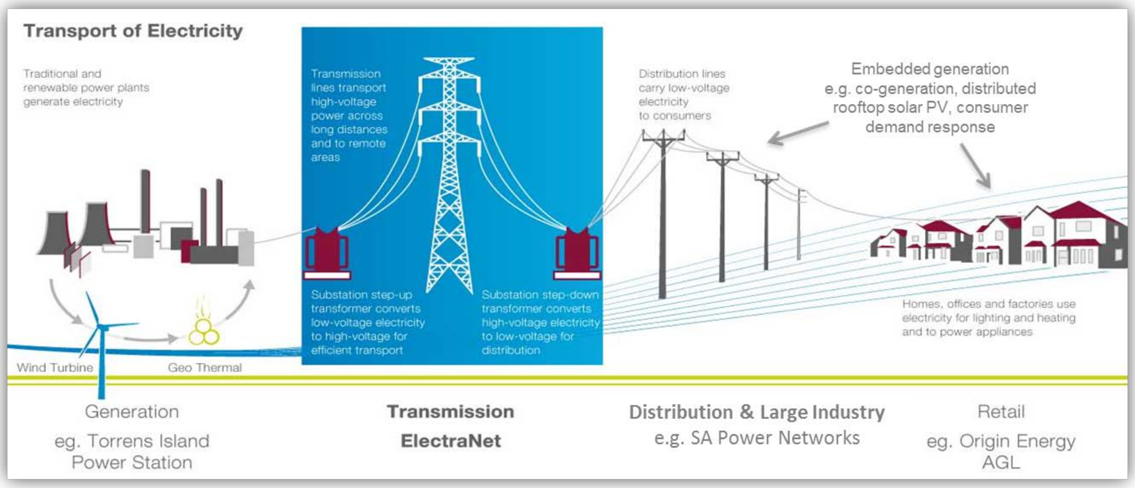

Figure 1-1: ElectraNet's Role in Electricity Supply

1.2 Purpose of this Transmission Annual Planning Report

The 2015 Transmission Annual Planning Report covers a 10-year period from 1 July 2015 to 30 June 2025. Projected limitations in the capability of the network have been identified for the next 10 year planning period and possible solutions to address those limitations are presented. Interested parties are encouraged to provide input to facilitate identification of the most appropriate solutions to ensure reliability and quality of supply can be maintained to customers at the lowest long-run cost. This report includes information for suppliers of demand side and non-network solutions to assist with the identification of solutions.

Consistent with clause 5.12.2(c)(6) of the National Electricity Rules (Rules), consideration has been given to the Australian Energy Market Operator’s (AEMO) 2014 National Transmission Network Development Plan (NTNDP) and information related to current or potential national transmission flow paths reported in the NTNDP.

This Transmission Annual Planning Report provides information to market participants and other interested parties on:

- Performance of the existing transmission network;
- Power transfer capability within the transmission system;
- The demand forecast for the next 10-year period;
- Planning proposals for future connection points to the network;
- Actual and potential network constraints;
- Proposed developments to the transmission network;
- Proposed replacement of transmission network assets; and
- Adequacy of the transmission network to enable the transfer of electrical power from generators to consumers.

The detailed requirements for the Transmission Annual Planning Report are set out in clause 5.12.2 of the Rules. These requirements and the relevant sections in this report that address them are provided in the compliance checklist which appears at Appendix I.

While every endeavour is made to make the information provided in this Transmission Annual Planning Report as accurate as possible, the planning of the transmission system is subject to uncertainty, including changes to demand forecast and generator behaviour, as well as potential changes to government policies.

Therefore, the Transmission Annual Planning Report does not define a single specific future development plan for the South Australian transmission system, but rather is intended to form part of a consultation process aimed at ensuring that the transmission network is efficiently and economically developed to meet forecast electricity demand over the planning period.

1.3 Continual Improvement

ElectraNet is committed to continuous improvement of the quality and value of the Transmission Annual Planning Report to industry stakeholders, including consumers. An indication of proposed further improvements to future Transmission Annual Planning Reports is provided in Appendix H. Stakeholders are invited to make other suggestions for future improvement by sending an email to:

consultation@electranet.com.au.

1.4 Responsibilities

ElectraNet is the principal TNSP and the Jurisdictional Planning Body for South Australia under clause 11.28.2 of the Rules.

Chapter 5 of the Rules deals with a TNSP's obligations with regard to network connection, network planning and establishing or modifying a connection point, including technical obligations that apply to all Registered Participants. In addition to the Rules, ElectraNet is also required to comply with the South Australian Electricity Transmission Code (ETC) as discussed in section 1.5.2.

ElectraNet's planning and development responsibilities with regard to the South Australian transmission network include:

- Ensuring that the network is planned, designed, constructed, operated and maintained with the safety of the public and workers as the paramount consideration;
- Ensuring that the network is operated with sufficient capability to provide the minimum level of transmission network services required by customers;
- Ensuring that the network complies with technical and reliability standards contained in the Rules and jurisdictional instruments such as the ETC;
- Ensuring that the network is planned, developed and operated such that there will be no requirements to shed load to achieve the Rules quality and reliability standards under normal and foreseeable operating conditions;

- Conducting joint planning with Distribution Network Service Providers (DNSPs) and other TNSPs whose networks are connected to the transmission network. That is, SA Power Networks, APA (Murraylink operator and part-owner) and AEMO;
- Providing information to registered participants and interested parties on projected network limitations and the required timeframes for action; and
- Developing recommendations to address projected network limitations through joint planning with DNSPs and consultation with registered participants and interested parties. Solutions may include network upgrades or non-network options, such as local generation and demand side management initiatives.

ElectraNet is also an active participant in inter-regional planning, providing advice on network developments which may have a material inter-network impact and participating in inter-regional system tests associated with new or augmented interconnections.

1.4.1 Rule Requirements for the Transmission Annual Planning Report

ElectraNet has conducted an annual planning review by analysing the expected future operation of the South Australian transmission network over a 10-year period, taking into account relevant forecast loads and future generation, market network service, demand side and transmission developments.

In accordance with clause 5.12.1(b) of the Rules, ElectraNet's annual planning review:

- Incorporates forecast demand, as submitted by SA Power Networks and direct connect customers or modified by ElectraNet in accordance with clause 5.11.1 of the Rules;
- Includes a review of the adequacy of existing connection points and relevant parts of the transmission system and planning proposals for future connection points;
- Takes into account AEMO's most recent NTNDP; and
- Considers the potential for augmentations, or non-network alternatives to augmentations, that are likely to provide a net economic benefit to all those who produce, consume and transport electricity in the market.

The results of ElectraNet's annual planning review are published in this 2015 Transmission Annual Planning Report as required by clause 5.12.2(a) of the Rules. Clause 5.12.2(c) states the information that must be presented within the Transmission Annual Planning Report. Clause 5.12.2(c) is reproduced within the Compliance Checklist that appears at Appendix I, which demonstrates ElectraNet's assessment of compliance with the requirements of the Rules.

1.5 Transmission Planning Framework

This section summarises the various regulatory arrangements upon which ElectraNet's planning processes are based and the environment which shapes the outcomes of the annual planning review.

1.5.1 Network Planning Approach

ElectraNet's approach to planning of the South Australian transmission network is driven by regulatory arrangements under the Rules and ETC. These arrangements are summarised in sections 1.4.1 and 1.5.2 respectively.

The Rules and ETC regulatory arrangements shape key inputs to the network planning process, including demand forecasts and network planning criteria and assumptions. Key outputs from the network planning process include the 2015 Transmission Annual Planning Report and reports published in accordance with the requirements of the Regulatory Investment Test for Transmission (RIT-T) as discussed in 1.5.3. The planning approach for developing the 2015 Transmission Annual Planning Report is shown in Figure 1-2.

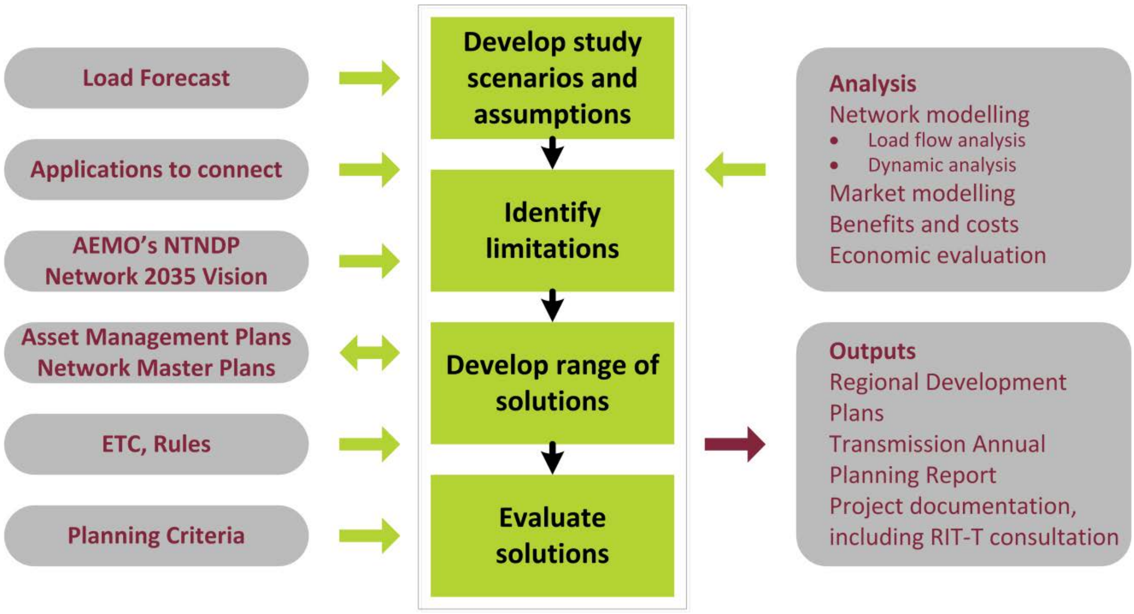

Figure 1-2: Approach to Planning

1.5.2 Reliability Standards

The ETC sets minimum standards for transmission system redundancy and restoration times at each transmission load connection point and requirements relating to planning, developing and operating the South Australian transmission system. The Essential Services Commission of South Australia (ESCOSA) is the body responsible for the ETC and its principal functions and powers are summarised in Appendix G.

ESCOSA most recently amended the reliability standards contained in the ETC effective from 1 July 2013[7]. Table 1-1 summarises these standards.

In late 2014, ESCOSA engaged AEMO to review the allocation of connection points to ETC reliability categories. This is in preparation for a revision of the ETC that is intended to apply for ElectraNet's 2018 - 2023 regulatory control period.

7 Available at http://www.escosa.sa.gov.au/library/130701-ElectricityTransmissionCode-TC07_2.pdf.

Table 1-1: Summary of ETC redundancy requirement

Load Category	1	2	3	4	5
Generally Applies to…	Small loads, country radials, direct connect customers	Significant country radials	Medium sized loads with non-firm backup	Medium sized loads and large loads	Adelaide Central Business District (CBD)
Transmission line capacity					
'N' capacity	100% of Agreed MD				
'N-1' capacity	Nil		100% of Agreed MD		
'N-1' continuous capability	Nil			100% of Agreed MD for loss of single transmission line or network support arrangement	
Restoration time to 'N' standard after outage (as soon as practicable - best endeavours)	2 days		1 hour	12 hours (or 4 hours if grouped with category 5 connection point)	4 hours for 65% of 'N' standard
Restoration time to 'N-1' standard after outage	N/A		As soon as practicable - best endeavours		
Transformer capacity					
'N' capacity	100% of Agreed MD				
'N-1' capacity	Nil	100% of Agreed MD			
'N-1' continuous capability	None stated	100% of Agreed MD for loss of single transformer or network support arrangement	Nil	100% of Agreed MD for loss of single transformer or network support arrangement	
Restoration time to 'N' standard after outage (as soon as practicable - best endeavours)	8 days		1 hour	12 hours (or 4 hours if grouped with category 5 connection point)	4 hours for 65% of 'N' standard
Restoration time to 'N-1' standard after outage	N/A	As soon as practicable - best endeavours			
Spare transformer requirement	Sufficient spares of each type to meet standards in the event of a failure				
Allowed period to comply with required contingency standard following a change in forecast Agreed MD that causes the specific reliability standard to be breached	N/A	12 months			

Note: the provision of 'N' and 'N-1' equivalent capacity, as described by the ETC, includes the capacity that is provided by in-place network support arrangements (through distribution system capability, generator capability, load interruptability, or any combination of these services).

1.5.3 Regulatory Investment Test for Transmission (RIT-T)

Investments in transmission network infrastructure are subject to the requirements of the RIT-T. The RIT-T is an economic cost benefit analysis which is used to assess and rank alternative electricity investment options.

ElectraNet applies the RIT-T, as promulgated by the Australian Energy Regulator (AER), in accordance with clauses 5.15 and 5.16 of the Rules and with the AER's Regulatory investment test for transmission (RIT-T) and application guidelines 2010. The RIT-T is designed to deliver solutions to identified network limitations that maximise the present value of net economic benefits to all those who produce, consume and transport electricity in the NEM. Solutions to network limitations may include both network and non-network options.

Clause 5.16.3(a) of the Rules requires ElectraNet to apply the RIT-T to all transmission investments with the exception of:

- Urgent or unforeseen network issues that would otherwise put at risk the reliability of the transmission network;
- Investments where the estimated capital cost of the most expensive feasible option is less than $5 Million;
- Replacement and maintenance projects where the estimated capital cost of the augmentation component (if there is one) is less than $5 Million;
- Network reconfigurations that have an estimated capital cost of less than $5 Million, or otherwise, are likely to have no material impact on network users;
- Connection assets; or
- Negotiated transmission service investments.

The RIT-T took effect on 1 August 2010 and assesses the costs and market benefits of transmission investments with the solution delivering the highest benefit on a net present value basis being deemed to pass the test[8].

Registered participants and interested parties have an opportunity and are encouraged to be involved during the RIT-T consultation process. In particular, proponents are invited to submit details of potential non-network options such as generation, market network services and demand side management initiatives that are technically and economically feasible and that reliably satisfy the identified network limitation.

All RIT-T reports published by ElectraNet and non-confidential submissions received during the consultation process are available from the RIT-T Projects page on ElectraNet's website. Projects which have recently completed the RIT-T but are not yet fully committed are presented in section 7.2.3 of this Transmission Annual Planning Report.

Figure 1-3 provides a summary of the process followed by ElectraNet when undertaking the RIT-T.

[8] Noting that where the investment is undertaken for a reliability corrective action, a preferred option may have a negative net economic benefit (that is, a net economic cost).

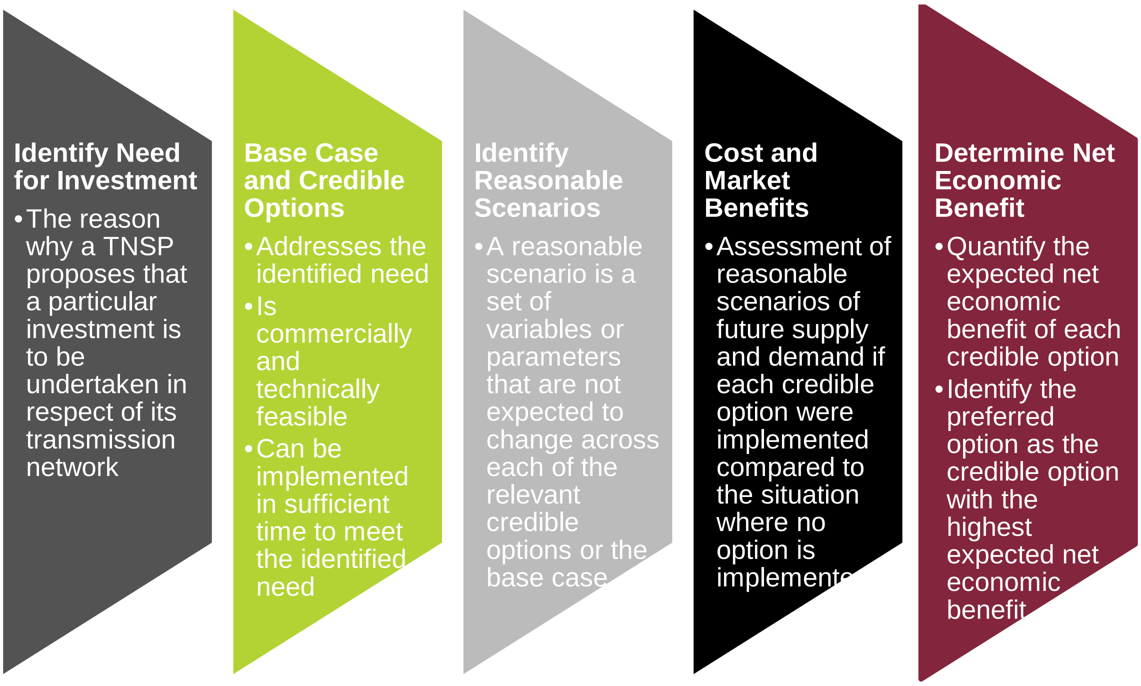

Figure 1-3: Summary of the RIT-T process

1.6 Structure of this Transmission Annual Planning Report

Chapter 2 provides relevant background information relating to the context, configuration, and capability of ElectraNet's transmission network.

Chapter 3 takes account of AEMO's 2014 NTNDP and assesses recent and forecast transmission network constraints. It identifies projects that may have the potential in the future to yield net market benefits.

Chapter 4 describes the demand assumptions that have been used to develop the plans that are described in this Transmission Annual Planning Report, and reviews the demand forecasts for SA connection points in the light of the 2014-15 summer. Note that in early 2015, ElectraNet published the 2015 South Australian Connection Point Forecasts Report, which contains details of the 10-year demand forecast at each connection point that formed the basis of the analysis that underpins this Transmission Annual Planning Report. It is available on ElectraNet's website[9].

Chapter 5 describes a range of significant planning investigations that have been undertaken by ElectraNet since the publication of the 2014 Transmission Annual Planning Report, and provides an indication of intended future planning investigations.

Chapter 6 describes potential generator and load connection opportunities.

Chapter 7 provides information about recently-completed, committed, and pending projects. It also describes a range of scenarios that have been considered for the planning of future projects, outlines the future limitations that would need to be addressed for each of the scenarios, and options to address these limitations.

[9] Available at http://www.electranet.com.au/network/transmission-planning/south-australian-connection-point-forecasts-report/

2. Overview of the South Australian Transmission System

About this chapter

Chapter 2 provides a high-level view of the South Australian transmission system and the changing nature of the transmission planning environment, as well as describing the capability of the interconnectors that link the South Australian and Victorian transmission networks.

This chapter contains information that was presented in parts of chapters 1 and 7 in the 2014 Transmission Annual Planning Report, including descriptions of the characteristics and capabilities of ElectraNet's electricity transmission network.

Drawings showing each regional electricity transmission network are provided in Appendix A.

2.1 Background

The South Australian transmission system has been developed to connect the major load centres in the state with the various sources of generation. The majority of base and intermediate conventional generation plant are located in the North and Central (Adelaide) regions of South Australia. Peaking power stations are spread out throughout the State. There are two interconnectors with Victoria: Heywood interconnector in the South East, and Murraylink interconnector in the Riverland.

The South Australian transmission network was developed with a high capacity 275 kV Main Grid. The Main Grid links the generators and interconnectors to major load centres (including the Adelaide metropolitan area), and to lower capacity 132 kV regional transmission systems providing supply to regional load centres.

A geographic representation of the existing South Australian Transmission network is shown in Figure 2-1. The 275 kV transmission network traverses a North to South direction from Cultana in the North to the South East at the southern extremity of South Australia. Four 275 kV transmission lines connect the North and Central (Adelaide) regions, and two 275 kV transmission lines connect the Central and South East regions. There are underlying 132 kV meshed transmission lines which sometimes limit the ability of this 275 kV network to transmit power.

A simplified view of the main transmission system in South Australia is shown in Figure 2-2, indicating the 275 kV corridors and the two interconnectors with Victoria. The Heywood interconnector comprises a 275 kV AC interconnector which connects South East in South Australia to Heywood in Victoria, and has an existing maximum capacity of ±460 MW. The Murraylink High Voltage Direct Current (HVDC) interconnector connects Monash in South Australia to Red Cliffs in Victoria, and has a maximum capacity of 220 MW at the receiving end. While the theoretical combined maximum thermal capability of the two interconnectors is 680 MW, this is not a firm capability and there are limits imposed in real time operation which are determined for different operating and environmental conditions. An upgrade of the Heywood Interconnector is scheduled to be completed by July 2016. This will increase the notional capacity of Heywood Interconnector to ±650 MW.

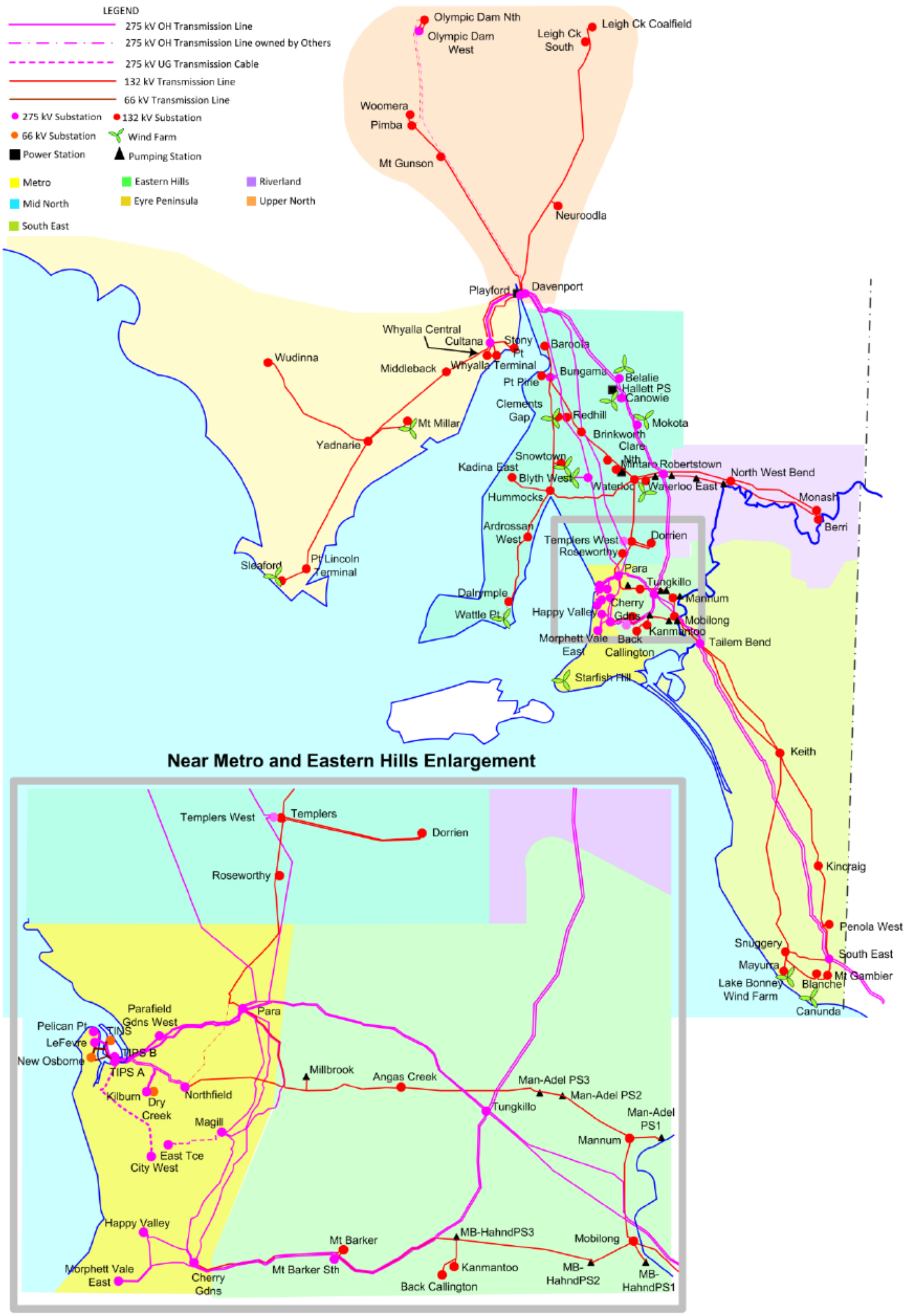

Figure 2-1: Representation of the existing network

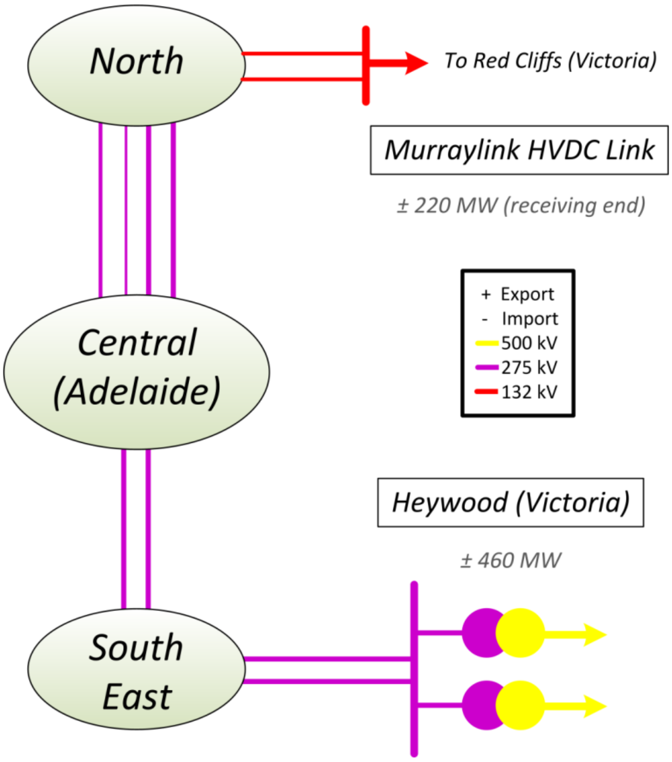

Figure 2-2: Simplified view of 275 kV backbone network

Historically, South Australian generation was supplemented by import from Victoria via the Heywood and Murraylink interconnectors, especially during maximum demand periods.

2.2 Recent Developments

Since 2000, previous government policy responses to climate change have resulted in an increase in the number of renewable energy generators, particularly wind generators, connecting to the transmission network at various locations throughout South Australia. Over 1400 MW of wind generation has been installed in the South Australian system to date, supplying about 31% of the state's energy demand in 2013-14[10]. Furthermore, due to the high quality wind resource available in South Australia, there is still potential interest in developing additional wind generation in the State. This has resulted in increasing use of the interconnectors to export power out of South Australia. However, in recent times, due to increasing gas prices and the availability of lower cost generation from elsewhere in the NEM, import of power has become prevalent even during lower demand periods with good level of wind generation.

The South Australian load profile is characterised by its very ‘peaky’ nature with relatively low energy content. This means that even though the maximum summer peak demand exceeds 3000 MW, demand ranges between 1000 MW and 2000 MW for most of the year. This peaky demand characteristic is an important consideration in assessing the requirement to augment the network to meet high demand. In recent times, with the addition of significant domestic roof-top solar photovoltaic (PV) generation throughout the system, there is a consequent reduction in the net demand, especially at summer peak times and on other sunny days. Given that the very high

10 South Australian Wind Study Report, AEMO, p. 21. Published October 2014. Available at http://www.aemo.com.au/Electricity/Planning/South-Australian-Advisory-Functions/South-Australian-Wind-Study-Report

demands only occur for about 1-2% of the year, there is the potential to defer network augmentations by implementing non-network solutions such as demand side management and local generation support, if shown to be technically and economically viable. ElectraNet actively considers such options along with transmission and distribution network augmentation options to deliver the least cost solution to customers, while fulfilling the obligations under the Rules and the ETC.

There are times when significant wind generation coupled with low system demand can result in low levels of conventional generating units connected to the system. This has the potential to cause instability in the system and reduce interconnector transfer limits. This issue could be exacerbated with the addition of more wind farms; however, it can be resolved by dispatching a minimum set of conventional generation (at technical minimum level of output) and Static VAR Compensators (SVCs) to provide the required system inertia and power system damping. Such modes of operation also raise issues related to frequency control requirements in the system, due to the variability of wind generation. This is explored further in section 5.3.

As wind is an intermittent energy source which cannot be dispatched to match the load at any given instant in the same way conventional generation can be, consideration has to be given to the availability of wind generation, especially during maximum demand periods, to ensure the supply-demand balance can be reliably met. AEMO has assessed that there is an 85% probability that wind output will be at least 8.7% of installed capacity in South Australia during high demand periods during summer[11]. ElectraNet normally uses this level of generation as the reliable level of wind generation in its planning models. However, when assessing the capacity of radial parts of the transmission system, ElectraNet considers circumstances in which zero output is available from those wind farms that can affect the net loading on the radial network.

2.3 Existing Transmission Network

2.3.1 Main Grid

ElectraNet's Main Grid comprises a meshed 275 kV network that connects the Cultana substation, near Whyalla, to South East substation near Mount Gambier and includes two interconnections that connect South Australia to the Victorian region of the NEM. The Main Grid 275 kV transmission system notionally excludes the 275 kV network around the Adelaide metropolitan region, which, for network planning purposes, is analysed separately.

The South Australian Main Grid 275 kV transmission network has been developed progressively over the past 50 years and provides the connection to all significant sources of generation that supply South Australian loads, including those in the eastern states via the interconnections with Victoria. It also provides the main transmission corridor between these generators and the connection point substations, which in turn supply directly-connected customers and the distribution network owned by SA Power Networks.

Figure 2-3 is a geographical diagram of the Main Grid 275 kV transmission network.

[11] *Ibid*, p. 14.

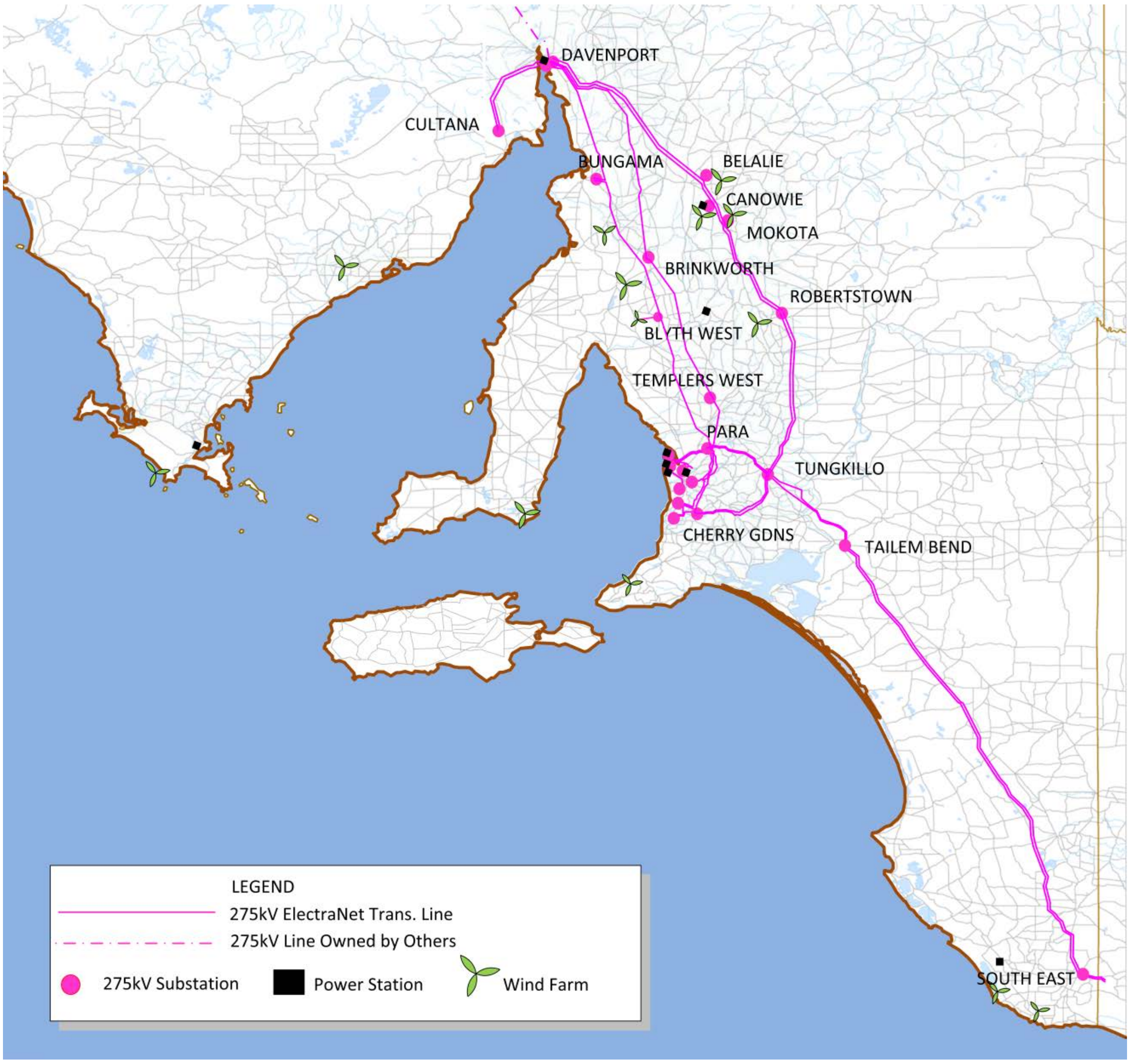

Figure 2-3: Geographical diagram of the Main Grid

2.3.2 Regional Networks

Representations of the regional networks are provided in Appendix A. To see how the regions and Main Grid relate to one another, refer back to Figure 2-1.

2.3.2.1 Metropolitan

The city of Adelaide is located about 10 kilometres inland from St. Vincent's Gulf, and is bounded by the Mount Lofty Ranges approximately 10 kilometres to the east. The Metropolitan 275 kV transmission region includes connection points that service the Adelaide central business district (CBD) and metropolitan residential, commercial and industrial loads. Over 80% of the South Australian population is contained within and serviced by the Metropolitan transmission region.

The Adelaide CBD contains South Australia's major centre of commerce and government. As the Adelaide metropolitan region has expanded, the 66 kV network has been progressively developed to accommodate the demand for electricity. The development of the interconnected 66 kV network has required sources of 275/66 kV injection to be established at strategic locations to meet the demand, and to provide an acceptable level of supply reliability.

2.3.2.2 Eastern Hills

The Eastern Hills 132 kV transmission system comprises a network that supplies major load centres at Angas Creek, Mount Barker, Mannum, Murray Bridge (Mobilong), Kanmantoo, and Strathalbyn, as well as a number of SA Water pumping stations on the Mannum-Adelaide and Murray Bridge-Hahndorf pipelines. The Eastern Hills region is bounded by the Mount Lofty Ranges to the west and the Murray River to the east.

The Eastern Hills transmission system derives its supply from the Main Grid 275 kV network via 275/132 kV substations located at Para (near Elizabeth), Cherry Gardens and Tailem Bend. It supplies the electricity requirements to five SA Power Networks connection point substations as well as to seven SA Water pumping stations in the region.

The Eastern Hills 132 kV network has been developed progressively since 1954, and has subsequently been overlaid by the 275 kV Main Grid transmission network. The Eastern Hills 132 kV system runs in parallel with the main 275 kV system that forms part of the South Australia to Victoria (Heywood) interconnection. As a consequence, power flows in the Eastern Hills are not only determined by the loads that must be supplied within the region, but also by flows on the Heywood interconnector.

2.3.2.3 Mid North

The Mid North 132 kV sub-transmission system comprises a network that supplies major load centres at Ardrossan, Brinkworth, Clare, Kadina and Port Pirie, as well as the Barossa Valley and Yorke Peninsula regions. It derives its supply from the Main Grid 275 kV system via 275/132 kV substations located at Para (near Elizabeth), Templers West, Robertstown, Brinkworth and Bungama (near Port Pirie). There is also a connection to the 132 kV Eastern Hills sub-transmission system at Para, and to the 132 kV Riverland sub-transmission system at Robertstown.

The Mid North 132 kV transmission region has been developed progressively since 1952. The Mid North 132 kV system operates in parallel with the 275 kV Main Grid system that connects the major sources of generation at Port Augusta with the Adelaide metropolitan load centre. As a consequence, power flows in the Mid North are not only determined by the loads that must be supplied within the region, but also by flows on the Murraylink interconnector and by flows on the Main Grid between Davenport and the Metropolitan region.

2.3.2.4 Riverland

The Riverland region is bounded by Robertstown to the west and the South Australian-New South Wales/Victoria borders to the east, and includes major load centres along the Murray River as far south as Swan Reach. The Riverland 132 kV transmission system comprises a network that supplies major load centres at Barmera, Berri, Blanchetown, Loxton, Renmark, and Waikerie. It derives its electricity supply from the Main Grid 275 kV network via two 275/132 kV transformers located at Robertstown substation and also from the Murraylink interconnector. This system supplies power to numerous SA Water pumping stations, in addition to servicing SA Power Networks' Berri and North West Bend connection point substations.

The Riverland 132 kV system has been developed progressively since 1953 and comprises two 132 kV circuits that essentially connect Robertstown 275/132 kV substation to Berri 132/66 kV substation via a number of intermediate connection points. The Riverland 132 kV system also provides a connection for the Murraylink interconnector that connects South Australia to Victoria. As a consequence, power flows in the Riverland sub-transmission system are determined by both the loads supplied within the region and flows on this interconnector.

2.3.2.5 South East

The South East supply area is the region bounded by the South Australia/Victoria border on the east, the Riverland region on the north, the Eastern Hills region to the north-west and the Southern Ocean to the west. The South East region of South Australia contains a mixture of electrical loads including agricultural, light and heavy industrial, rural, urban and commercial. The South East 132 kV transmission system comprises a network that supplies major load centres at Beachport, Keith, Kincraig, Kingston, Millicent, Mount Gambier (the main urban centre and second largest city in South Australia), Naracoorte, Penola, Robe and Tailem Bend. It derives its supply from the Main Grid 275 kV network via 275/132 kV substations located at Tailem Bend and South East (approximately 15 km north of Mount Gambier).

The 275 kV network was extended to Tailem Bend in 1976 and a 275/132 kV substation was established at that location to feed into the South East 132 kV network. Gas turbine generating plant was installed at Snuggery in 1980 and a 132/33 kV substation constructed at Blanche (about 15 km south west of Mount Gambier) in 1981.

The South East network was further augmented as part of the South Australia-Victoria (Heywood) interconnector project in 1989 when the 275/132 kV South East substation was established just north of Mount Gambier and connected to the Kincraig-Mount Gambier 132 kV line. The South East substation was connected to the Victorian transmission system at Heywood 500/275 kV substation via a 90 km of double circuit 275 kV line, and to Tailem Bend by approximately 310 km of double circuit 275 kV line.

2.3.2.6 Eyre Peninsula

The Eyre Peninsula supply area is the area south of Port Augusta, bounded by the regional border to the Upper North region on the north, by Spencer Gulf on east and by Great Australian Bight on west. The Eyre Peninsula region of South Australia contains a mixture of electrical loads including agricultural, light and heavy industrial, rural, urban and commercial. The Eyre Peninsula 132 kV transmission network is characterised by long radial lines and is supplied from the Main Grid 275 kV transmission network via the 275/132 kV substation Cultana (approximately 15 km north west of Whyalla). The major industrial centre of Whyalla is supplied from Cultana by 132 kV lines, which are operated in parallel. The remainder of the Eyre Peninsula is supplied from Cultana by radial 132 kV lines, with most of the load being supplied by the single long Cultana to Yadnarie 132 kV line. At Yadnarie, multiple radial 132 kV supply lines supply the main connection points at Wudinna and Port Lincoln.

The 275 kV network in Eyre Peninsula was extended from Port Augusta to Cultana in 1993. From 2014, the 132 kV lines that formerly connected Whyalla to Davenport have been reconfigured so that Whyalla and Middleback are now connected directly to Cultana at 132 kV.

2.3.2.7 Upper North

The Upper North 132kV sub-transmission network comprises a network that supplies major mining loads at Olympic Dam, Prominent Hill and Leigh Creek. It also supplies a mix of agricultural, industrial, rural, urban and commercial loads in the area. It derives its supply from the Main Grid 275 kV transmission system via a 275/132 kV Davenport substation (near Port Augusta), which also supplies the region's major commercial centre.

The Upper North 132 kV sub-transmission network comprises two radial 132 kV lines that run from Davenport to Leigh Creek and Woomera respectively. These lines supply a number of intermediate sites along their routes and provide connection to several regional communities. In addition to the two 132 kV radial lines, there is a privately owned Olympic Dam - Pimba 132 kV line and also a privately owned Davenport-Olympic Dam 275 kV line. These lines supply power to the mining operations in the north of South Australia, and are indicated by dashed lined in Figure 2-1.

A 275 kV connection point was provided at Davenport in 1998 to facilitate expansion of mining operations at Olympic Dam. A privately owned 275 kV transmission line and 275/132 kV substation was constructed at Olympic Dam as part of this expansion.

2.4 Inter-regional Transfer Capability

The combined maximum transfer capability for import into South Australia from Victoria under system normal operating conditions is 680 MW across the Heywood and Murraylink interconnectors.

To avoid oscillatory instability, the combined maximum transfer capability for export from South Australia to Victoria under existing system normal operating conditions is limited to 580 MW. This combined limit is being reviewed prior to the Heywood Third 500/275 kV transformer entry into service in September 2015 as part of the Heywood Interconnector upgrade.

However, inter-regional transfer into and out of South Australia can, at times, be constrained to lower levels due to prior network outages, thermal limitations, and limitations due to power system stability (angular or voltage). The actual transfer limit experienced in the market will depend not only on the capacity of network elements, but also on the market dispatch of scheduled generation, and the operation of non-scheduled generation.

2.4.1 Heywood Interconnector

The existing Heywood interconnector comprises a double circuit 275 kV transmission line from South East substation in South Australia to Heywood substation in Victoria, where two 275/500 kV transformers make the connection to the Victorian 500 kV transmission system.

Thermal and network security related constraints on the existing Heywood interconnector that limit transfer capability are principally related to the 460 MW limitation of transformer capacity at Heywood. There are also voltage and transient stability constraints on the South Australian network following a sudden loss of the largest South Australian generating unit, and thermal limitations on the underlying 132 kV transmission system from South East to Para and Cherry Gardens substations.

These limitations may result in constrained power flows from time to time.

2.4.1.1 Import Capability

The import capability of the interconnector is defined by two types of equations (for system normal operating conditions):

1. Thermal Transfer Capability

   This equation is determined by AEMO and is based on plant and equipment rating parameters provided by ElectraNet as the asset owner.

   The South East region 275 kV and 132 kV networks operate in parallel. Generation installed in the South East 132 kV transmission system tends to displace import on the Heywood interconnector. In accordance with the Rules, Schedule S5.2.5.12, generation is allowed to connect to existing networks and displace interconnection flows into a region but by no more than on a one-for-one basis.

   South Australian Heywood interconnector import is currently limited by the Heywood 500/275 kV transformers to 460 MW under system normal operating conditions.

2. Long Term and Short Term Voltage Stability Transfer Capability

   The import capability of the Heywood interconnector due to long term and short term voltage stability constraints under system normal operating conditions has been revised to take into account all recently completed projects in South Australia and a revised approach to identifying voltage limitations.

   In 2014, ElectraNet reviewed the system normal and N-1 voltage stability limit equations to cover changing generator dispatch patterns and to increase the accuracy and effectiveness of the voltage stability limit equations. As a result of this review process, ElectraNet has developed one set of long term steady state voltage limit equations and one set of short term voltage stability limit equations to cover the majority of network operating conditions, using the largest output of a single generating unit as a term in the equations.

   The updated SA system normal equations are included in Appendix C of this Transmission Annual Planning Report.

2.4.1.2 Export Capability

The export capability of the interconnector is currently defined by two types of equations (for system normal operating conditions):

1. Thermal Limit Transfer Capability

   This equation is determined by AEMO and is based on plant/equipment ratings/ parameters provided by ElectraNet.

   The South Australia to Victoria export capability on the Heywood interconnector is currently capped at 460 MW under system normal conditions, limited by the N-1 short term capability of the Heywood 500/275 kV transformers in Victoria until the third Heywood 500/275 kV transformer is in service. This current thermal limit will be reviewed as part of the Heywood interconnector upgrade project.

   In practice, there are conditions when export will be constrained below 460 MW by thermal limits of the 132 kV transmission network in the South East region and the South East 275/132 kV transformers, generation levels and system demand in the South East region of South Australia.

Based on the current South Australian transmission network configuration, transient stability (angular stability) capability is higher than the 460 MW thermal limit of the Heywood 500/275 kV transformers under system normal operating conditions.

2. Oscillatory Stability Transfer Capability

The oscillatory stability export limit out of South Australia under light system demand, high wind generation conditions depends on the number of thermal plants online in South Australia with Power System Stabilisers installed.

System studies assessed the minimum number of conventional generators required online to maintain SA export capability above the 460 MW thermal limit of the existing Heywood interconnector and to sustain frequency and voltage control in the SA power system under low system demand and high wind generation conditions. Results confirmed that at least three independent conventional generators with their Power System Stabiliser in service are required to be online at all times in order to ensure that maximum interconnector capability is available.

2.4.2 Murraylink Interconnector

The Murraylink HVDC interconnector connects the Victorian Red Cliffs 220 kV substation to the ElectraNet 132 kV transmission system at Monash substation near Berri. The interconnector is designed to transfer 220 MW at the receiving end (Monash or Red Cliffs). Two 132 kV circuits on separate structures connect Monash to Robertstown substation via North West Bend substation. Power flows throughout the Mid North 132 kV transmission system are also influenced by Murraylink interconnector transfers.

Network limit equations that describe limitations in the Riverland region of South Australia, assuming system normal conditions, include the Murraylink interconnector flow term.

The equations also assume the Murraylink “run-back” control is operational to prevent any unacceptable overloading of ElectraNet plant and equipment.

2.4.2.1 Import Capability

The import capability of the interconnector is 220 MW for system normal summer operating conditions. However, it should be noted that the capability of the Murraylink interconnection to inject power into South Australia is also highly influenced by the ability of the Victorian transmission system to supply Murraylink. Under high load conditions in Victoria it is this factor that limits the amount of real power that can be supplied into South Australia by Murraylink. ElectraNet and AEMO have recently concluded a joint study which has included a determination of the maximum real power that can be supplied into South Australia during 10% Probability of Exceedance (10% POE) demand conditions in Victoria. A discussion relating to the joint study is included in section 5.2.

Generation installed in the Riverland 132 kV transmission system and in the eastern region of the Mid North 132 kV transmission system can potentially displace import on the Murraylink interconnector. In accordance with the Rules Schedule S5.2.5.12, generation is allowed to connect to networks and displace interconnection flows, but by no more than on a one-for-one basis.

There were four voltage stability constraint equations and eight transient stability constraint equations which bound at times during 2014 to limit the Murraylink interconnector transfer capability into South Australia.

2.4.2.2 Export Capability

The export capability of the interconnector under system normal operating conditions is defined by a thermal limit transfer capability equation. This equation is determined by AEMO and is based on plant/equipment ratings/parameters provided by ElectraNet.

Due to the complex interaction between load and generation in the different electrical sub-regions within South Australia, it is possible for the constraint on export from South Australia to Victoria via Murraylink to be located in the Mid North region.

There are no voltage and other stability limitations which govern the Murraylink interconnector transfer capability into South Australia.

3. National Transmission Network Developments and South Australian Transmission Constraints

About this chapter

Chapter 3 provides an overview of the 2014 NTNDP as it relates to ElectraNet's transmission network. It provides a discussion of the 2014 NTNDP's listed transmission network developments that relate to South Australia, and provides an analysis of the top 20 constraints that impacted on the operation of the electricity market in South Australia during 2014.

This chapter has undergone the following modifications since publication of the 2014 Transmission Annual Planning Report:

- Section 3.4 includes discussion and tables of potential market benefit projects. The equivalent information was included in chapter 7 in the 2014 edition. Note that the projects included in section 3.4 are projects that are available to be considered, but are not currently committed, pending, or proposed. All committed, pending, and proposed market benefit projects are discussed in the relevant sections of chapter 7.
- Section 3.5 is a new section that has been included to provide an indication of constraints that are forecast to affect the South Australian electricity transmission network in future years.

3.1 2014 National Transmission Network Development Plan (NTNDP)

AEMO, as the National Transmission Planner, is responsible for publication of the NTNDP. The NTNDP aims to facilitate development of an efficient national electricity network through greater co-ordination of TNSP investments, considering both potential transmission and generation development. The NTNDP seeks to influence transmission investment in a number of different ways, by:

- Providing a national focus on market benefits and transmission augmentations to support an efficient power system;
- Proposing a range of plausible future scenarios and exploring their electricity supply industry impacts, with an emphasis on identifying national transmission network limitations under those scenarios, and providing a network development outlook that will be robust across the different scenarios; and
- Identifying network needs early so the relevant TNSPs have sufficient time to explore non-network options, prepare a RIT-T, and deliver solutions in a timely manner.

The 2014 NTNDP is in essence a least-cost expansion plan that has considered potential inter-regional augmentations between the current NEM regions. Generation placement within the network is based on zones identified in the NTNDP: the zones that relate to South Australia are the Northern South Australia (NSA), Adelaide (ADE), and South East South Australia (SESA) zones.

As described in AEMO's 2012 NTNDP, the assessment of network adequacy in the NTNDP does not consider:

- Specific augmentations in case future generation does not follow the least-cost expansion;
- Intra-regional augmentations driven by economic justification;
- Augmentations based on differing planning standards;
- Ongoing local transmission needs in each zone;
- The need for local or regional transmission augmentation driven by regional or local demand growth, consideration of coincident maximum demands of individual zones or the appearance of new or contract load; and
- Replacement of aged assets.

3.2 Transmission Network Development Identified in the NTNDP

AEMO's 2014 NTNDP has classified emerging network limitations into two categories: reliability or market benefits.

AEMO has identified the limitation on the 132 kV line between Robertstown and North West Bend as an emerging reliability network limitation. Details and results of ElectraNet and AEMO's joint planning studies related to the Riverland region of South Australia are included in section 5.2.

A further five network limitations on the ElectraNet network were identified as potential market benefits limitations - this is an increase from four in the 2013 NTNDP. These limitations were identified by AEMO as occurring mainly at times of high wind generation output[12].

ElectraNet's analysis indicates that these limitations are occurring now, or expected to occur in the near future. The addition of new wind farms will increase this congestion. In particular, AEMO's forecast increase in gas prices across the east coast of Australia will reduce the level of gas power generation in South Australia. This will increase flows into South Australia across the Heywood and Murraylink interconnectors. Addressing these limitations may deliver market benefits unrelated to the level of wind generation. The emerging market benefit constraints identified in the 2014 NTNDP are:

- Lower Eyre Peninsula 132 kV network - see section 7.7.1 for further details;
- Transmission network between the Northern South Australia (NSA) and Adelaide (ADE) zones - see section 7.8.1 for further details;
- Riverland 132 kV network - see section 5.2 for further details;
- Upper South East (Tailem Bend – Tungkillo) transmission corridor - see section 5.1 for further details; and
- Lower South East to Heywood transmission corridor – see sections 7.2.2.2 for further details.

ElectraNet will continue to explore with AEMO the appropriate network developments to efficiently address network congestion.

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[12] NTNDP 2014, AEMO, page 20

3.3 Transmission Network Constraints

Constraint equations are used by AEMO to manage system security and market pricing. A constraint binds on dispatch when it alters the level of power from either a generator or an interconnector from the level which would have been dispatched if the constraint was not in place. Generators (and interconnectors) can be constrained on, above the level that would otherwise occur, or constrained down, dispatched below what would otherwise occur.

This section provides an assessment of the top 20 binding network constraints that impacted transmission network and interconnector flows on ElectraNet's transmission network during the 2014 calendar year.

When a constraint binds, AEMO publishes the marginal value of that constraint. The marginal value provides an indication of the magnitude of the impact the constraint had on market prices; however, it is only an approximation and in some instances can be misleading. At times, constraints that have a relatively small impact can report large marginal values. This is a result of the interaction of the network limitation, price at the time and the bids of generators affected by the constraint.

Table 3-1 provides the name and description of each constraint and an estimate of the annual marginal value associated with the constraint. To provide additional insight into the impact of the constraints, the hours the constraints bound during 2014 and 2013 are also presented. Note that constraints used to manage the Frequency Control Ancillary Services markets have not been included.

Many of the constraints are managing limitations and contingencies outside of South Australia. Most of them are in Victoria and come under AEMO's oversight as the National Planner and the Victorian Planner. Limitations identified in the 2014 NTNDP have been highlighted using AEMO's NTNDP naming convention in the “2014 NTNDP Reference” column.

Table 3-2 shows the top ten constraints based on the sum of the marginal value, and Table 3-3 shows the top ten constraints based on the hours the constraints have bound. These tables include commentary on future expectations regarding each constraint, including consideration of the need or otherwise for any action to alleviate the constraint.

Table 3-1: Top 20 binding constraints in 2014 affecting SA generators or interconnectors

Constraint Equation	Limitation	2014 Marginal Values (2013)	2014 Hours (2013)	Contingency	Network status	Affected SA Interconnector	2014 NTNDP Reference
NSA_S_PORxxx	Thermal: Port Lincoln Network Support Agreement	3,587,599 (1,796,463)	23.3 (19.4)	Nil	System normal	intra-regional	Economic: M-S1
S>V_NIL_NIL_RBNW	Thermal: Robertstown - North West Bend 132 kV line	2,478,435 (433,772)	239.8 (51.7)	Nil	System normal	Murraylink	Reliability: L-S1 Economic: M-S3
V>>SML_NIL_1	Thermal: Ballarat - Moorabool #1 220 kV line	1,581,992 (89,828)	28.3 (13.1)	Ballarat - Elaine - Moorabool 220 kV line	System normal	Murraylink	N/A
V>>SML_NIL_8	Thermal: Ballarat - Bendigo 220 kV line	1,181,275 (593,900)	42.4 (29.3)	Shepparton - Bendigo 220 kV line	System normal	Murraylink	Reliability: L-V1
V>>V_NIL_1B	Thermal: Dederang - Murray 330 kV line	729,653 (40,047)	10.6 (14.5)	Loss of parallel line	System normal	Murraylink	N/A
N^^V_NIL_1	Voltage: Southern NSW voltage collapse	701,455 (28,564)	208.8 (104.0)	Largest Victorian generating unit or Basslink	System normal	Murraylink	N/A
V>>V_NIL_3	Thermal: Dederang - South Morang 330 kV line	556,711 (41,437)	4.8 (1.3)	Loss of parallel line	System normal	Murraylink	N/A
S>>V_NIL_SETX_SETX	Thermal: South East transformers	291,351 (283,673)	517.4 (455.3)	Loss of the other	System normal	Heywood	Economic: M-VS1

Constraint Equation	Limitation	2014 Marginal Values (2013)	2014 Hours (2013)	Contingency	Network status	Affected SA Interconnector	2014 NTNDP Reference
V>>SML_NIL_1_5M	Thermal: Ballarat - Moorabool #1 220 kV line	175,148 (0)	2.4 (0.0)	Ballarat - Elaine - Moorabool 220 kV line	System normal	Murraylink	N/A
S>>NIL_SETB_KHTB1	Thermal: Keith - Tailem Bend #1 132 kV line	166,195 (5,916)	196.5 (26.7)	South East - Tailem Bend 275 kV line	System normal	Heywood	Economic: M-VS1
V>S_NIL_HYTX_HYTX	Thermal: Heywood transformers	159,592 (804,155)	473.9 (990.8)	Loss of other	System normal	Heywood	Economic: M-VS1
V^SML_NSWRB_2	Voltage collapse	147,459 (257,099)	62.8 (53.3)	Darlington Point - Buronga 220 kV line	Outage: NSW Murraylink runback scheme	Murraylink	N/A
S_PLN_ISL1	Thermal: Port Lincoln Network Support Agreement	143,590 (29,489)	0.9 (0.4)	Nil	System normal	intra-regional	Economic: M-S1
S_BRBG_CM	Isolated Wind farm	139,181 (0)	11.2 (0.0)	Nil	Outage: Bungama - Redhill - Brinkworth 132 kV line	intra-regional	N/A
S_PLN_ISL2	Thermal: Port Lincoln Network Support Agreement	65,308 (42,585)	0.6 (0.5)	Nil	Outage: Yadnarie – Port Lincoln 132 kV line	intra-regional	Economic: M-S1

Constraint Equation	Limitation	2014 Marginal Values (2013)	2014 Hours (2013)	Contingency	Network status	Affected SA Interconnector	2014 NTNDP Reference
V>>S_NIL_SETB_SGKH	Thermal: Snuggery - Keith 132 kV	63,809 (533,537)	287.4 (652.1)	South East - Tailem Bend 275 kV line	System normal	Heywood	Economic: M-VS1
S_LB3_0	Discretionary: limit maximum generation at Lake Bonney #3 Wind Farm to zero.	60,541 (104,857)	45.6 (155.8)	Nil	Outage	intra-regional	N/A
V>S_460	Thermal: Heywood transformers	59,053 (191,827)	159.3 (300.8)	Loss of other	System normal	Heywood	Economic: M-VS1
V>>S_NIL_KHTB2_KHTB1	Thermal: Keith - Tailem Bend #1 132 kV line	55,126 (642)	36.3 (3.3)	Keith - Tailem Bend #2 132 kV line	System normal	Heywood	Economic: M-VS1
V_HYML1_2	Voltage: limit imbalance at APD 500 kV bus	49,853 (0)	1.1 (0.0)	Nil	Outage: Heywood - Tarrone - Moorabool 500 kV line	Heywood	Economic: M-VS1

Table 3-2: Top ten constraints by marginal value

Constraint Equation	Limitation	2014 Marginal Values (2013)	Contingency	Commentary
NSA_S_PORxxx	Thermal: Port Lincoln Network Support Agreement	3,587,599 (1,796,463)	Nil	ElectraNet dispatches this generation under a network support agreement to supply the Port Lincoln load under islanded conditions The use of network support to supply Port Lincoln was recently shown to be economic in the 2013 Eyre Peninsula RIT-T assessment and will continue indefinitely, subject to annual review
S>V_NIL_NIL_RBNW	Thermal: Robertstown - North West Bend 132 kV line	2,478,435 (433,772)	Nil	The Murraylink runback control scheme allows operation of this network beyond its N-1 capability, but is insufficient to completely alleviate the constraint. The constraint binds most frequently at times of high demand in the Riverland and Western Victoria. It also binds at times of high wind generation in South Australia. Congestion will be alleviated by ElectraNet's implementation of dynamic line ratings on the Robertstown - North West Bend No. 1 132 kV line and first section of the Robertstown – North West Bend No. 2 132 kV line in 2014, and by uprating line clearances in 2015
V>>SML_NIL_1	Thermal: Ballarat - Moorabool #1 220 kV line	1,581,992 (89,828)	Ballarat - Elaine - Moorabool 220 kV line	AEMO have applied the RIT-T to this constraint. The preferred option identified in the PACR published in October 2013 consists of three stages: • Install a wind monitoring facility on the Ballarat – Bendigo 220 kV line in 2015-16 (stage 1); • Install a third Moorabool – Ballarat 220 kV circuit in 2017-18 (stage 2); and • Uprate the Ballarat – Bendigo 220 kV to a maximum operating temperature of 82 ˚C in 2019-20 (stage 3) An update to the PACR that was published in June 2014 re-assessed stage 3 based on further proposals from network and non-network service providers. It yielded a small difference in net market benefits between the network solution previously identified compared to the best available non-network solutions[13]

[13] AEMO 2014 Victorian Transmission Annual Planning Report, pages 45 – 47.

Constraint Equation	Limitation	2014 Marginal Values (2013)	Contingency	Commentary
V>>SML_NIL_8	Thermal: Ballarat - Bendigo 220 kV line	1,181,275 (593,900)	Shepparton - Bendigo 220 kV line	As previously described for constraint equation V>>SML_NIL_1
V>>V_NIL_1B	Thermal: Dederang - Murray 330 kV line	729,653 (40,047)	Loss of parallel line	AEMO is monitoring this limitation. The 2014 Victorian Transmission Annual Planning report considered two options: • A third 1,060 MVA 330 kV line between Murray and Dederang with an estimated cost of $183 Million; or • A second 330 kV line from Dederang to Jindera with an estimated cost of $121 Million AEMO's 2013 and 2014 NTNDPs did not identify additional interconnector capacity in the least cost generation and transmission expansion study, and as such no requirement for this upgrade was noted[14] The 2014 NTNDP modelling considered two upgrades to the Victoria to NSW interconnector.[15,16] Option 1 had an estimated cost of $3 billion and included a double circuit 500 kV line from South Morang to Bannaby. Option 2 (referred to as Option 3) had an estimated cost of $210 Million and included: • Uprate Upper Tumut-Canberra and Upper Tumut-Yass 330 kV lines; • Uprate South Morang-Dederang 330 kV lines and series capacitors; • Uprate Eildon-Thomastown 220 kV line; • A fourth 330/220 kV Dederang transformer; • Series compensation on Eildon-Thomastown 220 kV line; and • Phase angle regulator on the Bendigo-Shepparton 220 kV line

14 AEMO 2014 Victorian Transmission Annual Planning Report, page 52 Table E-3
15 AEMO 2014 Plexos LT Model and traces
16 AEMO 2014 Planning Studies Additional Modelling Data

Constraint Equation	Limitation	2014 Marginal Values (2013)	Contingency	Commentary
N^^V_NIL_1	Voltage: Southern NSW voltage collapse	701,455 (28,564)	Largest Victorian generating unit or Basslink	AEMO monitors and checks the time periods when this constraint binds
V>>V_NIL_3	Thermal: Dederang - South Morang 330 kV line	556,711 (41,437)	Loss of parallel line	AEMO is monitoring this limitation. The Victorian Transmission Annual Planning report 2014 has considered two options: • Up-rate the two existing lines and series compensation at an estimated cost of $15.9 Million • A third 330 kV 1060 MVA single circuit link between Dederang and South Morang with 50% series compensation at an estimated cost of $340.7 Million (excluding easement costs) AEMO's NTNDP did not identify additional interconnector capacity in the least cost generation and transmission expansion study, and as such no requirement for this upgrade was noted[17] The 2014 NTNDP modelling considered two upgrades to the Victoria to NSW interconnector, as previously described for constraint V>>V_NIL_1B
S>>V_NIL_SETX_SETX	Thermal: South East transformers	291,351 (283,673)	Loss of the other	ElectraNet has applied emergency loading limits to the South East transformers, which has permitted the 15-minute rating of the South East transformers to be increased. See section 5.5 for further details A control scheme to manage this constraint is under development and expected to be in service in 2015. The control scheme will involve runback/trip of Lake Bonney generation following the trip of a transformer at South East substation, when the loading on the transformer exceeds the emergency loading limit of the remaining transformer. See section 7.2.2.2 for further details

[17] AEMO, 2014, Victorian TAPR, page 52 Table E-3

Constraint Equation	Limitation	2014 Marginal Values (2013)	Contingency	Commentary
V>>SML_NIL_1_5M	Thermal: Ballarat - Moorabool #1 220 kV line	175,148 (0)	Ballarat - Elaine - Moorabool 220 kV line	As previously described for constraint equation V>>SML_NIL_1
S>>NIL_SETB_KHTB1	Thermal: Keith - Tailem Bend #1 132 kV line	166,195 (5,916)	South East - Tailem Bend 275 kV line	The constraint is due to a weak transmission link in the South East to Tailem Bend corridor. Congestion will be alleviated by Heywood interconnector upgrade. See section 7.2.2.2 for further details

Table 3-3: Top ten constraints by duration

Constraint Equation	Limitation	2014 Hours (2013)	Contingency	Commentary
S>>V_NIL_SETX_SETX	Thermal: South East transformers	517.4 (455.3)	Loss of the other	ElectraNet has applied emergency loading limits to the South East transformers, which has permitted the 15-minute rating of the South East transformers to be increased. See section 5.5 for further details A control scheme to manage this constraint is under development and expected to be in service in 2015. The control scheme will involve runback/trip of Lake Bonney generation following the trip of a transformer at South East substation, when the loading on the transformer exceeds the emergency loading limit of the remaining transformer. See section 7.2.2.2 for further details
V>>V_NIL_2B_R	Thermal: South Morang 500/330 kV F2 Transformer	515.8 (94.2)	Nil	AEMO is monitoring this limitation. The 2014 Victorian Transmission Annual Planning Report considered two options: • A second 1000 MVA 500/330 kV transformer at a cost of $56.5 Million plus any fault level mitigation works; or • A new 1000 MVA 500/220 kV transformer at South Morang and connection of the Thomastown - Rowville 220 kV line at South Morang at an estimated cost of $74 Million plus any fault level mitigation works AEMO has not identified a requirement for this upgrade[18]
V>S_NIL_HYTX_HYTX	Thermal: Heywood Transformers	473.9 (990.8)	Loss of the other	Congestion will be alleviated by the Heywood Interconnector upgrade. See section 7.2.2.2for further details
V>>V_NIL_2A_R	Thermal: South Morang 500/330 kV F2 Transformer	310.8 (88.4)	Nil	As previously described for constraint equation V>>V_NIL_2B_R (above)

[18] AEMO Victorian Annual Planning Report, 2014, page 59, table E-8

Constraint Equation	Limitation	2014 Hours (2013)	Contingency	Commentary
V>>S_NIL_SETB_SGKH	Thermal: Snuggery - Keith 132 kV line	287.4 (652.1)	South East - Tailem Bend 275 kV line	The constraint is due to a weak transmission link in the South East to Tailem Bend corridor. Congestion will be alleviated by Heywood interconnector upgrade. See section 7.2.2.2 for further details
S>V_NIL_NIL_RBNW	Thermal: Robertstown - North West Bend 132 kV line	239.8 (51.7)	Nil	The Murraylink runback control scheme allows operation of this network beyond its N-1 capability, but is insufficient to completely alleviate the constraint. The constraint binds most frequently at times of high demand in the Riverland and Western Victoria. It also binds at times of high wind generation in South Australia. Congestion will be alleviated by ElectraNet's implementation of dynamic line ratings on the Robertstown - North West Bend No. 1 132 kV line and first section of the Robertstown – North West Bend No. 2 132 kV line in 2014, and by uprating line clearances in 2015 (refer to section 7.2.2)
V::N_NIL_V4	Transient stability	236.2 (0.0)	Loss of Heywood - South Morang 500 kV line	AEMO monitors and checks the time periods when this constraint binds
N^^V_NIL_1	Voltage: Southern NSW voltage collapse	208.8 (104.0)	Largest Victorian generating unit or Basslink	AEMO monitors and checks the time periods when this constraint binds
S>>NIL_SETB_KHTB1	Thermal: Keith - Tailem Bend #1 132 kV line	196.5 (26.7)	South East - Tailem Bend 275 kV line	The constraint is due to a weak transmission link in the South East to Tailem Bend corridor. Congestion will be alleviated by Heywood interconnector upgrade. See section 7.2.2.2 for further details
V^^S_NIL_MAXG_AUTO	Voltage: South East SA voltage stability limit	178.6 (147.8)	Largest South Australian generating unit	This constraint will be relieved by the addition of 50% series compensation at Black Range to the South East to Tailem Bend 275 kV lines. See section 7.2.2.2 for further details. Following commissioning of the series compensation, it is expected that this constraint will continue to bind at times, but at a higher level than for present-day conditions

3.4 Network Market Benefit Projects

A range of factors can impact on the efficient development and operation of the transmission network, such as: the connection of significant new loads, a change in the nature of the generation fleet (perhaps driven by climate change policies), or higher gas prices.

Such developments may lead to network constraints that are efficient to build out with network developments (or non-network alternatives) that provide a net market benefit.

Table 3-4 and Table 3-5 list potential future inter and intra-regional market benefit projects, respectively.

Some of the projects listed in Table 3-4 and Table 3-5 would be required if the network develops according to the most recent NTNDP generator expansion. Other projects may be warranted if either the least cost generator expansion changes or actual generator investment decisions do not follow the NTNDP generator expansion.

The specific projects that will provide net market benefits, and the timeframe in which they will do so, is often uncertain until actual generator investment decisions are made or there is sufficient information available to proceed with a RIT-T. Because of this uncertainty, project timings have not been proposed or presented.

The potential future projects listed below in Table 3-4 and Table 3-5, whilst high level, have been identified through constraint and planning analysis. ElectraNet expects that these projects will reduce future network congestion and hence may deliver sufficient benefits to customers to warrant development. These projects may also lead to minor improvements in network reliability. Project costs are indicative only and are aligned to the 2014 NTNDP generator expansion plan, which is presented in Appendix B.

Table 3-4: Potential inter-regional market benefit projects

Project name	Drivers/value of potential project	Description of potential project	Capacity/ Benefit provided	Lead time	Cost ($M)
Upper South East network augmentation	Increased generation injection at Tailem Bend or Tepko or market driven requirement for increased interconnector capacity in either direction	String vacant 275 kV circuit between Tailem Bend and Tungkillo	400-600 MW increase in line section capacity	2 years RIT-T 2 years delivery	40-60
Strengthen Riverland transmission corridor	Augmentation may reduce losses, support development of renewable generation, improve export/import capability and enhance reliability to the Riverland in South Australia and Western Victoria	Rebuild Robertstown - North West Bend - Monash as high capacity 275 kV AC double circuit line Extend network into Victoria or New South Wales, AC or HVDC options available	>400 MW capacity increase.	2 years RIT-T 5 years detailed design and delivery (ElectraNet)	200-400 (ElectraNet costs)

Table 3-5: Potential intra-regional market benefit projects

Project name	Drivers/value of potential project	Description of potential project	Capacity/Benefit provided	Lead time	Cost ($M)
Strengthen Mid North 275 kV network	Increase in renewable generation in the Mid North or Eyre Peninsula	Various line uprating and dynamic line ratings dependent on generator developments	Capacity increase depending on location of generation and local network capability	2-3 years	< 5
Reconfigure Mid North 132 kV network	Increased renewable generation on the Mid North network	Various potential reconfiguration options dependent on generator and load developments	Capacity increase depending on location of generation and load	Dependent on location of generation and load	Dependent on location of generation and load
Tie Davenport – Robertstown 275 kV at Belalie substation	Increased renewable generation on the mid-north network	Tie Davenport to Robertstown 275 kV at Belalie	Capacity increase depending on location of generation	2 RIT-T 2 years detailed design and delivery	10–20
Tie Robertstown – Para 275 kV at Tungkillo substation	Increased renewable generation on the mid-north network	Tie Robertstown to Para 275 kV at Tungkillo	Capacity increase depending on location of generation	2 years	5–10
Davenport - Brinkworth - Para 275 kV	Increase in renewable generation and loads through the Mid North and Eyre Peninsula	Rebuild Davenport-Brinkworth-Para 275 kV as a high capacity 275 kV AC double circuit line with twin conductors	1200 MW capacity increase	2 RIT-T 5 years easement acquisition, detailed design and delivery	300–400

3.5 Future network congestion

The committed upgrades of the Heywood interconnector and of the Robertstown to North West Bend #1 132 kV line will increase the capability of the ElectraNet network to import and export power across both interconnectors. Following this increase in capability, the generally higher flows across both interconnector corridors are expected to, at times, be constrained by the following network limitations.

Import limitations are expected to occur most frequently across the Heywood corridor. The limitations expected to bind most frequently are:

- Thermal ratings of 275 kV lines in the upper South East between Tailem Bend and Tungkillo;
- Thermal ratings of 275 kV lines in the lower South East between Tailem Bend and Heywood; and
- Voltage stability limitations in the South East.

Export limitations are also expected to occur frequently across both interconnector corridors. The limitations expected to bind most frequently are:

- Thermal ratings of 275 kV lines in the upper South East between Tailem Bend and Tungkillo;
- Thermal ratings of 275 kV lines in the lower South East between South East and Heywood ;
- Thermal ratings of 132 kV lines in the Mid North between Waterloo East and Robertstown;
- Thermal ratings of 132 kV lines in the Mid North between Robertstown and North West Bend;
- Voltage limitations at North West Bend, Berri and Monash; and
- Transient instability between South Australia and the rest of the NEM.

Partly depending on outcomes with the Renewable Energy Target, South Australia has the potential to see a further increase in connected renewable generation. Depending on the location of these connections, different network congestion patterns are likely to emerge. In addition to the limitations listed above, the limitations expected to bind are:

- Thermal ratings of 275 kV lines in the Mid North between Davenport and Robertstown;
- Thermal ratings of 275 kV lines in the Mid North between Davenport and Brinkworth;
- Thermal ratings of 132 kV lines in the Mid North between Waterloo and Templers; and
- Thermal ratings of the 275/132 kV Robertstown transformers.

Table 3-6 summarises forecast future limitations on ElectraNet's electricity transmission network. Where possible, it provides references to other sections of this Report that contain information regarding projects or initiatives that will resolve or mitigate the forecast limitations.

Table 3-6: Summary of Forecast Future South Australian Transmission Network Congestion

Limitation	Affected interconnector	Import or export	Reference to potential mitigating project(s)
Thermal ratings of 275 kV lines in the upper South East between Tailem Bend and Tungkillo	Heywood	Import and export	Sections 7.8.4 and 7.8.5
Thermal ratings of 275 kV lines in the lower South East between Tailem Bend and Heywood	Heywood	Import and export	Section 7.8.4
Thermal ratings of 132 kV lines in the Mid North between Waterloo East and Robertstown	Murraylink	Export	Section 7.8.3
Thermal ratings of 132 kV lines in the Mid North between Robertstown and North West Bend	Murraylink	Export	
Voltage stability limitations in the South East	Heywood	Import and export	
Voltage limitations at North West Bend, Berri and Monash	Murraylink	Export	Section 7.8.6
Transient instability between South Australia and the rest of the NEM	Both	Import and export	
Thermal ratings of 275 kV lines in the Mid North between Davenport and Robertstown	Intra-regional	N/A	Section 7.8.1
Thermal ratings of 275 kV lines in the Mid North between Davenport and Brinkworth	Intra-regional	N/A	
Thermal ratings of 132 kV lines in the Mid North between Waterloo and Templers	Intra-regional	N/A	Section 7.8.3
Thermal ratings of the 275/132 kV Robertstown transformers	Intraregional and Murraylink	Export	Section 7.8.2

Congestion in Victoria frequently impacts the transfer capability of the Heywood and Murraylink interconnectors. This will occur more often as the capability of the network in South Australia increases and become more evident with increases in renewable generation in South Australia. The most significant limitations in Victoria that will affect the ability of South Australian plant to export power are expected to be:

- 220 kV limitations in country Victoria (impacts Murraylink);
- 330 kV limitations on Victoria to NSW exports (impacts Murraylink);
- South Morang 500/330 kV transformer limitations in Victoria (impacts Heywood); and
- Transient stability limitations on exports to South Australia (impacts Heywood).

4. Demand Forecasts and Summer Review

About this chapter

Chapter 4 provides information regarding demand forecasts, along with a review of observed demands over the 2014-15 summer.

Schedule 5.7 of the Rules sets out the demand forecast information each registered participant connected to ElectraNet's network is required to provide on an annual basis. This includes information on:

- Load diversity;
- Winter peaks;
- Daily load profiles; and
- Average conditions for January, April, July and October for weekdays, Saturdays, Sundays and public holidays.

Given that connection points in South Australia experience maximum demands in summer, winter maximum demands are neither collected by ElectraNet, nor used for planning purposes. ElectraNet does not publish this information.

This year, ElectraNet has published details of the demand forecast used for preparation of this Transmission Annual Planning Report in the South Australian Connection Point Forecasts Report[19]. That report includes details regarding:

- Maximum historical and forecast demand at each connection point;
- Load diversity between connection points;
- Peak daily load profiles for each connection point; and
- A reconciliation between ElectraNet's connection point demand forecasts and AEMO's South Australian forecast from the 2014 National Electricity Forecast Report.

ElectraNet provides transmission services to electricity consumers via the SA Power Networks' distribution network, as well as other customers, including generators that have a direct connection to ElectraNet's transmission network.

The electrical loading on components of the transmission system is determined primarily by the location and output of generating plant, system configuration, and electricity demand.

[19] Available at http://www.electranet.com.au/network/transmission-planning/south-australian-connection-point-forecasts-report/.

4.1 Demand forecast

Due to lead times in the delivery of transmission system projects, it is necessary to forecast electricity demand and loading conditions into the future.

As the need for transmission reinforcement is often localised, it is also necessary to construct a demand forecast for every connection point on the transmission system.

ElectraNet considers that its customers are best placed to understand their needs. Given this, and in accordance with Rules clause 5.11.1, ElectraNet annually receives 10 year demand forecasts from SA Power Networks and direct connect customers. ElectraNet and SA Power Networks work together to determine and agree on any adjustments required to account for externalities such as embedded generators and major customer loads.

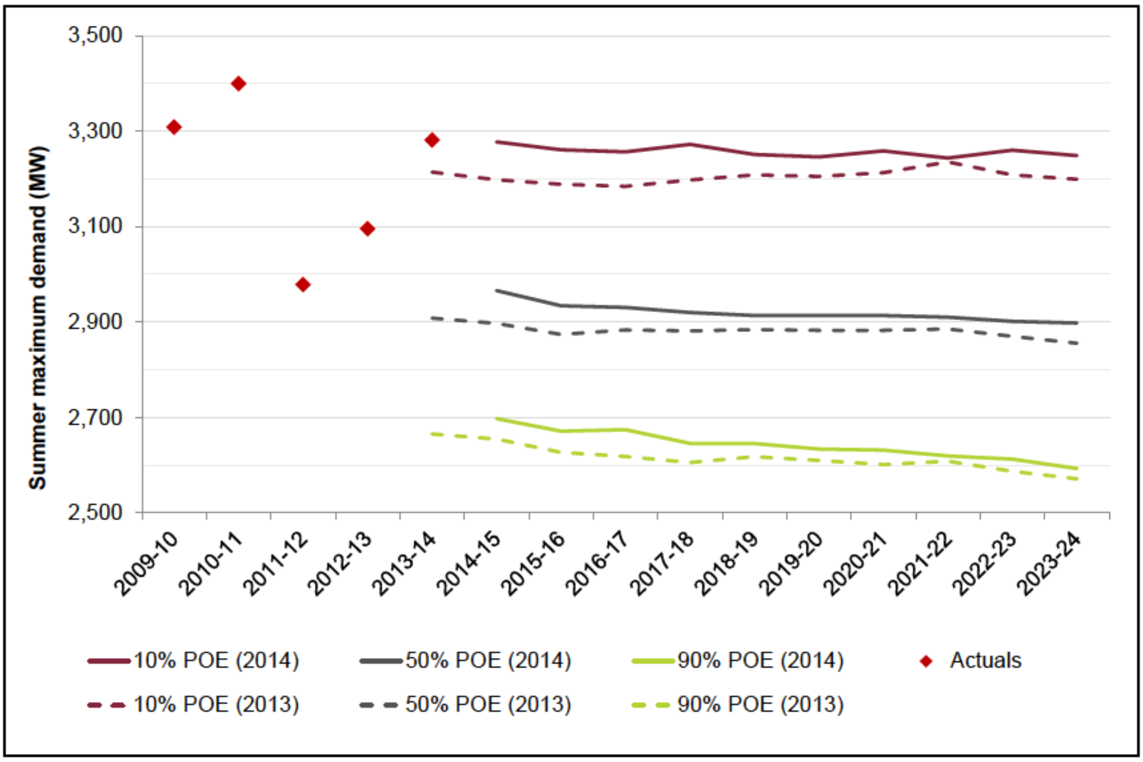
ElectraNet published the South Australian Connection Point Forecasts Report[20] in February 2015. This report sets out the demand forecasts that are used in the 2015 Transmission Annual Planning Report and includes a reconciliation of demand forecasts with AEMO's 2014 National Electricity Forecast Report (NEFR). The remainder of this chapter summarises some of the information presented in that report.

4.1.1 Review of 2014 National Electricity Forecasting Report

AEMO publishes an annual state-wide demand forecast for South Australia. Since 2013, AEMO has published the South Australian forecast as part of the NEFR.

In 2014, AEMO forecast that state-wide demand would decline on average by 1.1 per cent per annum until 2016-17. From 2016-17, AEMO's 10% POE demands are forecast to generally hold steady until 2023-24. This demand trend is similar to that presented in the 2013 NEFR, although the starting point has been lifted slightly following observations from the 2013-14 summer which exceeded the 2013 NEFR's 10% POE forecast. Figure 4-1 shows AEMO's 2014 NEFR 10%, 50% and 90% POE medium forecast for South Australia. Also shown is the 2013 NEFR forecast as well as the actual state-wide maxima over the last five years.

[20] Available at http://www.electranet.com.au/network/transmission-planning/south-australian-connection-point-forecasts-report/.



Source: AEMO 2014 NEFR SA Operational Demand

Figure 4-1: AEMO's 2014 SA medium demand forecasts

4.1.2 AEMO's Connection Point Forecasts

In December 2014, AEMO published connection point forecasts for South Australia for the first time. Additional information on AEMO's methodology for connection point forecasting can be found on AEMO's website[21].

At an aggregate level, AEMO's and ElectraNet's connection point forecasts reconcile reasonably closely. This is demonstrated in the comparison provided in Appendix A of the 2015 SA Connection Point Forecasts Report. Whilst a comparison of the individual connection point forecasts indicates that there are some differences between the two at a connection point level, neither forecast is consistently higher or lower than the other.

Planning analysis has shown that the difference between the ElectraNet and AEMO connection point forecasts has no impact on network development plans within the next ten years.

4.1.3 Reconciliation

ElectraNet uses both the AEMO state-wide forecasts and SA Power Networks' connection point forecasts depending on the particular needs of a planning study.

Figure 4-2 demonstrates the close reconciliation between ElectraNet's diversified state-side maximum demand forecast compared to AEMO's 2014 NEFR state-wide forecast.

[21] Available at http://aemo.com.au/Electricity/Planning/Forecasting/AEMO-Transmission-Connection-Point-Forecasting.

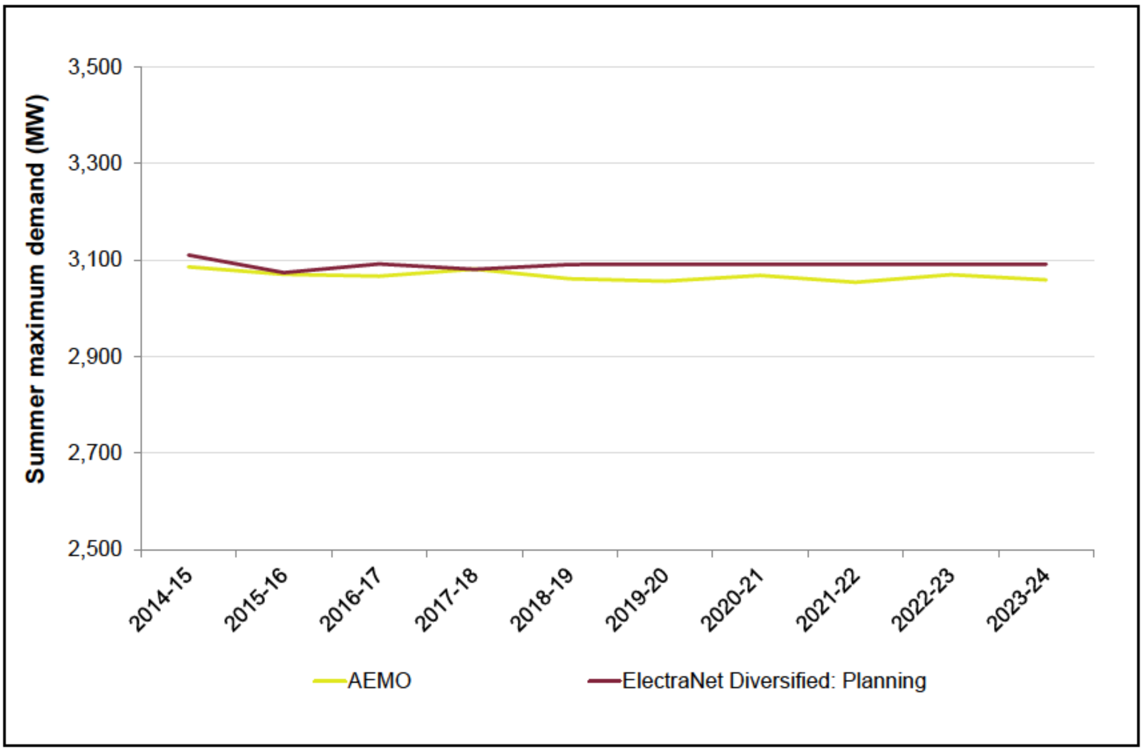


Figure 4-2: ElectraNet reconciliation with AEMO's state-wide forecast

4.2 Summer Review

4.2.1 State-wide

Temperatures over the summer are a key driver of maximum demand for electricity. Consecutive days of high temperatures, such as those that make up a typical summer heat wave, drive state-wide demands to levels of more than double the average demand. The holiday period that begins at Christmas time and extends until Australia Day reduces the magnitude of the temperature impact on demand, as do other calendar effects such as weekends and public holidays.

For state-wide electricity demand to reach high levels, metropolitan Adelaide needs to experience high temperatures during summer, generally on a weekday outside of the holiday period. Individual connection points may also experience isolated heat events, driving high localised demands independent of state-wide demand levels.

Overall 2014-15 summer temperatures were quite mild around metropolitan Adelaide. High temperatures conditions were experienced in early January 2015 accompanied by significant bushfire events in the Adelaide Hills. However, despite this, no heat events occurred of sufficient intensity and duration to cause extreme electricity demand outcomes. February experienced average daily maximums above the long term trend with a ten day period between 6 February and 15 February experiencing daily maximum temperatures above 30 degrees. February's maximum reached 41.6 degrees on Saturday 14 February and reached 40.0 degrees on Sunday 22 February which was the fourth consecutive day above 35 degrees before a cool change arrived. With days 3 and 4 of this heat event occurring over the weekend, extreme electricity demand did not occur, nor was it expected.

Table 4-1 sets out historical monthly trends and a comparison to summer 2014-15.

Table 4-1: Long term summer trends and comparison with summer 2014-15

	December	January	February	March
Long term trend				
Max Temperature	43.4[22]	45.7	44.7	41.9
Date of maximum	19-12-2013	28-01-2009	02-02-2014	06-03-1986
Average Max Temperature	27.1	29.4	29.5	26.4
Mean days > 30 ˚C	9.6	13.4	12.6	7.9
Mean days > 35 ˚C	3.3	6.1	5.5	2.6
Mean days > 40 ˚C	0.6	1.8	0.9	0.2
Summer 14-15				
Peak temperature	36.1	44.1	41.6	33.6
Date of maximum	21-12-2014	2-01-2015	14-02-2015	16-03-2015
Average max temperatures	27	28.7	32.7	26.2
Difference between 2014-15 average Max and long term trend.	0.1	-0.7	3.2	-0.2
Days > 30 ˚C	7	11	18	3
Days > 35 ˚C	2	5	10	0
Days > 40 ˚C	0	2	2	0

The state-wide demand reached a maximum of 2,830 MW, on Wednesday 7 January 2015. Demand exceeded 2,500 MW on six occasions during the 2014-15 summer.

Table 4-2 below shows the dates on which demand exceeded 2,500 MW and the temperature demand index on those days.

A key high-level indicator is the temperature demand index. The index is a metric that identifies the temperature patterns that have the potential to deliver a 10% POE demand level. SA Power Networks has previously determined that a threshold value of 38 (comprised of a 67% weighting to the day's maximum temperature, 18% weighting to the overnight minimum and a 15% weighting to the previous day's average temperature) occurring after Australia Day, provides the necessary temperature conditions to achieve this level of demand at a state level.

This analysis has been conducted over 100 years and found that 19 events have exceeded this threshold over a ten week period from 20 December to the end of February. Half of this period includes the summer holiday period and weekends. Hence, over the last 100 years, it can be assumed there have been 9-10 weather events above this threshold at times that are expected to result in 10% POE demand conditions. As high demand is primarily driven by extreme temperature conditions during non-holiday periods, a temperature index above 38 on a working day has been considered an appropriate indicator of 10% POE demand conditions[23].

22 Updated Bureau of Meteorology data – differs from previous Bureau of Meteorology data reported in the 2014 Transmission Annual Planning Report.

23 Review of ElectraNet's Revised Demand Forecasts, Oakley Greenwood, January 2013

Table 4-2: Highest demand periods in summer 2014-15

Date	Temperature demand Index[24]	Maximum demand
Friday 2 January	38.0	2,699
Tuesday 6 January	34.2	2,593
Wednesday 7 January	37.2	2,830
Saturday 14 February	36.7	2,641
Friday 20 February	34.1	2,635
Saturday 21 February	35.2	2,614
Sunday 22 February	35.8	2,737

Figure 4-3 below shows the temperature index for all days over the summer demonstrating the relative mildness of the summer, with the temperature demand index reaching 38 only once. That event occurred during the holiday period. The highest value of the temperature index on a weekday outside the holiday period occurred on Friday 20 February, when the index reached 34 and demand reached 2,635 MW.

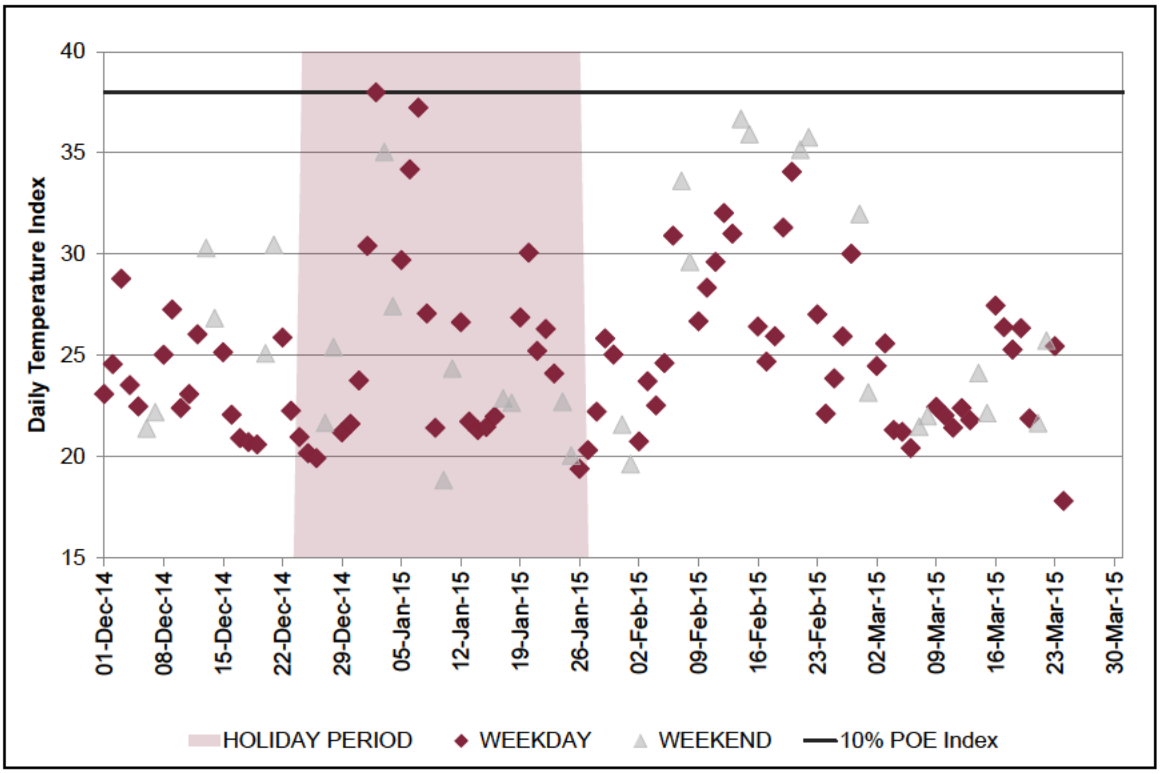


Figure 4-3: Summer 2014-15 daily temperature index

[24] For calculation of the temperature demand index, ElectraNet has calculated the previous day's average temperature using the average of the 24 hourly temperature readings.

4.2.2 Connection Point Review

Table 4-3 lists the connection points that met or exceeded either ElectraNet's 10% POE connection point demand forecasts or AEMO's 10% POE connection point demand forecasts, and shows the date and time at which the maximum connection point demand was recorded.

It can be seen that:

- Mannum and Whyalla exceeded both ElectraNet's and AEMO's 10% POE demand forecasts;
- Kadina East and Wudinna exceeded ElectraNet's 10% POE demand forecasts but not AEMO's; and
- Ardrossan West, Berri, and Dalrymple met or exceeded AEMO's 10% POE demand forecasts but not ElectraNet's.

Table 4-3: Connection points meeting or exceeding the medium 10% POE demand forecast

	ElectraNet 10% POE demand forecast (MW)	AEMO 10% POE forecast (MW)	Actual Maximum (MW)	Date and time (Australian Central Daylight Time) of maximum demand
Ardrossan West	12.0	11.7	**11.7**	Friday 2 January 7 pm
Berri	94.8	87.0	**87.6**	Sunday 15 February 6.30 pm
Dalrymple	7.9	7.5	**7.6**	Friday 2 January 7.30 pm
Kadina East	24.7	26.0	**25.4**	Friday 2 January 7.30 pm
Mannum	12.3	11.9	**13.9**	Friday 2 January 8 pm
Whyalla	73.5	73.7	**74.1**	Saturday 14 February 8.30 pm
Wudinna	13.9	14.6	**14.0**	Saturday 14 February 8 pm

5. Significant Planning Investigations

About this chapter

This chapter documents the progress and findings of significant planning investigations that ElectraNet has progressed, undertaken or been involved in since the publication of the 2014 Transmission Annual Planning Report. These include:

- Upper South East Transmission Corridor Market Benefit Study;
- Murraylink Support to SA Riverland: Joint ElectraNet - AEMO Study;
- Renewable Generation Integration: Joint ElectraNet - AEMO Study;
- Frequency Control Following Separation of South Australia from the NEM; and
- Transformer and Transmission Line Thermal Ratings Review.

Section 5.6 has been added to provide an outline of planned and recently commenced strategic studies. Studies that are planned to assist with the integration of the Heywood Interconnector Upgrade project are described in that section.

Findings from significant planning investigations were reported in chapter 4 of the 2014 Transmission Annual Planning Report.

5.1 Upper South East Transmission Corridor Market Benefit Study

ElectraNet has investigated transmission constraints that will occur after the Heywood Interconnector has been upgraded in 2016. The Heywood Interconnector Upgrade RIT-T (Heywood RIT-T) and subsequent planning studies have identified that congestion on the interconnector into South Australia will tend to occur in the following locations in order of severity:

- North of Tailem Bend, between Tailem Bend and Tungkillo on the 275 kV network and between Tailem Bend and Mobilong on the 132 kV network; and
- Between Tailem Bend and Heywood on the 275 kV network.

Since the Heywood RIT-T, forecasts for the east coast domestic gas prices, including South Australia, have increased in the short to medium term. Whilst the Heywood RIT-T explored multiple gas price trajectories, current forecasts from AEMO predict higher gas prices than were tested in the Heywood RIT-T. As about half of South Australia's electricity comes from gas fired generation[25], such increases in the gas price will result in an increase in flows across the interconnectors from Victoria[26] due to increased imports of cheaper coal generated electricity.

While early indications as reported in 2014 suggested that forecast higher gas prices could make a further interconnector upgrade economic, more detailed investigation has shown this not to be the case at this time. However, ElectraNet is exploring lower cost opportunities to improve equipment ratings that would help to minimise the above network constraints.

[25] 2014, AEMO South Australian Historical Market Information, Figure 1
[26] 2014, AEMO South Australian Electricity Market Economic Trends, Table 3

ElectraNet will also continue to monitor the drivers of congestion to identify the appropriate time for a further upgrade of the interconnector.

5.2 Murraylink Support to South Australian Riverland and Regional Victoria: Joint ElectraNet – AEMO Study

ElectraNet and AEMO have performed a study on the capability of the South Australian Riverland 132 kV network and the Regional Victorian 220 kV network to meet reliability requirements and support transfers on the Murraylink 220 MW HVDC Interconnector. The study has considered a range of network augmentation options, associated development costs and timeframes that provide increased transfer capacity across the Murraylink Interconnector.

The recommendations of the joint study are that:

- ElectraNet implement dynamic line ratings on the Robertstown – North West Bend No. 1 132 kV line as soon as possible (to be completed in the first half of 2015);
- Increase line clearance on the Robertstown - North West Bend No 1 132 kV line thereby improving the summer thermal rating from 110 MVA to 141 MVA as soon as possible (due to be completed before summer 2015/16);
- AEMO continue to refine and implement the preferred option identified by the Regional Victorian Thermal Capacity Upgrade RIT-T; and
- ElectraNet and AEMO continue to jointly monitor the need for and ability of Murraylink to provide capacity support for both the South Australian Riverland 132 kV network and the Regional Victorian 220 kV network in future years.

These recommendations are consistent with the 2014 NTNDP, which identified transfer limitations on the Robertstown - North West Bend No. 1 132 kV line and advised the potential need for additional capacity along the Riverland region 132 kV transmission corridor.

The outcomes of this study have been incorporated into the network development plans for the Riverland region. The short-term ElectraNet projects resulting from the study (completed and committed) are discussed further in Chapter 7.

5.3 Renewable Generation Integration: Joint ElectraNet – AEMO Study

In recent years, renewable energy generation has increased as a proportion of the total generation mix across all NEM regions. In particular, South Australia has by far the highest renewable energy penetration of any NEM region. The availability of abundant high-quality wind and solar resource in South Australia, facilitated by affirmative State and Federal government policies to encourage the uptake of renewable power generation such as the Renewable Energy Target, has led to a significant growth in renewable generation in South Australia over the last 10 years. As of 31 January 2015, South Australia has 1474 MW of wind[27] and about 580 MW of rooftop solar PV generation installed, which are very high penetration rates when compared with the average state demand in 2014 of about 1540 MW.

[27] South Australian Wind Study Report, AEMO, p. 21. Published October 2014. Available at http://www.aemo.com.au/Electricity/Planning/South-Australian-Advisory-Functions/South-Australian-Wind-Study-Report

Conventional thermal generation has historically played an important role in ensuring that the South Australian power system is able to survive major disturbances to the power system, including separation of South Australia from the rest of the NEM. Conventional synchronous generators traditionally contribute to power system security through frequency control, inertia, reactive power support and high fault-level capability.

A joint study between ElectraNet and AEMO to investigate the impact of renewables on the South Australian power network was reported on in 2014. The report concluded that the South Australian power system can operate securely and reliably with a high proportion of renewable generation, including in situations where wind generation comprises more than 100% of state demand, as long as the following two key factors apply:

- Both circuits of the Heywood Interconnector linking South Australia and Victoria are in-service; and
- At least one synchronous generator (e.g. Northern Power Station, Osborne, Pelican Point or Torrens Island) is connected and operating in South Australia.

A very low probability scenario is a state-wide power outage if both of the Heywood Interconnector circuits are simultaneously disconnected for any reason when all synchronous generators are offline. While the risk of the interconnector failing is very low, this possibility needs to be considered as a potential risk if a synchronous generator is not online at the same time.

A significant unknown is the response of distributed rooftop solar PV in South Australia during frequency disturbances. Distributed PV was not included in the 2014 renewable integration study due to the lack of a robust and acceptable analytical methodology for representing distributed solar PV in the analysis.

Based on the findings of this joint study report, AEMO and ElectraNet are further investigating options to provide both short-term and longer-term remedies to support higher levels of renewable generation in South Australia, and to mitigate the risk and impact of a state-wide power outage in the unlikely event that South Australia should become disconnected from the NEM. Future studies being considered include:

- investigating the potential inertial contribution from existing wind generation in South Australia;
- improving the models of rooftop solar PV in power system simulations to better understand its impact on power system operation;
- determining if there are minimum levels of synchronous generation required in South Australia;
- investigating the benefits of new ancillary service markets, such as localised provision of inertia and frequency regulation;
- analysing potential augmentation options such as high inertia synchronous condensers; and
- exploring modifications to the controls of the Murraylink HVDC interconnector to enable it to provide a rapid active power response in the event that South Australia is separated from the NEM.

5.4 Frequency Control Following Separation of South Australia from the NEM

The separation of South Australia from the NEM constitutes a significant event that requires post-contingency control systems to ensure the continuing operation and security of the islanded South Australian network.

Under-frequency Load Shedding (UFLS) and Over-frequency Generator Shedding (OFGS) schemes are the primary control measures widely utilised to manage system separation events and maintain viable frequency operation of the isolated systems.

Studies conducted in 2013-14 at ElectraNet to assess the effectiveness of the UFLS concluded that the existing UFLS scheme is effective in facilitating recovery of the South Australian system frequency under a wide range of South Australian demand scenarios under import conditions. However, post-contingency transient over-voltages above 110 % of the nominal voltage level can occur on the high voltage transmission network under high South Australian demand and high South Australian import conditions.

Conversely, AEMO in 2013-14 proposed an OFGS scheme to address the issue of South Australian system over-frequencies following separation of the South Australian system under high South Australian export conditions, particularly under light South Australian system demand conditions with high levels of South Australian wind generation. The scheme features progressive tripping of wind generation in order to restore system frequency.

ElectraNet has undertaken an assessment of the effectiveness and impact of the OFGS scheme under various South Australian operating conditions and future scenarios. Preliminary results using detailed dynamic system analysis indicate that the proposed OFGS scheme is capable of restoring South Australian system frequency to within acceptable Frequency Operating Standards under South Australian system light loads with high wind generation and current 460 MW Heywood interconnector export conditions, without excessive tripping of wind generation. Further studies are ongoing to assess scenarios following the upgrade of Heywood interconnector transfer capacity to 650 MW, as well as the impact of additional recent and future wind generation capacity in South Australia on the effectiveness of the proposed OFGS scheme.

5.5 Transformer and Transmission Line Thermal Ratings Review

In recent years ElectraNet has reviewed its transmission line and transformer ratings, with a view to allowing additional network transfer capacity above that possible when using historic static equipment ratings. The main focus of this review has been on making better use of real-time information that is now available to make rating decisions.

Where it is technically viable, short term ratings will be applied to both transmission lines and transformers. For example, after conducting a detailed technical assessment, ElectraNet has now applied 30 minute ratings to the South East 275/132 kV transformers when power is flowing from the 132 kV to the 275 kV networks (i.e. under favourable operating conditions). This has released additional transmission capacity and reduced the occurrence of network and interconnector constraints.

ElectraNet has also previously implemented real-time rating of transmission lines where it was demonstrably beneficial to do so. In another new development, ElectraNet has implemented a tension monitoring system on both the Robertstown to North West

Bend #1 line and the first section of the Robertstown to North West Bend #2 line. Under favourable environmental conditions, this will achieve higher line ratings compared to what would otherwise have been the case. This outcome will support both the load in the Riverland and increase the capability of the lines to support exports on Murraylink interconnector.

ElectraNet will continue to review the impact of network thermal constraints and consider all available options to alleviate them. Such constraints will be considered on a case-by-case basis and action taken to mitigate them if it can be shown to be technically feasible and economic to do so.

5.6 Planned and Recently Commenced Strategic Studies

5.6.1 System Integration of Heywood Interconnector Upgrade

5.6.1.1 South East Under-Frequency Tripping Scheme

Due to the changes that will be made to the interconnected transmission system as a result of the Heywood Interconnector Upgrade project, ElectraNet conducted system studies to re-assess the requirement for the existing South East under frequency sever scheme.

System studies were conducted for various system operating conditions including SA import and export transfers up to 650 MW with existing protection tripping schemes, including the Victorian Alcoa Portland Potline Emergency Tripping scheme.

The outcome of this study is a recommendation that ElectraNet:

- Disable the South Australian under-frequency severing scheme to enable more rapid restoration of an islanded South Australian system to the interconnected NEM following a separation event; and
- Further investigate the costs associated with including inverse time characteristic protection on capacitor banks to assist in managing system voltages during significant load shedding events.

These recommendations have been endorsed by AEMO following the completion of a due diligence assessment.

5.6.1.2 Review of System Damping for Heywood Interconnector Upgrade

It is expected that the Heywood Interconnector Upgrade project will be able to support import and export transfers of up to 650 MW. ElectraNet has completed a limited South Australian system damping assessment of the impact of the Heywood Interconnector upgrade project on system oscillatory limits.

The study considered:

- Typical system normal operating conditions with total South Australian import/export at 870 MW (650 MW limit for the Heywood interconnector and 220 MW for Murraylink);
- A range of South Australian-Victorian transfer levels up to 870 MW in each direction; and

- Various South Australian system demand levels with minimum conventional/wind generation dispatch scenarios.

The study confirmed that the South Australian system has sufficient damping after completion of the Heywood Interconnector upgrade, even with no power system stabilisers in service.

Note that the study was limited to assessing the damping behaviour of the South Australian network only. Operating conditions in other parts of the NEM and transfer limits across other inter-connectors in the NEM were held constant over the range of scenarios considered.

AEMO will conduct a further study to assess the impact on NEM-wide interconnected network system damping.

5.6.2 Managing Low System Demand and High 275 kV System Voltage Periods

Low-demand periods are becoming more frequent and the level of minimum demand has been rapidly diminishing, largely due to:

- The increasing penetration of distributed solar PV, and
- Increases in consumers' energy efficiency.

The result of these changes is forecast to yield an increased occurrence of operating conditions that are characterised by high voltage levels, particularly on the SA 275 kV Main Grid. This is may cause the Para SVCs to operate at a set-point deep in their inductive range, potentially reducing the ability of the SVCs to stabilise the system following a significant system disturbance.

In addition, the Para SVCs have at times in recent years operated increasingly deeply into their inductive range in the early hours of the morning. This has occurred as the Para SVC operates to limit the voltage level rise on the 275 kV Main Grid after the rapid drop-off in system demand that has been observed to follow the midnight pumping and water heating peak.

ElectraNet has commenced a study into the best means of addressing the types of system conditions described above to ensure system security is maintained. The study will include consideration of:

- The ability of the lines and plant that comprise the SA 275 kV Main Grid to withstand sustained high voltages;
- The ability of the system to remain stable following a significant system disturbance during times of low demand and high system voltage levels;
- A range of solutions that may be able to address specific limitations identified, which may include options such as:
  - changes to operational procedures;
  - non-network solutions such as demand shifting or control of embedded generation; and
  - network solutions such as the installation of switched 275 kV reactors.

An update on the progress of this study is planned for inclusion in the 2016 Transmission Annual Planning Report.

5.6.3 Involvement in ARENA-Funded ESCRI-SA Study

During 2014, ElectraNet joined with AGL and Worley Parsons to develop an application to the Australian Renewable Energy Agency (ARENA) for the funding of a project examining and then potentially trialling a medium scale energy storage project in South Australia.

This has since progressed, and the Energy Storage for Commercial Renewable Integration – South Australia (ESCRI-SA) project was established to examine the role of medium to large scale (5-30 MW) non-hydro energy storage in the integration of intermittent renewable energy into South Australia.

In the first phase of the ESCRI-SA project a key objective is the development of a business case for the trial of a full scale grid-connected energy storage system (comprising Energy Storage Devices, ESDs) in South Australia.

ESDs may potentially act as a consumer of electricity, a producer of electricity, a provider of system ancillary services, and/or a provider of network support services.

This is the first time in Australia that the commercial viability of an energy storage device that combines all of these potential roles is being evaluated.

The development of the business case for a potential ESD in South Australia includes the following key tasks:

- A review of the regulatory environment as it applies, or could apply, to energy storage device;
- Identification of a potential site or sites in South Australia where an ESD would be able to access multiple value streams;
- A state-of-the-art technology review of ESDs, leading to storage technology selection; and
- Development of a potential commercial framework.

Knowledge sharing, which is a key part of this study will occur later in 2015.

6. Connection Opportunities

About this chapter

This chapter is intended to provide high level information to prospective customers regarding the capability of the network to accommodate new generator and load connections.

This information formed chapter 5 in the 2014 Transmission Annual Planning Report.

This year, the information presented in section 6.1 has been added to include the results of an indicative study into the amount of additional generation that could be accommodated at key transmission network locations, without resulting in significant network constraints or requiring significant network augmentation.

6.1 Generation Connection Opportunities

Whilst the NEM currently has an oversupply of generation that is likely to continue for some time, almost any point in proximity of the Main Grid 275 kV transmission system should be suitable for a new generator to connect.

In particular, several 275 kV substations in the Mid North represent strategic locations in close proximity to fuel resources including wind. The sites that are electrically favourable for connecting generation are located along the 275 kV backbone from Port Augusta (near Davenport and Cultana) to South East (near Penola and Krongart).

In the Metropolitan region, population density limits the ability to economically provide new infrastructure to extend the network. Existing fault levels are approaching the plant capability limits of both ElectraNet's and SA Power Networks' assets, particularly in the vicinity of Torrens Island, Le Fevre, Kilburn, Northfield, Magill and within the Adelaide Central Region. Therefore, while the existing Metropolitan 275/66 kV system may be able to accommodate new generation connections, these may accelerate the need for major augmentation and/or replacement of existing network assets at a number of locations to address fault level issues.

South Australia has abundant renewable energy resources. Key considerations that may impact the future ability of ElectraNet's transmission network to accommodate significant amounts of new renewable generation include:

- The Heywood Interconnector upgrade is currently underway. This has been considered in the calculation of indicative generator connection capability. Additional incremental upgrades along key transmission corridors, including across the Heywood interconnector corridor, would further alleviate forecast thermal constraints and hence assist further deployment of generation in South Australia;
- Opportunities to minimise intra-regional transmission constraints by implementing projects that deliver net positive market benefits are assessed by ElectraNet on an ongoing basis. These projects will tend to increase the amount of generation that could be connected to the South Australian transmission system; and

- The changing dispatch behaviour of existing conventional generation also has the potential to change the pattern of power flows on the transmission system, which may alter the capacity of the South Australian transmission network to accommodate increased generation.

ElectraNet has assessed at a high level the ability of existing transmission network nodes and connection points to accommodate the connection of new generators. The ability of ElectraNet's transmission network to accommodate new generation has been examined across a range of demand, generation, and interconnector operating conditions. The study determined the indicative maximum generation capacity that can be connected without breaching line and transformer thermal ratings under system normal and single credible contingency conditions.

To prepare for the study:

- The planned system configuration for summer 2016-17 was used, to include a transfer capacity of 650 MW across the Heywood interconnector;
- Seven conditions were developed to represent different operating conditions of the transmission system under different levels of demand and generation, as shown in Table 6-1; and
- Buses were selected for assessment that:
  - are at representative locations across the network;
  - are outside of the Metropolitan region; and
  - do not supply direct-connect customers.

Table 6-1: Network conditions examined for assessment of ability to connect new generation

Network Condition	Demand (MW)	Wind	Conventional Generation	Heywood transfer (MW)	Murraylink transfer (MW)
Maximum Load-Zero transfer	3200	40%	29 units	0	0
Maximum Load-Max import	3200	9%	27 units	547 import	0
Medium Load-Zero transfer	1400	40%	4 units	0	28 import
Medium Load-Max import	1400	9%	4 units	547 import	28 import
Medium Load-Max export	1400	90%	4 units	650 export	28 import
Light Load-Zero transfer	800	1%	4 units	0	22 export
Light Load-Max export	800	75%	2 units	650 export	22 export

For each study condition, seasonal thermal ratings were applied to lines, and AEMO's operating margins were taken into account for line ratings in the South East and Riverland regions and on the Tailem Bend to Mobilong 132 kV line.

For the selected 132 kV and 275 kV connection locations, simulations representing system normal and single credible contingency conditions were performed for the connection of a notional generator. The output of the notional generator was gradually increased while the dispatch of other in-service conventional and wind generators was uniformly decreased to maintain supply-demand balance. At each location and for each system condition, simulations were stopped when a thermal overload was observed on a line or transformer.

The indicative additional connectable generation at each location was then deemed to be the minimum value that was observed across the studied network conditions.

For 33 kV and 66 kV connection point buses, a spreadsheet assessment was made of the secure transformer capacity available to connect new generation at light demand times. This was compared to the generation that was deemed connectable at the local high voltage bus, and the lower of the two values was adopted for the lower voltage bus.

The assumed transfer level across the Murraylink interconnector had a significant impact on the indicative additional generation that can be connected in the Riverland and on the 132 kV network in the Mid North. The assumed Murraylink interconnector transfer was manually adjusted to determine the amount of connectable generation at Berri and Monash.

High-level indicative results of the ability of ElectraNet's transmission network and connection points to accommodate new generation (in addition to any existing generation) are shown in Table 6-2. The results shown include the impact of committed projects.

Table 6-2: High-level indicative new generator connection capability in 2016-17

Indicative Additional Connectable Generation (MW)	Locations
0- 49	Angas Creek (33 kV), Ardrossan West (132 kV and 33 kV), Baroota (132 kV and 33 kV), Blanche (132 kV and 33 kV), Brinkworth (275 kV, 132 kV and 33 kV), Clare North (132 kV and 33 kV), Dalrymple (132 kV and 33 kV), Hummocks (132 kV and 33 kV), Kadina East (132 kV and 33 kV), Kanmantoo (33 kV), Keith (132 kV and 33 kV), Kincraig (132 kV and 33 kV), Leigh Creek South (132 kV and 33 kV), Mannum (33 kV), Middleback (132 kV), Mount Gambier (132 kV and 33 kV), Mount Gunson (33 kV), Neuroodla (132 kV and 33 kV), North West Bend (132 kV and 33 kV), Penola West (132 kV and 33 kV), Port Lincoln Terminal (132 kV and 33 kV), Robertstown (132 kV), Snuggery (132 kV and 33 kV), South East (275 kV and 132 kV), Tailem Bend (275 kV, 132 kV and 33 kV), Templers (132 kV and 33 kV), Templers West (275 kV), Waterloo (132 kV and 33 kV), Wudinna (132 kV and 66 kV), Yadnarie (132 kV and 66 kV)
50 - 99	Davenport (33 kV), Dorrien (132 kV and 33 kV), Kanmantoo (132 kV). Mobilong (33 kV), Monash (66 kV), Port Pirie (132 kV), Whyalla LMF (33 kV)
100 - 149	Berri (132 kV and 66 kV), Bungama (132 kV), Mobilong (132 kV), Monash (132 kV), Mount Gunson (132 kV), Pimba (132 kV)
150 - 199	Angas Creek (132 kV), Davenport (132 kV), Mannum (132 kV), Whyalla Central (33 kV)
≥ 200	Belalie (275 kV), Blyth (275 kV), Bungama (275 kV), Canowie (275 kV), Cultana (275 kV and 132 kV), Davenport (275 kV), Mokota (275 kV), Mount Barker (132 kV), Robertstown (275 kV), Tungkillo (275 kV), Whyalla Central (132 kV)

6.2 Load Connection Opportunities

Almost any point in the proximity of the Main Grid 275 kV transmission system should be suitable for a new large load to connect. However, any substantial load connections may require deep network augmentation to supply demand and to provide a reliable supply arrangement.

Metropolitan electricity demand has grown steadily until recent years as a result of residential, commercial and industrial development in the Adelaide metropolitan area. SA Power Networks’ distribution network supplies individual electricity consumers. The existing Metropolitan 275/66 kV network can accommodate new load connections. Depending on their size and location, these load connections may accelerate the need for the major augmentation and/or replacement of existing assets.

For other regions, ElectraNet has assessed the ability of existing connection points to accommodate the connection of new large loads. This has been done through the application of Power-Voltage (P-V) analysis, which determines the relationship between network voltage levels and the power drawn at a node (or nodes), for a range of relevant system conditions (including system normal and credible single contingencies).

The maximum amount of increased demand at a given connection point that could be accommodated has been determined by comparing network voltage levels to the relevant voltage criteria, for example:

- 275 kV and 132 kV voltage levels to remain above 95% of nominal during system normal conditions;
- 275 kV and 132 kV voltage levels to remain above 90% of nominal after a single credible contingency event; and
- The total load at the connection point must remain at least 5% below the level at which voltage collapse occurs (identified as the "knee point" on the relevant P-V curve).

This year, the thermal capacity of the transmission network has also been applied as a limit to the amount of additional demand that could be supplied at each connection point. This was not the case for all of the corresponding figures presented in ElectraNet's 2014 Transmission Annual Planning Report.

The ability of potential low-cost projects to release additional thermal transmission network capacity (for example, by replacing low-cost plant that may limit the available rating of a transmission line) has not been considered: hence, in some cases it may be feasible to connect larger loads following a targeted small expenditure to increase the available capacity of upstream assets.

The results of a P-V study for the summer of 2016-17 are shown in Table 6-3. The values listed represent the additional load that could be connected to the connection point's high voltage bus, in addition to the forecast 2016-17 10% POE load.

It is important to note the following limitations of the study results presented in Table 6-3.

- It has been assumed that any additional load at each existing connection point will be subject to the same ETC reliability requirements as the connection point. If a less-onerous reliability requirement is appropriate for any new load that is connected, it may allow for an increase to the maximum load that can be accommodated;
- An increase in the load connected at one connection point would reduce the additional load that could be accommodated at other connection points, particularly for connection points in close electrical proximity;
- The loads provided represent the capability of the existing transmission *network* only, and do not account for any additional transformer capacity that may be required to facilitate connection at voltage levels below 275 kV or 132 kV (as applicable); and
- The table only considers the additional load that could be connected at existing connection points. Other network locations that do not yet supply connection point loads (e.g. Cultana 275/132 kV and South East 275/132 kV substations) have not been considered.

Table 6-3: Results of P-V analysis for summer 2016-17

Connection Point	HV Voltage Level (kV)	Additional load that could be connected in 2016-17 (MW)
Eastern Hills		
Angas Creek	132	75
Kanmantoo	132	60
Mannum	132	80
Mobilong	132	90
Mt Barker	132	85
Mt Barker South	275	>200
Eyre Peninsula		
Port Lincoln Terminal	132	15
Stony Point	132	40
Whyalla Central	132	45
Whyalla LMF	132	45
Wudinna	132	20
Yadnarie	132	25
Mid North		
Ardrossan West	132	15
Baroota	132	25
Brinkworth	132	40
Clare North	132	40
Dalrymple	132	15
Dorrien	132	80
Hummocks	132	20

Connection Point	HV Voltage Level (kV)	Additional load that could be connected in 2016-17 (MW)
Kadina East	132	15
Templers	132	60
Waterloo	132	30
Riverland		
Berri	132	5
North West Bend	132	5
South East		
Blanche	132	50
Keith	132	135
Kincraig	132	70
Mt Gambier	132	45
Penola West	132	50
Snuggery	132	100
Tailem Bend	132	155
Upper North		
Davenport West	132	125
Leigh Creek South	132	25
Mt Gunson	132	65
Neuroodla	132	30

6.3 Current and Possible Future Transmission Network Nodes

ElectraNet endeavours to develop connections for new generators and loads to provide a cost effective, but low long term constraint risk solution to the customer. Where a number of generators and/or loads are developed in close proximity, it is important to provide efficient connections wherever possible. This approach is intended to minimise network constraints for the customer, maximise network utilisation, reduce connection costs, and facilitate efficient and sustainable long-term development of the transmission network.

For example, wind farm developments in the Mid North are connected to ensure that loading on the parallel 275 kV lines between Port Augusta and Adelaide is as balanced as possible, to reduce the likelihood of generation constraints and limitations to power transfer capability in the corridors as the power transfer requirements increase in the future.

Generators and load customers should note that in response to a connection enquiry, ElectraNet will consider the location and configuration of the connection to efficiently utilise the existing shared network in the long term. ElectraNet may recommend connection to a specific network location if it is efficient to do so. ElectraNet will also specify the appropriate configuration for that connection.

Nodal connection points allow for tying together parallel transmission lines and efficient placement of new generation in the system, to further balance line loadings and thereby maximise thermal transfer capability on the existing network.

Figure 6-1 shows the placement of current and possible future network nodes in the South Australian transmission network.

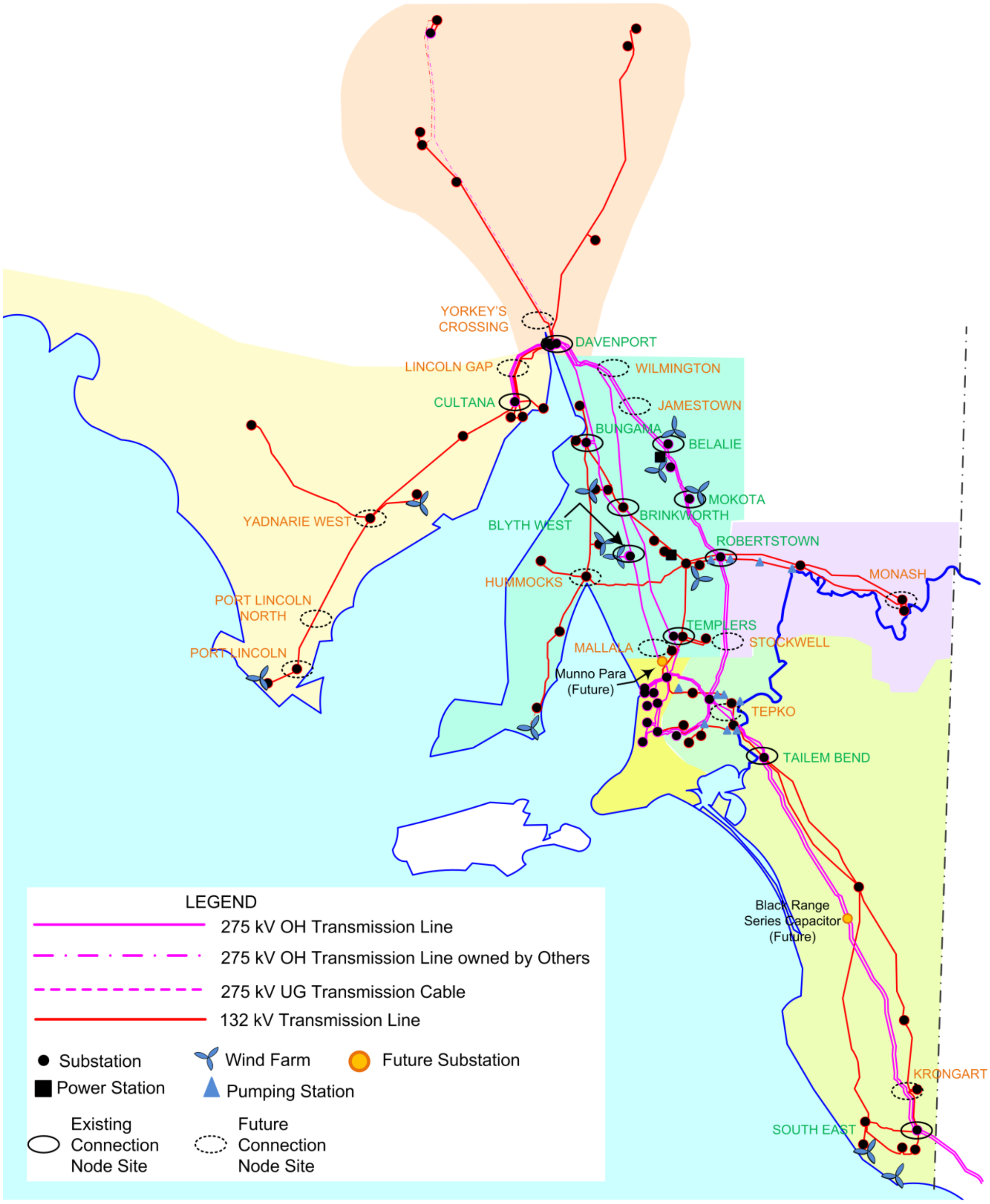


Figure 6-1: Current and possible future network nodes

7. Transmission Network Developments

About this chapter

Section 7.1 provides a brief summary of how transmission network development plans have changed as a consequence of this year's updates to the connection point demand forecasts.

Section 7.2 describes augmentation, connection and replacement projects that have been completed during 2014-15, or are in progress. This section corresponds to chapter 6 of ElectraNet's 2014 Transmission Annual Planning Report. There are no significant changes to the content compared to that in the 2014 edition.

Sections 7.3 onwards provide information about potential future development of the South Australian transmission network. These developments include projects to meet various needs, such as to:

- Augment capacity to meet increasing connection point demand;
- Maintain compliance with Rules obligations;
- Improve system security and operational flexibility;
- Maintain adequate asset condition; or
- Provide net market benefits by minimising transmission network constraints.

Section 7.3 onwards corresponds to chapter 7 of ElectraNet's 2014 Transmission Annual Planning Report.

Changes to the information contained in these sections compared to chapter 7 of ElectraNet's 2014 Transmission Annual Planning Report include the presentation of three planning scenarios, compared to the single scenario that was presented in 2014. The planning scenarios have been selected to represent an extreme, yet potentially credible, range of assumptions regarding future developments.

A note on costs

Estimated project costs quoted in this chapter are presented in 2014-15 dollar values. Cost estimates are provided as a range to better reflect the variability of expected project costs. The estimated range for proposed projects is typically wider than for committed and pending projects, due to uncertainties about project scope, contingencies and risk in the early stages of a project.

7.1 Changes to Augmentation Plans Compared to the 2014 Transmission Annual Planning Report

The augmentation plans presented in this Transmission Annual Planning Report are based on the connection point demand forecast that was provided by SA Power Networks in September 2014. Details of the forecast can be found in the 2015 South Australian Connection Point Forecasts Report[28], published by ElectraNet in February 2015. It represents a significant drop in the future demand forecast at most connection points compared to the demand forecast provided by SA Power Networks in June 2013, which was the basis for the augmentation plans presented in the 2014 Transmission Annual Planning Report. As a result, there are significantly fewer proposed transmission network development projects presented in this current Transmission Annual Planning Report compared to the 2014 edition.

7.2 Completed, Committed and Pending Projects

7.2.1 Recently Completed Projects

Over the past year, ElectraNet has completed several projects to remove network limitations and address asset condition. Table 7-1 lists projects completed since publication of the 2014 Transmission Annual Planning Report.

Table 7-1: Projects completed between 1 June 2014 and 30 April 2015

Project Description	Region	Project Category	Asset in Service
Magill - Happy Valley 275 kV Line Insulator Replacement Replaced porcelain disc insulator assemblies that had reached end of life on the Magill to Happy Valley 275 kV transmission line	Metropolitan	Refurbishment	5/12/2014
Torrens Island 66 kV Unit Asset Replacements Replaced selected primary plant in situ, all secondary systems, two control rooms and associated equipment at TIPS 66 kV substation, as a result of detailed condition assessment and asset replacement risk analysis. Plant replacements also enabled the substation to handle increased fault levels. Work on the TIPS 66 kV substation will continue with unit asset replacements required in the 2013-2018 period (refer to project in Table 7-2**)**	Metropolitan	Replacement	12/01/2015

7.2.2 Committed Projects

Committed projects are projects that have completed the RIT-T (where required), and are fully approved by the ElectraNet Board. Table 7-2 lists committed projects, which ElectraNet is currently undertaking and are expected to be completed in the near future.

[28] Available at http://www.electranet.com.au/network/transmission-planning/south-australian-connection-point-forecasts-report/

Table 7-2: Committed projects

Project Description	Region	Project Category	Expected Service Date
Munno Para New 275/66 kV Connection Point ElectraNet and SA Power Networks' joint planning and Regulatory Test found that a new 275/66 kV connection point at Munno Para will provide the most economical solution to limitations on the SA Power Networks distribution network. The project will build a new 275/66 kV 225 MVA connection point substation at Munno Para, connecting into the Para to Bungama 275 kV line, and install neutral earthing reactors on the Para and Parafield Gardens West transformers	Metropolitan	Augmentation	02/06/2015
Mt Gunson 132/33 kV Connection Point Replacement Replace selected end-of-life plant at Mt Gunson substation with modern-day equipment and install a 10 MVA 132/33 kV transformer	Upper North	Replacement	29/06/2015
Robertstown – North West Bend #1 and #2 132 kV Lines Dynamic Line Ratings Install and commission dynamic line rating on the Robertstown - North West Bend #1 and #2 132 kV lines, to increase available Murraylink transfers from South Australia into Victoria, particularly during extreme summer temperature events	Riverland	Augmentation	30/06/2015
Brinkworth – Mintaro 132 kV Line Remediation and Insulator Replacement Replace porcelain disc insulator assemblies that have reached end of life, as well as defective poles and cross arms, on the Brinkworth to Mintaro 132 kV transmission line, to extend the life of the transmission line by at least 15 years	Mid North	Refurbishment	14/07/2015
Neuroodla 132/33 kV Connection Point Replacement Rebuild Neuroodla substation within the existing substation site, installing a 10 MVA 132/33 kV transformer and modern-day equipment	Upper North	Replacement	17/07/2015

Project Description	Region	Project Category	Expected Service Date
South East Additional 275 kV Circuit Breakers Substandard circuit breaker arrangement at South East substation, which constrains the Heywood Interconnector and places network security and reliability at risk, will be addressed by installing additional circuit breakers and associated switchgear, metering and protection at South East substation	Main Grid	Security and compliance	17/12/2015
Para Unit Asset Replacements Replace the 275 kV, 132 kV and 66 kV secondary system, associated telecommunications systems, control buildings and selected primary plant at Para substation as a result of detailed condition assessment and asset replacement risk analysis. The project scope and schedule have been extended to include unit asset replacements required in the 2013-2018 period	Metropolitan	Replacement	11/04/2016
Heywood Interconnector Upgrade Incremental augmentation of the Heywood interconnector, to raise nominal transfer limits from ±460 MW to ±650 MW, has been shown to deliver market benefits using the RIT-T. The approved solution is to install a third 500/275 kV transformer at Heywood terminal station, series compensation[29] on the South East to Tailem Bend 275 kV lines and reconfigure the existing 132 kV transmission system between Snuggery, Keith and Tailem Bend	Main Grid/ South East	Augmentation	05/07/2016[30]
Various Unit Asset Replacements Program to replace individual unit assets, such as circuit breakers, voltage transformers, current transformers or protection relay sets that have reached end of life, at 36 substations	Various	Replacement	30/10/2017

The following sections provide additional detail for major (expenditure greater than $5 Million at a single site) committed augmentation projects.

[29] Series compensation reduces the "electrical distance" of a transmission line, thereby increasing the maximum possible power transfer over the line.
[30] Following installation of the series compensation by this date, testing will be undertaken and be followed by the gradual release of additional interconnector capacity by AEMO.

7.2.2.1 Munno Para 275 kV Injection

Scope of Work:	Establish a new 275/66 kV injection point at Munno Para comprising a single 225 MVA transformer, connecting into the Para to Bungama 275 kV line, and install neutral earthing reactors on the Para and Parafield Gardens West transformers
Estimated Cost:	$30-35 Million (ElectraNet costs only)
Timing:	June 2015
Project Status:	Construction in progress

Project Need:

This project is driven primarily by a SA Power Networks connection request. SA Power Networks has indicated that load growth in the Northern Suburbs sub-region causes constraints in the underlying 66 kV sub-transmission system. This load growth is also forecast to cause 275/66 kV transformer capacity constraints that this project will resolve.

Public consultation on this project was completed in October 2007, under the pre-August 2010 Regulatory Test for Reliability Augmentations. Since the Regulatory Test, changes to demand forecasts and joint planning with SA Power Networks have enabled the project requirement to be deferred from 2014 to 2015.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

7.2.2.2 Heywood Interconnector Upgrade

Scope of Work:	Install series compensation on the South East – Tailem Bend 275 kV lines and increase the transfer capacity of the South East to Tailem Bend corridor
Estimated Cost:	$40-50 Million (SA component)
Timing:	July 2016
Project Status:	Committed, detailed design and construction contracting in progress

Project Need:

The Heywood interconnector is located between the South East (South Australia) and Heywood (Victoria) substations. Historically this interconnector has predominantly been used to import power into South Australia. However over the past few years, with the addition of significant amounts of wind generation in South Australia, the interconnector is also being used to export power from South Australia.

The ‘identified need’ for the investment is an increase in the sum of producer and consumer surplus, i.e., an increase in net market benefit.

Two main limitations currently affecting the Heywood interconnector have been identified. The first involves thermal capabilities and voltage stability limitations in south-east South Australia. The second is the transformer capacity at Heywood. Alleviating both these limitations would increase the import and export capability of the interconnection. ElectraNet and AEMO consider that increasing the capability of the interconnection will achieve an overall increase in net market benefit in the NEM. This has been demonstrated in the analysis presented in the Project Assessment Conclusions Report (PACR) that was published jointly by AEMO and ElectraNet in January 2013.

In August 2013, the AER determined that the preferred option in the PACR, as described in the project scope below, satisfies the RIT-T, as per section 5.16.6 of the Rules. The AER made its contingent project decision in March 2014 and approved the incremental revenue for the project requested by ElectraNet.

The project scope includes:

- A third 500/275 kV transformer at the Heywood 500 kV terminal station, to be delivered by AEMO and AusNet Services (scheduled commissioning date 30 September 2015);
- Series compensation of the two South East to Tailem Bend 275 kV lines;
- Reconfiguration of substation assets and the existing 132 kV transmission system to allow increased utilisation of transmission line thermal ratings along the 275 kV interconnector;
- South East 275/132 kV transformer control scheme, subject to the voluntary participation of the relevant generator(s); and
- A protection and control scheme that will bypass the series capacitors if either sub-synchronous oscillations or a network condition that could lead to the growth of sub-synchronous oscillations is detected.

A review of the South Australian limit equations with the third Heywood 500/275 kV transformer in service is currently underway and is expected to be completed by June 2015, three months ahead of the scheduled transformer commissioning date.

In developing the network augmentation components, due consideration has been given to alleviating most of the existing intra-regional network limitations in south-east South Australia.

This upgrade is expected to have a material impact on inter-regional transfer as it will increase interconnector capability by about 40% in both directions. The net market benefits are estimated at more than $190 Million (in present value terms) over the life of the project with positive net benefits commencing from the first year of operation.

Inter-regional testing requirements will be performed in stages as part of the commissioning tests for the series compensation installation. Following each test, the increased transfer capability will be released in steps above the existing 460 MW after formal endorsement by the Plant Modelling Working Group. The full 650 MW capacity is expected to be released in the second half of 2016.

Figure 7-1 shows the approved project scope.

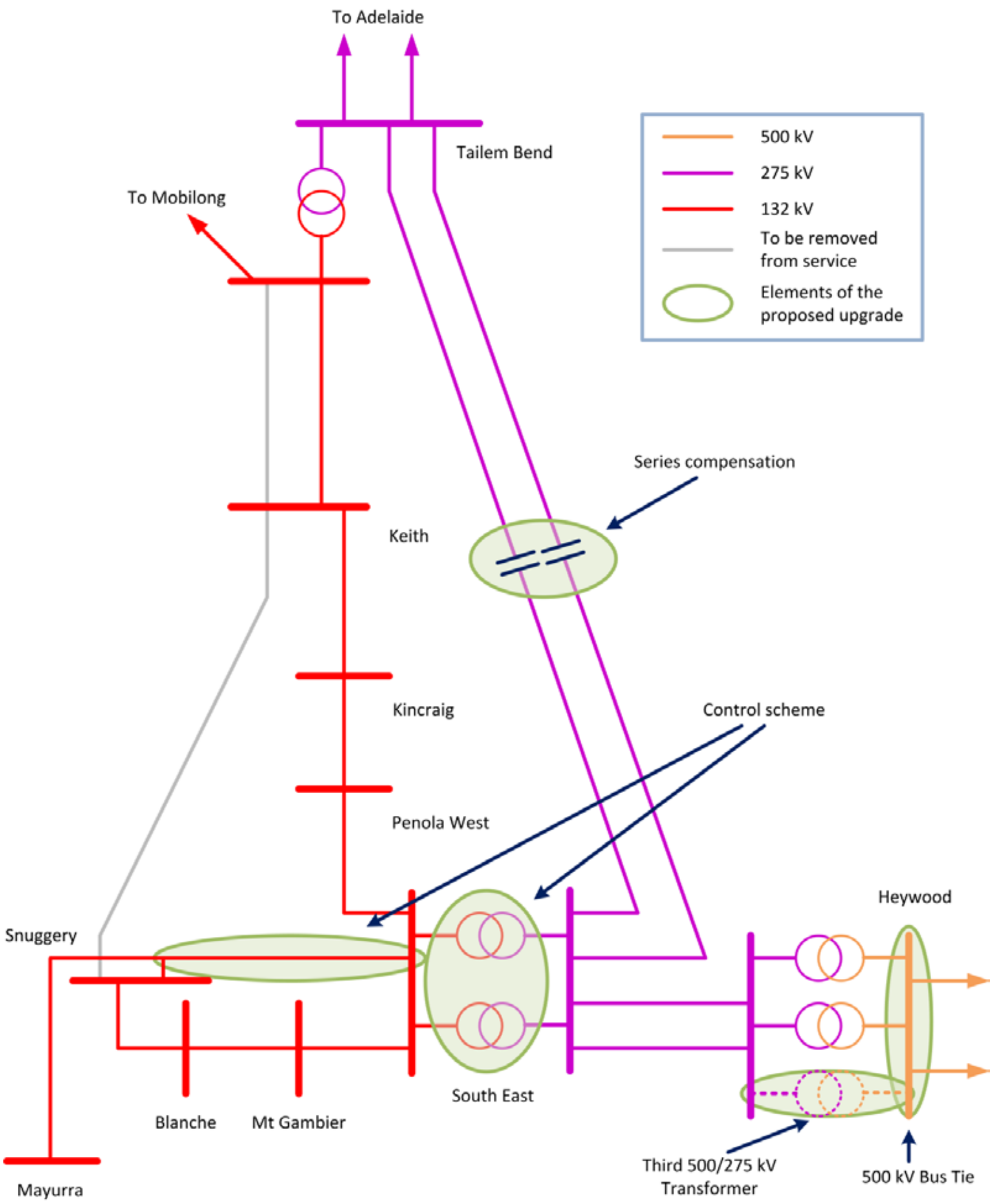


Figure 7-1: Components of Heywood Interconnector Upgrade project scope

7.2.3 Pending Projects

The following project is currently pending, meaning that the project has passed the RIT-T but is not yet fully committed.

7.2.3.1 Install a Second 25 MVA 132/33 kV Transformer at Dalrymple Substation

Scope of Work: Install an additional 25 MVA 132/33 kV transformer at Dalrymple

Estimated Cost: $14-16 Million ($10-12 Million ElectraNet costs)

Timing: November 2016

Project Status: Pending (RIT-T completed)

Project Need:

From 1 December 2016, the ETC assigns Dalrymple connection point to reliability category 2, meaning that the equivalent transformer capacity at Dalrymple must be adequate to supply the Agreed Maximum Demand (AMD) with one transformer out of service. With only one transformer currently installed at Dalrymple, and no currently-available network support arrangement, the existing connection point will not meet the required level of reliability from 1 December 2016.

As the most expensive credible option to overcome this constraint exceeds $5 Million, ElectraNet carried out public consultation in accordance with the RIT-T process. A Project Assessment Conclusions Report was published in November 2013. No submissions were received during the RIT-T public consultation periods.

However, ElectraNet subsequently reviewed the economic case for the Dalrymple upgrade, which showed a lower market benefit than the original analysis. Given this reduction in market benefit, ElectraNet has significantly changed the scope and cost of the preferred option arising from the RIT-T by reducing reliability and operability as well as removing flexibility for future expansion of the site. The revised economic analysis has confirmed that the reduced scope preferred option does produce a net market benefit.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

7.3 Transmission Network Development Planning

The Rules require ElectraNet and SA Power Networks to analyse the expected future operation of the South Australian network, taking into account forecast loads, future generation, market network services, demand side participation and transmission developments.

The outcome of the analysis is presented in this Transmission Annual Planning Report for the South Australian transmission network. The objective of the development plan is to address projected limitations on the South Australian transmission network over a 10-year period.

This development plan has been prepared according to the planning framework described in section 1.4.1.

The demand forecast for this transmission network development plan is summarised in chapter 4, with detailed forecasts provided in the 2015 South Australian Connection Point Forecasts Report. Diversity factors have been applied as appropriate in each case for planning the Main Grid and regional corridors. Main Grid and regional meshed networks are planned to meet 10% POE demands with wind farm outputs set to 8.6% of their installed capacities, which reflects the 85% confidence interval for South Australian wind farm output during the top 10% of summer demand periods (refer to section 2.2). Based on the 2014 NTNDP least cost generation expansion plan, there will be no new conventional generation plant built in South Australia within the planning horizon.

Substation fault levels are assessed to ensure they will remain within design and equipment limits. The connection point fault level calculation results are presented in Appendix D.

This remainder of this chapter follows the following format:

- Section 7.4 describes the assumptions regarding transmission network development drivers that underpin each of the three planning scenarios that have been considered as part of this transmission network development plan;
- Section 7.5 provides a high-level comparison of the planning outcomes for each of the three planning scenarios. Sections 7.6 through to 7.8 then deal with the outcomes of the analysis for each planning scenario in turn, briefly describing the proposed network reinforcement projects (committed and pending projects are covered in sections 7.2.2 and 7.2.3 respectively) within the next ten years; and
- Section 7.9 contains summary reference tables of network augmentation, security and compliance as well as replacement projects. These tables also include committed and pending projects covered in sections 7.2.2 and 7.2.3 respectively.

7.4 Planning Scenario Definitions

Three planning scenarios, representing differing assumptions regarding the future development of demand and generation in South Australia, have been developed and evaluated as part of ElectraNet's planning process. The three scenarios are intended to represent a range of extreme, but credible, potential futures.

The three planning scenarios are:

- The Base scenario;
- The SA Mining Growth scenario; and
- The SA Renewable Generation Expansion scenario.

Table 7-3 describes the characteristics of each planning scenario and the assumptions that have been made in each case.

Figure 7-2 is a graphical representation of the potential new mining loads that have been considered over the next ten to twenty years as part of the SA Mining Growth scenario.

Figure 7-3 is a graphical representation of the potential new wind farms that have been considered over the next ten years as part of the SA Renewable Generation Expansion scenario.

Table 7-3: Planning Scenario Assumptions

Characteristic	Base	SA Mining Growth	SA Renewable Generation Expansion
Purpose of Scenario	This is ElectraNet's central planning scenario	This scenario considers a number of potential future mining loads. These are based on received connection enquiries, which have been generalised for long-term planning	This scenario represents an extreme yet possible future expansion of SA wind generation. It is based on received connection enquiries, which have been generalised for long-term planning
Connection Point maximum demand forecasts	SA Power Networks' September 2014 connection point 10% POE medium forecast SA light load scenario projected from observed minimum demand on 21 September 2014	SA Power Networks' September 2014 connection point 10% POE medium forecast, adjusted upwards by 10% in 2023-24 and by 20% in 2033/34	SA Power Networks' September 2014 connection point 10% POE medium forecast, adjusted downwards by 10% in 2023-24 and by 20% in 2033-34
SA transmission system coincident maximum demand forecast	AEMO's 2014 NEFR 10% POE forecast	AEMO's 2014 NEFR 10% POE forecast, adjusted upwards by 10% in 2023-24 and by 20% in 2033-34, plus the assumed direct-connect customer demand increases	AEMO's 2014 NEFR 10% POE forecast, adjusted downwards by 10% in 2023-24 and by 20% in 2033-34
Direct-connect customer demand increases	No new increases	As shown in Figure 7-2	No new increases
New or retired conventional generation plant	Maintain existing conventional generation fleet	Expand thermal generation fleet to the minimum extent required to meet additional demand. New entrants determined by a desktop study of conventional generation technologies most suitable to meeting new mining loads with consideration of the state's energy and capacity needs as well as the capability of the interconnectors	Maintain existing conventional generation fleet
New wind farm connections	No new wind farm connections within the next 10 years	No new wind farm connections	As shown in Figure 7-3
Generation dispatch	Assumptions guided by 2014 ESOO and GSOO		
Embedded solar PV	Based on SA Power Networks' medium embedded solar PV forecast at connection points		

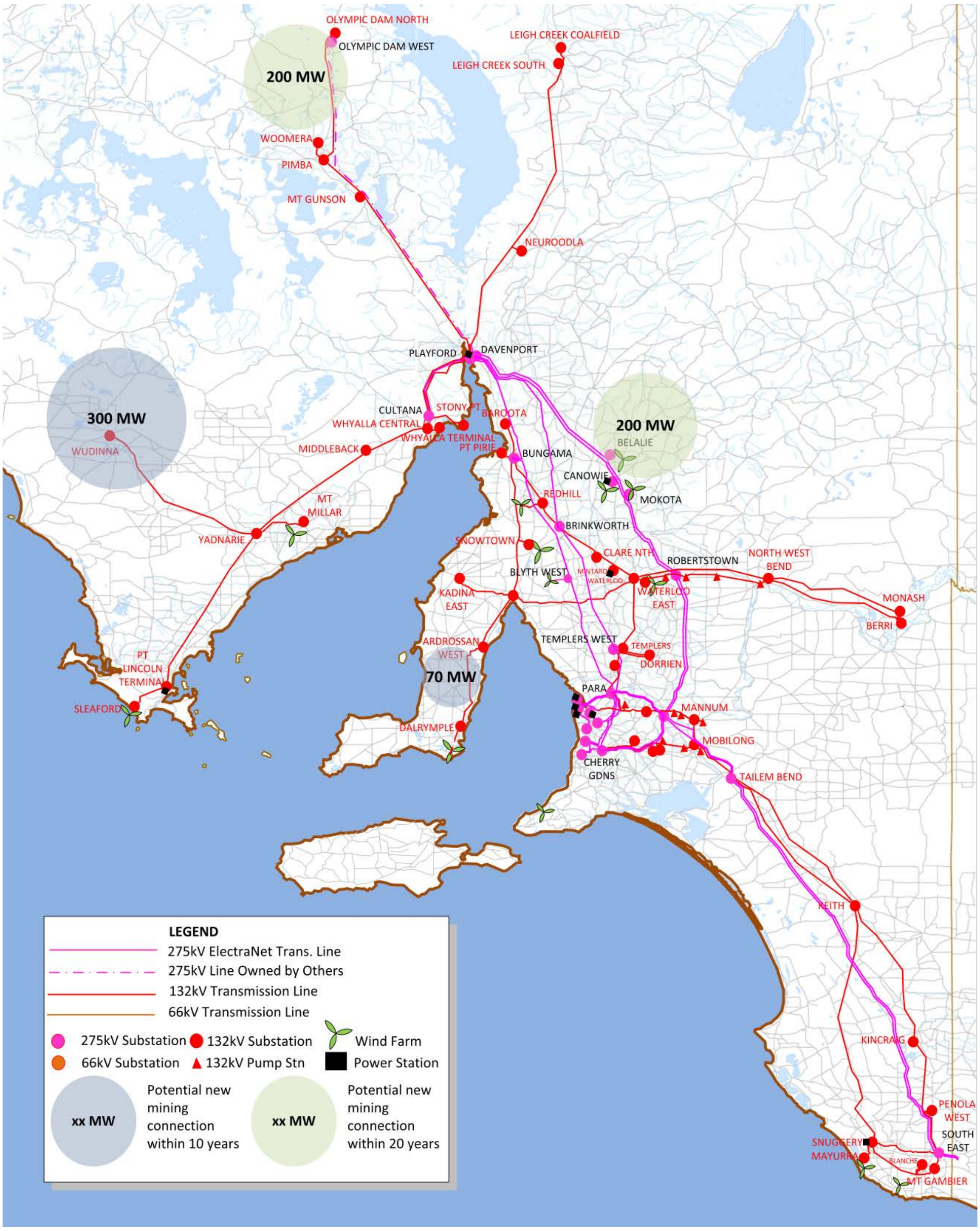


Figure 7-2: Potential future mining connections

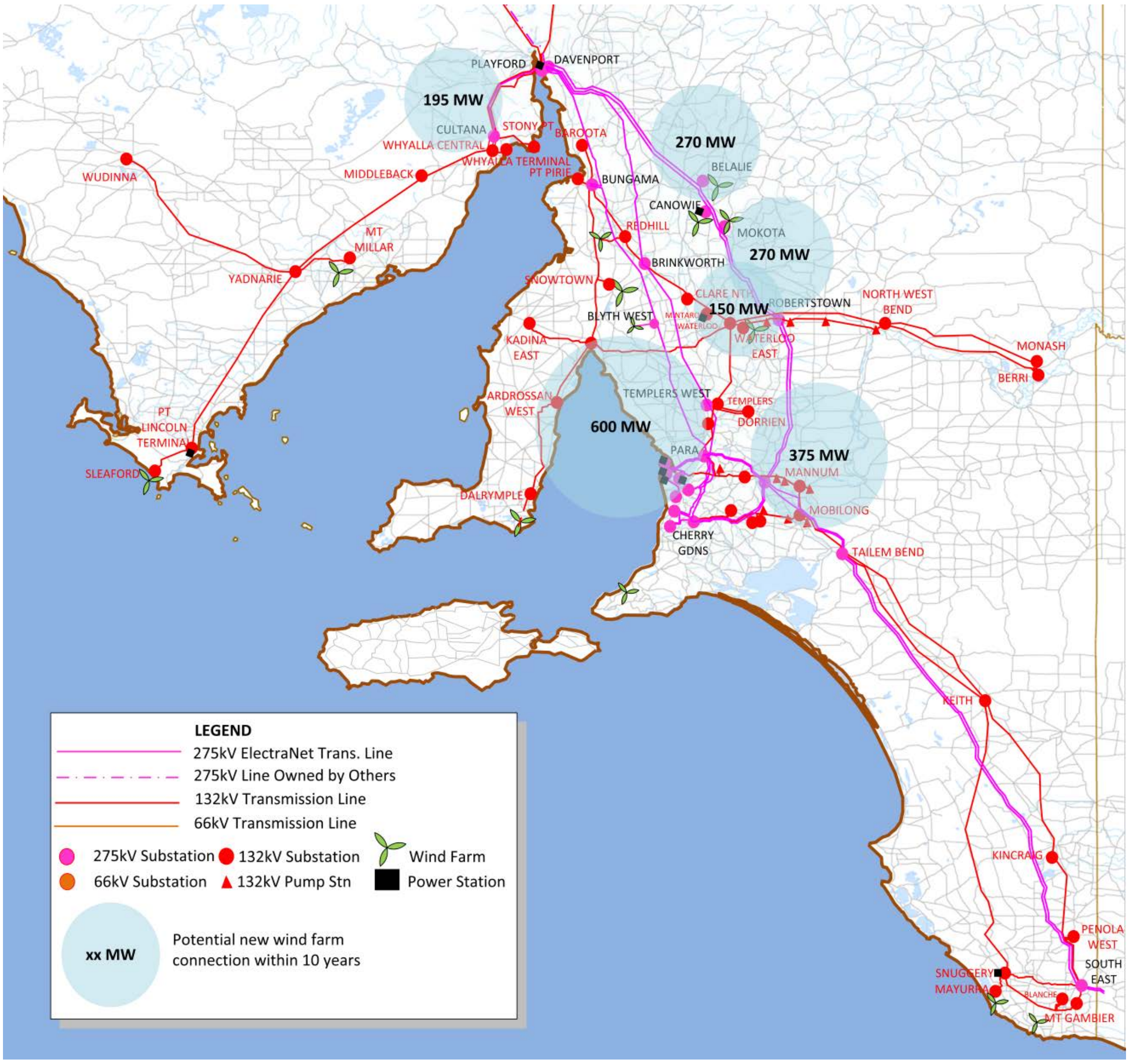


Figure 7-3: Potential future wind farm connections

7.5 Planning Scenario Analysis Outcomes

The detailed outcomes of the analysis of each of the planning scenarios are described in sections 7.6, 7.7 and 7.8. Table 7-4 summarises the high level outcomes of the analysis for each planning scenario.

Table 7-4: High level planning scenario outcomes

Scenario	10-year Planning Outcomes
Base	No significant projected network limitations
SA Mining Growth	Significant network augmentation required in specific parts of the network depending on actual mining developments driving this investment
SA Renewable Generation Expansion	Moderate network augmentation required to avoid significant network congestion at maximum demand times At low demand times wind generation output may be limited by the ability to export power from South Australia

7.6 Future Transmission Network Developments – Base Scenario

In addition to the committed and pending projects discussed in sections 7.2.2 and 7.2.3 respectively, the following network reinforcement projects are proposed within the next ten years.

7.6.1 Baroota substation upgrade

Scope of Work:	Replace plant that is in poor condition at Baroota Substation to bring the substation to the current minimum standard, including flood mitigation.
Estimated Cost:	$5-10 Million
Project Category:	Replacement/refurbishment
Timing:	November 2017
Project Status:	Proposed (Project Specification Consultation Report published)

Project Need:

An ElectraNet condition assessment report produced for the Baroota Substation in March 2012 indicates that the majority of the primary equipment is in poor condition. The existing 132 kV ganged interrupter and fuse arrangement are both out-dated and pose a safety hazard. Most of the secondary equipment is also in average to poor condition; the overall switchyard, plant layout and equipment are not in accordance with current ElectraNet design standards or good electricity industry practice. In addition, the existing substation is located on a road easement and is subject to potential flooding.

The ETC, until 1 December 2017, assigns the Baroota connection point to reliability category 1, requiring that equivalent transformer capacity at Baroota must be adequate to supply the AMD with all transformer(s) in service. From 1 December 2017, the ETC assigns Baroota to reliability category 2, meaning that the equivalent transformer capacity at Baroota must be adequate to supply the AMD with one transformer out of service. With only one transformer currently installed at Baroota and no currently-available network support arrangement, the existing connection point cannot meet the category 2 level of reliability from 1 December 2017.

ElectraNet has commenced public consultation in accordance with the RIT-T process. The Project Specification Consultation Report was issued in May 2014 and closed for submissions on 8 August 2014. One submission was received from generators and a late submission accepted from a non-network proponent.

ElectraNet has reviewed and revised the assumptions that underpinned the original analysis that resulted in the Baroota ETC change from category 1 to category 2. Changes include refining the impact of rooftop solar PV on demand and updating the VCR value for Baroota according to the latest VCR values published by AEMO[31].

ElectraNet has reviewed the economic analysis for the RIT-T based on the revised assumptions, which has resulted in a significantly lower market benefit than the original analysis. Given this reduction in market benefit, ElectraNet investigated an alternative

[31] AEMO: Value of Customer Reliability Review – Final Report - September 2014

network option with significantly reduced scope and cost and correspondingly lower levels of reliability, operability and flexibility for future expansion. However, the economic analysis shows that the least cost network solution to meet the category 2 reliability standard does not produce a net market benefit.

ElectraNet actively engaged with the non-network proponent to refine the technical and commercial characteristics of the solution it proposed. Despite the efforts of the proponent to reduce costs, the economic analysis shows that the identified non-network solution does not produce a net market benefit either.

In summary, the detailed option analysis of both network and non-network options has resulted in no technically feasible option being identified that meets the category 2 reliability standard and results in a positive net market benefit to customers. Given this outcome ElectraNet is engaging with ESCOSA seek to remove the requirement for category 2 reliability from 1 December 2017 at Baroota, as it appears this re-categorisation is not supported by the revised assumptions. It is considered that this approach is in the best interests of South Australian consumers. In the event that ESCOSA removes the ETC requirement, the Baroota project will reduce to only replacing equipment in poor condition and to address safety hazards.

However, the RIT-T option analysis has indicated that providing non-continuous N-1 equivalent transformer capacity at Baroota connection point may deliver positive net benefits to consumers. ElectraNet intends to explore this option further.

ElectraNet intends to publish a fuller summary of its analysis in a PADR for this project in mid-2015.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

Option Analysis

Table 7-5: Baroota substation upgrade - options considered

Option	Description	Comment	Estimated Cost ($ Million)
1	Replace plant in poor condition . Retain only the existing single 10 MVA 132/33 kV transformer	Flood mitigation and other works are required, with the existing 10 MVA transformer to be left in its current position This option depends on reaching agreement with ESCOSA to vary the requirement for category 2 reliability from 1 December 2017 at Baroota	5-10
2	Replace plant in poor condition and bring the site up to modern standards. Install a second 10 MVA 132/33 kV transformer	Analysis undertaken for the RIT-T shows that this option, which is the least expensive network solution to meet category 2 reliability standard, does not produce a net market benefit	10-18

Option	Description	Comment	Estimated Cost ($ Million)
3	Distribution solution - SA Power Networks to construct a second 33 kV line from Bungama to Baroota and install a 33 kV regulator including switchgear, telecommunications, and unit protection	An upgrade of the existing Baroota substation site would be required, as per Option 1	30-40
4	Generation network support	Discussions with a potential generation service provider to refine costs have shown that this option is not able to economically meet the category 2 reliability standard	NPV to be reported in forthcoming PADR
5	Demand side management	Demand side management cannot meet the category 2 reliability standard at this site, nor can it address the site refurbishment need. Hence, this is not a viable option	N/A

7.6.2 Install Additional 275 kV Switched Reactors

Scope of Work: Install two switched 50 Mvar 275 kV reactors at Para

Estimated Cost: $5-10 Million

Project Category: Security/Compliance

Timing: 2018 - 2023 (timing to be refined)

Project Status: Proposed

Project Need:

Very light net loading conditions (less than 1000 MW) have been observed on the South Australian transmission system during 2014. The lightest observed loading conditions have occurred in the middle of sunny, mild days on weekends or public holidays. The occurrence and severity of such conditions is anticipated to increase along with the increasing penetration of embedded solar PV installations. These conditions often correlate with periods of sustained high voltage levels on the South Australian transmission network.

Indicative studies have shown that following a single contingency of an in-service generator, steady-state voltage levels on the South Australian transmission system may breach 110% during the 2018 - 2023 period.

The SVCs located at Para were installed to ensure that stable voltage control could be maintained following a significant single contingency event. During the observed very light demand network conditions, the Para SVCs have often operated well into their inductive reactive range.

The installation of two switched 50 Mvar 275 kV reactors at Para would improve the ability to control pre- and post-contingency voltage levels on the South Australian transmission system during very light loading conditions. If properly coordinated, they would also effectively extend the inductive reactive range of the existing Para SVCs.

The preferred scope and required timing of this project will be more accurately determined by future detailed planning studies.

ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

7.7 Future Transmission Network Developments – SA Mining Growth Scenario

For the SA Mining Growth planning scenario, the following significant network augmentation projects are potentially required within the next ten years.

It is anticipated that most of the projects that are identified as required for the Base scenario will also be needed in the SA Mining Growth scenario. The single possible exception is the project to install additional 275 kV switched reactors (section 7.6.2), which may be able to be deferred if a significant new base load is connected.

7.7.1 Lower Eyre Peninsula Major Reinforcement

Scope of Work:	Construct a new double circuit 275 kV 600 MVA transmission line (strung on one side) between Cultana and Yadnarie and establish a new Yadnarie West 275/132 kV substation with one 200 MVA transformer. New load to be supplied via 275 kV and 132 kV connections at Yadnarie.
Estimated Cost:	$150-300 Million
Project Category:	Augmentation
Timing:	Within ten years
Project Status:	Proposed, subject to customer connection. RIT-T in-progress

Project Need:

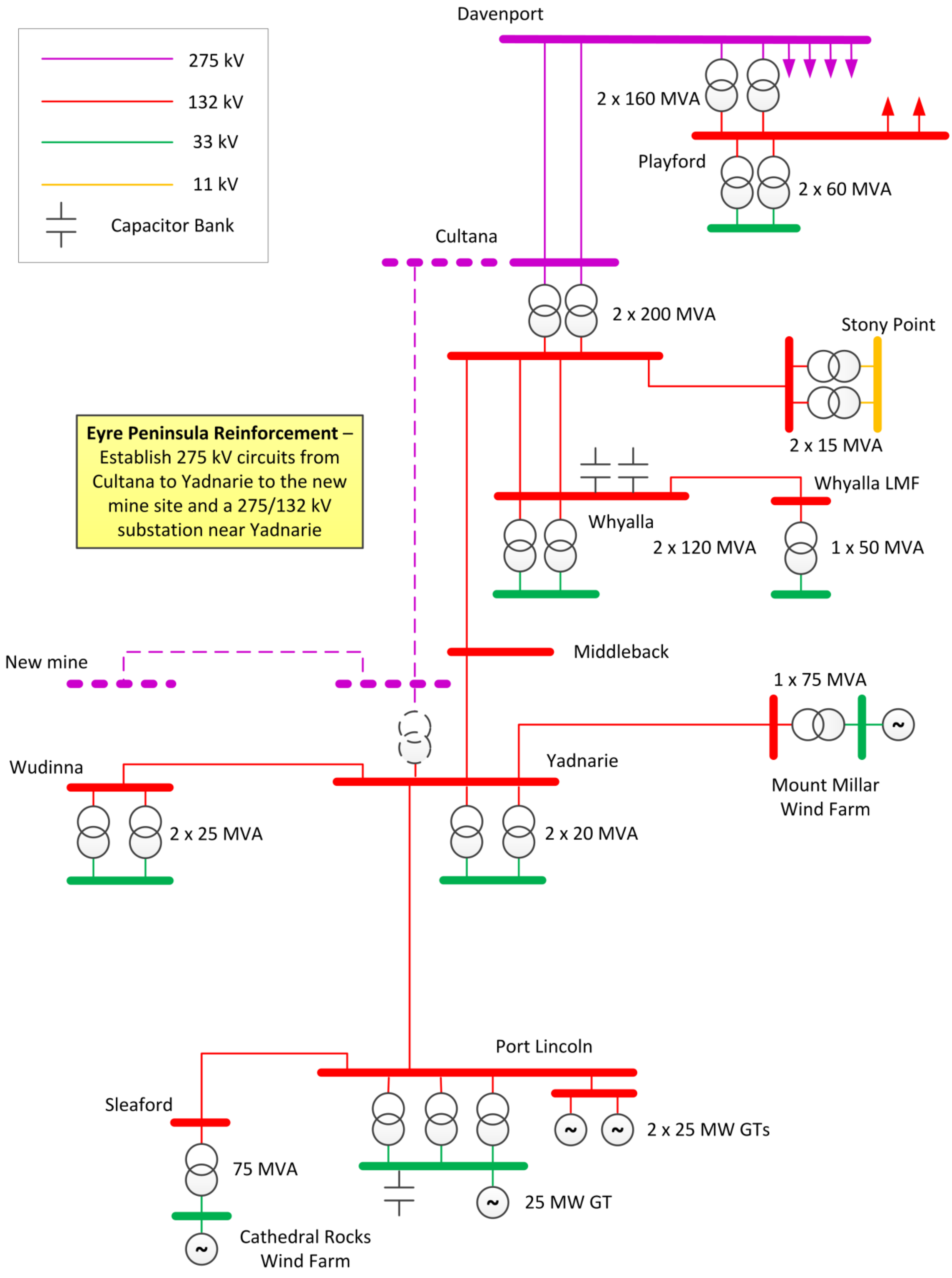
The Eyre Peninsula region has significant renewable and mineral resources, but currently limited electricity transmission infrastructure to support the development of those resources. This project will be required if a potential mine connects near Wudinna, with an associated port on the West Coast of Spencer Gulf (total new demand about 300 MW).

In January 2013, ElectraNet published a PADR as the second stage of the RIT-T consultation process regarding options for reinforcement of the Lower Eyre Peninsula transmission network. The PADR and non-confidential submissions from interested parties on the report are available from ElectraNet's website via the RIT-T Projects webpage.

ElectraNet is in on-going discussions with a number of potential connection applicants in relation to spot-load developments. The commitment of new spot loads (e.g. mining loads) in the region will derive the nature and timing of the network reinforcement. Consequently, ElectraNet does not intend to complete the RIT-T process until financial commitments from a new spot load have been secured, at which point the analysis presented in the PADR will be updated and the RIT-T will be progressed to a conclusion.

Figure 7-4 shows a potential configuration of the Eyre Peninsula transmission network that would be suitable to supply the increased Eyre Peninsula demand under this planning scenario.

Figure 7-4: Eyre Peninsula transmission network single line diagram: SA Mining Growth scenario



7.7.2 Yorke Peninsula Reinforcement

Scope of Work:	Construct a single circuit 275 kV line from Blyth West to Hummocks, and establish a new 275/132 kV injection point at Hummocks with a single 200 MVA transformer.
Estimated Cost:	$30-55 Million
Project Category:	Augmentation
Timing:	Subject to large customer connection
Project Status:	Proposed, subject to large customer connection

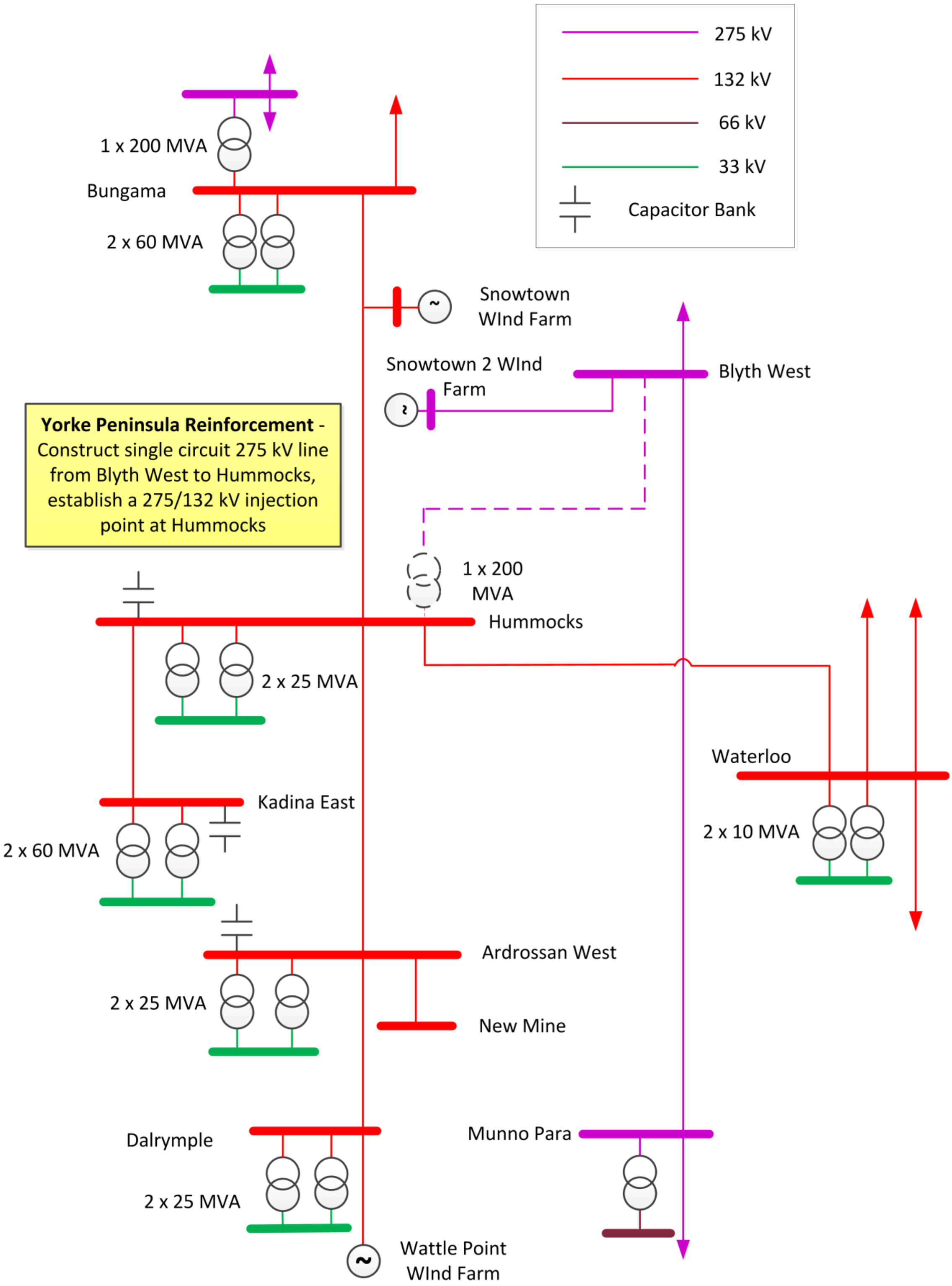
Project Need:

The Mid North 132 kV network has a very limited capacity to accommodate new large load connections. A tripping scheme could be implemented to accommodate a significant new step load increase on the Yorke Peninsula. However, this tripping scheme would reduce supply reliability to the new step load as a trade-off for provision of the new capacity.

To achieve a level of transmission supply reliability for the new step load that is comparable to that experienced by current customers, a new 275/132 kV injection point at Hummocks is proposed. This would provide a range of benefits, including improving network reliability for both mining and residential customers on the Yorke Peninsula, reducing 132 kV transmission line losses, improving voltage control, and reducing the occurrence of local wind farm constraints. ElectraNet intends to initiate a RIT-T when a large customer connection has been committed.

Figure 7-5 shows a potential configuration of the Yorke Peninsula transmission network that would be suitable to supply the increased Yorke Peninsula demand under this planning scenario.

Figure 7-5: Yorke Peninsula transmission network single line diagram: SA Mining Growth scenario



7.8 Future Transmission Network Developments – SA Renewable Generation Expansion Scenario

For the SA Renewable Generation Expansion scenario, the following network augmentation projects would potentially avoid significant congestion at peak demand times on the South Australian transmission network, if implemented within the next ten years.

At times of low demand and high wind generation in this planning scenario, particularly at times of high solar PV output, the amount of South Australian wind generation may be limited by the ability to export power from South Australia. One of the potential projects listed below would incrementally increase available export transfers across the Heywood interconnector, and another would firm up and incrementally increase available export transfers across the Murraylink interconnector. A more significant increase in the ability to export power from South Australia would be contingent on the ability of a new interconnector to provide net market benefits.

It is anticipated that all of the projects that are identified as required for the Base scenario will also be needed in the SA Renewable Generation Expansion scenario. The need for the proposed Security/Compliance project to install additional 275 kV switched reactors (section 7.6.2) may eventuate earlier than it would under the Base scenario.

7.8.1 Apply Dynamic Line Ratings to the Davenport to Robertstown 275 kV Lines

Scope of Work:	Remove various plant limits at Robertstown, Canowie, Davenport and Mokota (e.g. remove line traps, replace current transformers, change current transformer ratios) and apply dynamic line ratings to both 275 kV circuits between Robertstown and Davenport.
Estimated Cost:	Less than $5 Million
Project Category:	Market Benefit
Timing:	Within ten years
Project Status:	Subject to demonstration of net market benefits following further wind farm connections

Project Need:

Increased congestion is expected on the Davenport to Robertstown 275 kV lines under all demand conditions for this planning scenario.

In the event of the occurrence of this scenario, it is proposed to address various plant rating limits and apply dynamic ratings to these 275 kV lines. This work would increase the capacity of these lines, especially at times of high wind generation. This would significantly increase the capacity of these lines at times of high power flows and is likely to avoid the incidence of serious congestion on these lines.

7.8.2 Increase the Robertstown 275/132 kV Transformers' Rating

Scope of Work:	Remove various plant limits (e.g. change current transformer ratios) and apply short term loading limits to the Robertstown 275/132 kV transformers.
Estimated Cost:	Less than $5 Million
Project Category:	Market Benefit
Timing:	Within ten years
Project Status:	Subject to demonstration of net market benefit following further wind farm connections

Project Need:

Increased congestion is expected on the Robertstown 275/132 kV transformers at times of high wind generation under this planning scenario. Increasing the short term loading limits on the Robertstown 275/132 kV transformers would resolve this constraint.

7.8.3 Mid North 132 kV Control Scheme

Scope of Work:	Implement a control scheme to reconfigure the Mid North 132 kV network at times of high wind generation, to reduce the occurrence of constraints on 132 kV lines in the Mid North.
Estimated Cost:	Less than $5 Million
Project Category:	Market Benefit
Timing:	Within ten years
Project Status:	Subject to demonstration of net market benefit following further wind farm connections

Project Need:

Under this planning scenario, increased congestion on the 132 kV line corridor between Robertstown and Para is expected at times of high wind farm generation. Studies have indicated that a control scheme that, as required, opens and closes 132 kV circuit breakers in the Mid North network could be configured to target reduced congestion on Mid North 132 kV lines under varied operating conditions. Implementation of such a control scheme would significantly reduce the impact and occurrence of constraints on the Mid North 132 kV network.

7.8.4 Apply Dynamic Line Ratings to the Tungkillo to Heywood 275 kV Corridor

Scope of Work:	Remove various plant limits (e.g. replace current transformers, change current transformer ratios) and work with AusNet Services to apply dynamic ratings to 275 kV lines in the Tungkillo to Heywood corridor.
Estimated Cost:	Less than $5 Million
Project Category:	Market Benefit
Timing:	Within ten years
Project Status:	Subject to demonstration of net market benefit following further wind farm connections

Project Need:

Increased congestion is expected on the Tungkillo to Heywood 275 kV corridor during high export conditions for this planning scenario.

Applying dynamic ratings on the 275 kV lines in this line corridor would increase the available transfer on these lines at times of high wind generation. This would increase the export capacity of the Heywood interconnector at the times when it would be most needed under this planning scenario.

7.8.5 String Vacant Circuit Tungkillo to Tailem Bend 275 kV circuit

Scope of Work:	String the vacant circuit between Tailem Bend and Tungkillo 275 kV.
Estimated Cost:	$20-40 Million
Project Category:	Market Benefit
Timing:	Within ten years
Project Status:	Subject to demonstration of net market benefit following further wind farm connections

Project Need:

Increased congestion is expected on the Tungkillo to South East 275 kV corridor during high export conditions for this planning scenario.

Depending on the location of wind farms, adding additional thermal capacity between this corridor would increase the export capacity of the Heywood interconnector.

7.8.6 Uprate Riverland 132 kV Lines and Install Reactive Support at Monash

Scope of Work:	Uprate the Robertstown – North West Bend #2 and North West Bend – Monash #2 132 kV lines to 100 ˚C line clearances, and install two 15 Mvar capacitors at Monash
Estimated Cost:	$10-18 Million
Project Category:	Market Benefit
Timing:	Within ten years
Project Status:	Subject to demonstration of net market benefit

Project Need:

The ability to increase export transfers across the Murraylink interconnector may at times be limited by low voltage levels on the Riverland 132 kV network. This may limit South Australian export transfer levels at times of high wind farm output in South Australia.

The installation of up to two 15 Mvar 132 kV capacitors at Monash would improve 132 kV voltage levels on the Riverland 132 kV network during times of high power transfer through the Riverland, and support increased available exports across Murraylink interconnector.

7.9 Summary of Network Limitations and 10-Year Network Augmentation, Security and Compliance, and Replacements Projects

Table 7-6 lists the emerging network limitations that have been identified during analysis of the Base planning scenario. The solutions listed in Table 7-6 represent the committed, pending and proposed solutions based on evaluating network as well as non-network options using high level cost estimates. Each proposed solution is one of potentially several options available to resolve the corresponding network limitation. To provide an overview of all augmentation projects Table 7-6 includes the committed and pending projects covered in sections 7.2.2 and 7.2.3 respectively

The proposed solutions are subject to variation and change due to customer activity, network developments and refined analysis. Due to uncertainties in the timing and number of customer connections within the state, the projects are indicative in terms of timing and the scope of work. The proposed solution for each network limitation will be updated as more information becomes available.

Projects that are related to the continuing maintenance of ElectraNet's security and compliance obligations are listed in Table 7-7.

Table 7-8 lists proposed significant asset replacement projects (>$3M at a single site), which are planned based on asset condition. Asset condition monitoring is used to determine the actual timing of any asset replacement. Where possible, replacement projects are timed with augmentation projects to minimise unnecessary mobilisation and overhead costs.

ElectraNet does not presently consider that there are any non-network solutions that are economically feasible that could resolve the network limitations presented in Table 7-8.

ElectraNet is currently assessing asset condition and asset replacement requirements for the 2018 - 2023 regulatory control period. Table 7-8 contains summary entries for line, substation and protection system unit asset replacements in this period. ElectraNet plans to further expand the detail related to those summary line entries in preparation for submission of the 2018 – 2023 revenue proposal, which is due in January 2017. More details will be available for inclusion in the 2016 Transmission Annual Planning Report.

Table 7-6: Committed, pending, proposed and potential augmentation projects

Project Timing	Limitation	Proposed solution	Category	Region	Estimated Cost ($M)
	Committed and Pending Projects				
2015	Load growth in the Northern Suburbs overloads SA Power Networks' 66 kV network	Establish Munno Para substation and install a single 225 MVA 275/66 kV transformer supplying into the Northern Suburbs	Connection	Metropolitan	30-35 (ElectraNet costs only)
2015	Robertstown-North West Bend #1 132 kV line overloaded for loss of Robertstown-MWP3-MWP2-MWP1 - North West Bend #2 132 kV line at high demand times, as Western Victorian 220 kV network is unable to support Murraylink transfer into South Australia at times of high Victorian demand	Uprate the Robertstown – North West Bend #1 132 kV line to 100 ˚C line clearances	Augmentation / Market Benefit	Riverland	<3
2016	Heywood Interconnector transfer limitations due to system stability and thermal constraints	Install 50% series compensation on the South East – Tailem Bend 275 kV lines; remove rating restrictions from South East 275 kV and 132 kV lines; implement a run-back control scheme for Lake Bonney Wind Farm to manage light load and high wind condition; SP AusNet to install a third 500/275 kV transformer at Heywood	Augmentation / Market Benefit	Main Grid and South East	40-50 (ElectraNet costs only)
2016	ETC reclassification to category 2 required N-1 transformer redundancy at Dalrymple connection point from 1 December 2016	Install a second 25 MVA transformer and associated switchgear at Dalrymple substation	Connection	Mid North	14-16 (ElectraNet costs only)
2016	Deterministic line ratings in various parts of the network can cause constraints at times of high demand or high wind generation	Install modern weather stations at various monitoring locations to facilitate the future implementation of dynamic line ratings on critical circuits	Augmentation / Market Benefit	Various	<5

Project Timing	Limitation	Proposed solution	Category	Region	Estimated Cost ($M)
	Proposed Projects (All Scenarios)				
2018	Difficulty with manually controlling the increasing number of reactive plant and voltage control facilities across the Main Grid effectively	Install a coordinated control scheme to better utilise existing reactive plant and voltage control facilities to minimise system constraints whilst managing system voltage levels	Augmentation	Main Grid/ Various	<5
2018 - 2023	Deterministic line ratings in various parts of the network can cause constraints at times of high demand or high wind generation	Complete roll out of weather stations at monitoring locations across the network and complete validation of real-time line ratings on specific circuits	Augmentation / Market Benefit	Various	<5
	Potential Projects (SA Mining Growth Scenario)				
When or if needed: within 10 years?	Subject to connection of a new large mining load on the Eyre Peninsula, at high demand times the Middleback – Yadnarie 132 kV line will be overloaded under normal conditions and one Cultana 275/132 kV transformer will be overloaded for an outage of the other	Reinforce the Eyre Peninsula by constructing a double-circuit 275 kV line from Cultana to a location near Yadnarie, initially strung only on one side; establish a 275/132 kV substation near Yadnarie; provide supply to the new mining load(s) via 275 kV and 132 kV supplies from the new substation	Augmentation	Eyre Peninsula	150-300
When or if needed: within 10 years?	Subject to connection of a new large mining load on the Yorke Peninsula, at high demand times when either the Bungama – Hummocks or the Waterloo – Hummocks 132 kV line is out of service, the other line may be overloaded and it may not be possible to maintain adequate voltage levels on Yorke Peninsula	Reinforce the Yorke Peninsula by constructing a single circuit 275 kV line from Blyth West to Hummocks and install a single 200 MVA 275/132 kV transformer at Hummocks substation	Augmentation	Mid North	40-55

Project Timing	Limitation	Proposed solution	Category	Region	Estimated Cost ($M)
	Potential Projects (SA Renewable Generation Expansion Scenario)				
When or if needed: within 10 years?	Subject to connection of new wind farms to the 275 kV lines between Davenport and Robertstown, those 275 kV lines may be overloaded at times of high wind generation	Increase the capacity of the 275 kV lines between Davenport and Robertstown by upgrading various items of plant (e.g. remove line traps, replace current transformers, change current transformer ratios) and apply dynamic line ratings to these lines	Market Benefit	Main Grid	<5
When or if needed: within 10 years?	Subject to connection of new wind farms to the 275 kV lines between Davenport and Robertstown, one of the Robertstown 160 MVA 275/132 kV transformers may be overloaded for an outage of the other transformer	Increase the capacity of the Robertstown 275/132 kV transformers by upgrading various items of plant and apply short term loading limits to the Robertstown 160 MVA 275/132 kV transformers	Market Benefit	Main Grid/ Mid North	<5
When or if needed: within 10 years?	Subject to connection of new wind farms to the Mid North 132 kV lines or the 275 kV lines between Davenport and Para (the “East” and “West” circuits), the thermal rating of various 132 kV lines in the Mid North may constrain wind farm generation dispatch, based on the need to avoid overloading lines following a single credible contingency	Implement a control scheme that will reconfigure the Mid North 132 kV network at times of high wind farm generation by opening and closing 132 kV circuit breakers as required to target reduced congestion under various operating conditions	Market Benefit	Mid North	<5
When or if needed: within 10 years?	Subject to the connection of new wind farms in South Australia, increased congestion on the 275 kV network between Tungkillo and Heywood is forecast to limit exports from South Australia to Victoria	Increase the capacity of the 275 kV lines between Tungkillo and Heywood by upgrading various items of plant (e.g. remove line traps, replace current transformers, change current transformer ratios) and apply dynamic line ratings to these lines	Market Benefit	Main Grid	<5

Project Timing	Limitation	Proposed solution	Category	Region	Estimated Cost ($M)
When or if needed: within 10 years?	Subject to the connection of new wind farms in South Australia, increased congestion on the 275 kV network between Tungkillo and Tailem Bend is forecast to restrict exports from South Australia to Victoria across the Heywood interconnector	Increase the capacity of the Tungkillo to Tailem Bend 275 kV corridor by stringing the vacant 275 kV circuit between Tungkillo and Tailem Bend	Market Benefit	Main Grid	25-50
When or if needed: within 10 years?	Subject to the connection of new wind farms in South Australia, increased congestion on the 132 kV network between Robertstown and Monash is forecast to restrict exports from South Australia to Victoria across the Murraylink interconnector	Uprate the Robertstown –North West Bend #2 and the North West Bend-Monash #2 132 kV lines to 100 ˚C line clearances and install two switched 15 Mvar 132 kV capacitor banks at Monash	Market Benefit	Riverland	10-18

Table 7-7: Committed, pending and proposed security and compliance projects

Project Timing	Limitation	Proposed solution	Region	Estimated Cost ($M)
	Committed and Pending Projects			
2015	Substandard circuit breaker arrangement at South East substation constrains the Heywood Interconnector and places network security and reliability at risk	Install additional circuit breakers and associated switchgear, metering and protection at South East substation	Main Grid	5-10
2016	Substandard circuit breaker arrangement at Tailem Bend substation constrains the Heywood Interconnector and places network security and reliability at risk	Extend the Tailem Bend substation to accommodate an additional 275 kV diameter, with two circuit breakers, associated plant, secondary systems and rearrange 275 kV line exits	Main Grid	10-18
2016	Changing generation patterns have resulted in complex voltage interactions on the Eyre Peninsula and Upper North regions leading to potential violations of voltage limits stipulated in the Rules and connection agreements	Install automated regional voltage control schemes for Eyre Peninsula and Upper North regions	Eyre Peninsula/ Upper North	<5
	Proposed Projects			
2018	The Bungama to Baroota 132 kV line was constructed to British clearance standards applicable at the time and does not meet Australian clearance standards	Raise spans on the Bungama to Baroota 132 kV line to maintain the required rating of 49˚C using Australian clearance standards	Mid North	<5
2018	Transformer oil containment systems need refurbishment to maintain compliance with environment protection regulations	Install, upgrade or replace transformer oil containment systems and associated equipment at various sites, where assessment indicates a clear need	Various	5-10
2018	Compliance with Rules chapter 4 security provisions becoming operationally difficult, with opportunities to do critical network maintenance and construction work reduced to very restrictive windows	Install integrated control scheme(s) at strategic locations in the network to ensure compliance to the 'next contingency' Rules security requirements and allow higher utilisation of the network under system normal conditions as well as provide the opportunity to do more network maintenance as required	Various	5-10

Project Timing	Limitation	Proposed solution	Region	Estimated Cost ($M)
2018	Shutdown of regionally important substations required during outages of Cultana to Yadnarie 132 kV transmission line	Install Eyre Peninsula islanding control scheme to minimise interruptions to customers	Eyre	<5
2018	Outages and constraints on the Murraylink Interconnector	Redesign and replace the Murraylink Control Scheme	Riverland	<5
2018	High voltage switching training conducted on live network results in network and asset performance impacts and training limitations	Create a high voltage switching training facility to improve training standards across all aspects of high voltage switching	Metropolitan	5-10
2018 - 2023	Substandard circuit breaker arrangement at Kilburn substation places network security and reliability at risk	Install additional 275 kV circuit breaker at Kilburn to complete the mesh	Metropolitan	<5
2018 - 2023	Following a single contingency of an in-service generator, steady-state voltage levels on the South Australian transmission system may breach 110% during the 2018 - 2023 period	Install two switched 50 Mvar 275 kV reactors at Para	Main Grid	5-10
2018 - 2023	Hallett wind farm generation constrained during outages of the Canowie to Robertstown 275 kV transmission line	Install a 275 kV circuit breaker and associated equipment on the Robertstown exit at Canowie substation	Main Grid	<5
2018 - 2023	Significant constraint on wind generation on outage of Snuggery to South East 132 kV transmission line	Uprate the Snuggery to Blanche to Mt Gambier 132 kV transmission line and associated low-rated primary plant	South East	<5
2018 - 2023	Generation constraints and/or loss of load during plant outages at Blanche substation	Install an additional 132 kV circuit breaker and associated equipment at Blanche substation	South East	<5
2018 - 2023	Loss of load at Back Callington, Kanmantoo and Murray Bridge - Hahndorf pumping stations #2 and #3 during an outage of the Mount Barker to Mobilong 132 kV transmission line	Install a meshed 132 kV bus with four exits and associated primary and secondary equipment at or adjacent to the existing Murray Bridge - Hahndorf pumping station #3 site	Eastern Hills	10-15

Project Timing	Limitation	Proposed solution	Region	Estimated Cost ($M)
2018 - 2023	Either Murraylink interconnection or generation north of Robertstown must be constrained during scheduled maintenance of centre breakers or associated plant at Robertstown substation	Install a single 275 kV circuit breaker and associated equipment between the 275 kV busses at Robertstown substation	Mid North / Murraylink Inter-connector	5-10
2018 - 2023	Both Mintaro and Angaston generators are constrained off during 132 kV outages that result in these generators being radialised	Implement full single pole reclosing capability on the 132 kV circuits in the Mid North region	Mid North	<5
2018 - 2023	Both Ladbroke Grove and Snuggery generators are constrained off during 132 kV outages that result in these generators being radialised	Implement full single pole reclosing capability on the 132 kV circuits in the South East region	South East	<5

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Table 7-8: Committed, pending and proposed replacement projects

Project timing	Limitation	Recommended solution	Region	Estimated cost ($M)	Alternative option(s)
	Committed and Pending Projects				
2015	Revenue meters at various connection points are at end-of-life, with increasing failure rates and no longer supported by manufacturer Note that this project previously addressed instrument transformers that are non-compliant with NEC metering requirements, but this limitation is now being addressed by ElectraNet's unit asset replacement program	Replace all end-of-life revenue meters	Various	<5	Replace revenue meters as they fail
2015	Mount Gunson substation plant at end of technical life; 132/33 kV transformer condition assessment indicates replacement is required	Replace selected end-of-life plant at Mt Gunson substation with modern-day equipment and install a new 10 MVA 132/33 kV transformer	Upper North	6-8	Rebuild entire substation adjacent to existing substation
2015	Porcelain disc insulators on Brinkworth to Mintaro 132 kV line at end of life, leading to high failure rate and fire start risk	Replace all porcelain disc insulators on Brinkworth to Mintaro 132 kV line, achieving a 15-year life extension	Mid North	5-7	Assess and replace insulators on sample-based testing results
2015	Neuroodla substation at end of technical life; 132/33 kV transformer condition assessment indicates replacement is required	Rebuild Neuroodla substation within the existing substation site, installing a new 10 MVA 132/33 kV transformer and modern-day equipment	Upper North	6-8	Replace selected substation plant based on condition or Rebuild entire substation adjacent to existing substation

Project timing	Limitation	Recommended solution	Region	Estimated cost ($M)	Alternative option(s)
2015	Porcelain disc insulators on Tailem Bend to Keith #2 132 kV line at end of life, leading to high failure rate and fire start risk	Replace all porcelain disc insulators on Tailem Bend to Keith #2 132 kV line, achieving a 15-year life extension	South East	5-10	Assess and replace insulators on sample-based testing results
2016	Some primary plant and most secondary systems at Para substation are in poor condition, not to modern-day standards and are a security and reliability risk. The structural integrity of the existing control building is of concern	Replace the 275 kV, 132 kV and 66 kV secondary systems, associated telecommunications systems, control buildings and selected primary plant at Para substation The project scope and schedule have been extended to include unit asset replacements required in the 2013-2018 period	Metropolitan	48-52	Refurbish individual assets or Replace assets on failure or Rebuild substation
2016	Morgan to Whyalla pumping station #2 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the Morgan to Whyalla pumping station #2 supply site to current day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Riverland	15-20	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites
2016	Morgan to Whyalla pumping station #1 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the Morgan to Whyalla pumping station #1 supply site to current day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Riverland	12-16	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites

Project timing	Limitation	Recommended solution	Region	Estimated cost ($M)	Alternative option(s)
2016	Morgan to Whyalla pumping station #3 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the Morgan to Whyalla pumping station #3 supply site to current day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Riverland	10-15	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites
2016	Morgan to Whyalla pumping station #4 primary plant at end of technical life; site not aligned with current environmental practices and company practices	Rebuild the Morgan to Whyalla pumping station #4 supply site to current day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Mid North	10-15	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites
2017	Mannum to Adelaide pumping station #2 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the Mannum to Adelaide pumping station #2 supply site to modern-day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Eastern Hills	8-12	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites
2017	Mannum to Adelaide pumping station #3 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the Mannum to Adelaide pumping station #3 supply site to modern-day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Eastern Hills	8-12	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites

Project timing	Limitation	Recommended solution	Region	Estimated cost ($M)	Alternative option(s)
2017	Mannum to Adelaide pumping station #1 primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the Mannum to Adelaide pumping station #1 supply site to modern-day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Eastern Hills	10-15	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites
2017	Millbrook pumping station primary plant at end of technical life; site not aligned with current environmental practices and company policies	Rebuild the Millbrook supply site to modern-day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Eastern Hills	10-15	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites
2018	Load releasing cross arms on Para-Brinkworth-Davenport 275 kV line are a safety risk and inadequate for access and maintenance. Porcelain disc insulators at end of life, leading to high failure rate and fire start risk	Replace load releasing cross arms and all porcelain disc insulators on Para-Brinkworth-Davenport 275 kV line, achieving a 15-year life extension	Main Grid	46-60	Rebuild 275 kV line in an adjacent easement and retire old line or Replace load releasing cross arms with standard cross arms (and also strengthen the towers) and assess and replace insulators on sample-based testing results

Project timing	Limitation	Recommended solution	Region	Estimated cost ($M)	Alternative option(s)
	Proposed Projects				
2016	Condition of the existing Para SVCs secondary systems and the lack of spare parts make maintenance impossible and manufacturer support is largely withdrawn. Failure would severely constrain interconnector transfer capacity	Replace the existing SVC thyristor valves, thyristor valve cooling, protection and control systems for both SVCs at Para substation with modern-day equipment	Main Grid	12-20	Replace individual components that are reaching end of life or Replace control systems only
2017	The majority of the primary equipment at Baroota substation is in poor condition	Replace plant in poor condition at Baroota substation and implement flood mitigation measures. Retain only the existing single 10 MVA 132/33 kV transformer. This option depends on reaching agreement with ESCOSA to vary the requirement for category 2 reliability from 1 December 2017 at Baroota	Mid North	5-10 (ElectraNet costs only)	Replace plant in poor condition. Install a second 10 MVA 132/33 kV transformer to meet category 2 reliability standard or Replace plant in poor condition. Engage non-network service provider to meet category 2 reliability standard or Replace plant in poor condition. Engage non-network service provider to implement non-continuous generation support to provide a net market benefit to consumers

Project timing	Limitation	Recommended solution	Region	Estimated cost ($M)	Alternative option(s)
2018	AC auxiliary supplies at older substations are not compliant with current Australian standards and have some safety hazards and operational deficiencies	Replace AC auxiliary supply equipment, switchboards and cabling at 13 substations	Various	<5	Replacing sub-standard and hazardous equipment is considered to be the only viable option
2018	A number of substation battery charger units have reached the end of their practical life. Also, spare parts are not available	Planned replacement program to remove battery chargers from service and replace with modern, fit-for-purpose equipment	Various	<5	Replace battery chargers on failure
2013 - 2018	Substation assets have been identified with high failure rates, safety risks or assessed to be at the end of their technical and economic lives	Program of unit asset replacements at 34 substations	Various	50-60	Replace individually selected assets on failure
2018 - 2023	Many items of online condition monitoring equipment are nearing the end of their usable lives (12-20 years old) and are exhibiting high failure rates	Replace obsolete online asset condition monitoring equipment	Various	8-12	Continue corrective maintenance program only
2018 - 2023	Review of substation lighting identified compliance issues and safety hazards with some existing lighting systems	Replace substation lighting and associated infrastructure at sites where hazards exist	Various	4-8	Cost and risks assessments were undertaken for the various lighting functions to determine the optimal solution to meet the requirements under the WHS Act and Australian Standards

Project timing	Limitation	Recommended solution	Region	Estimated cost ($M)	Alternative option(s)
2018 - 2023	Transmission line asset components at end of life, leading to high failure rate and fire start risk	Program of transmission line refurbishment to renew line asset components and extend line life	Various	100-130	Replace individual components or sections on failure or Full line replacement
2018 - 2023	Substation assets have been identified with high failure rates, safety risks or assessed to be at the end of their technical and economic lives	Program of unit asset replacements at various substations	Various	20-30	Replace assets on failure
2018 - 2023	Various individual substation protection systems have been assessed to be at the end of their technical and economic lives. Increased risk of failure could cause safety and reliability issues	Replace 400-500 protection scheme relay assets	Various	30-40	Replace assets on failure
2018 - 2023	Many items of online condition monitoring equipment are nearing the end of their usable lives (12-20 years old) and are exhibiting high failure rates	Replace obsolete online asset condition monitoring equipment.	Various	10-15	Continue corrective maintenance program only
2018 - 2023	Leigh Creek Coalfield reactors 1 and 2 have been assessed to be at the end of their technical lives and at high risk of failure	Replace the existing reactors with two new 33 kV reactors at Leigh Creek Coalfield substation	Upper North	10-15	Replace assets on failure
2018 - 2023	Leigh Creek Coalfield transformers 1 and 2 have been assessed to be at the end of their technical lives and at high risk of failure	Replace the existing transformers with two new 132/33 kV transformers at Leigh Creek Coalfield substation	Upper North	10-15	Replace assets on failure

Project timing	Limitation	Recommended solution	Region	Estimated cost ($M)	Alternative option(s)
2018 - 2023	Leigh Creek South transformers 1 and 2 have been assessed to be at the end of their technical lives and at high risk of failure	Replace the existing transformers with two new 132/33 kV transformers at Leigh Creek South substation	Upper North	10-15	Replace assets on failure
2018 - 2023	Mannum transformers 1 and 2 have been assessed to be at the end of their technical lives and at high risk of failure	Replace the existing transformers with two new 132/33 kV transformers at Mannum substation	Eastern Hills	10-15	Replace assets on failure
2018 - 2023	Mount Gambier transformer 1 has been assessed to be at the end of its technical life and at high risk of failure	Replace the existing 50 MVA transformer with a new 25 MVA 132/33/11 kV transformer at Mount Gambier substation	South East	4-8	Replace asset on failure

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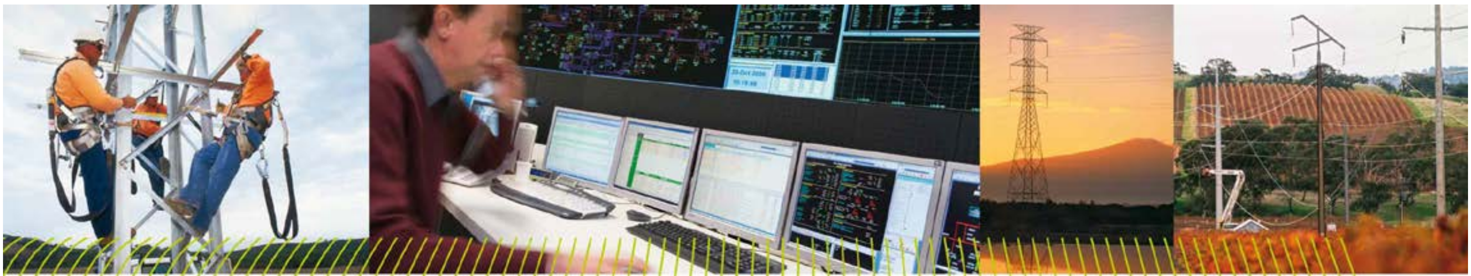
Appendices

May 2015



Appendix A Regional Network Maps

Figure A-1: Metropolitan Transmission Network and Supply Region

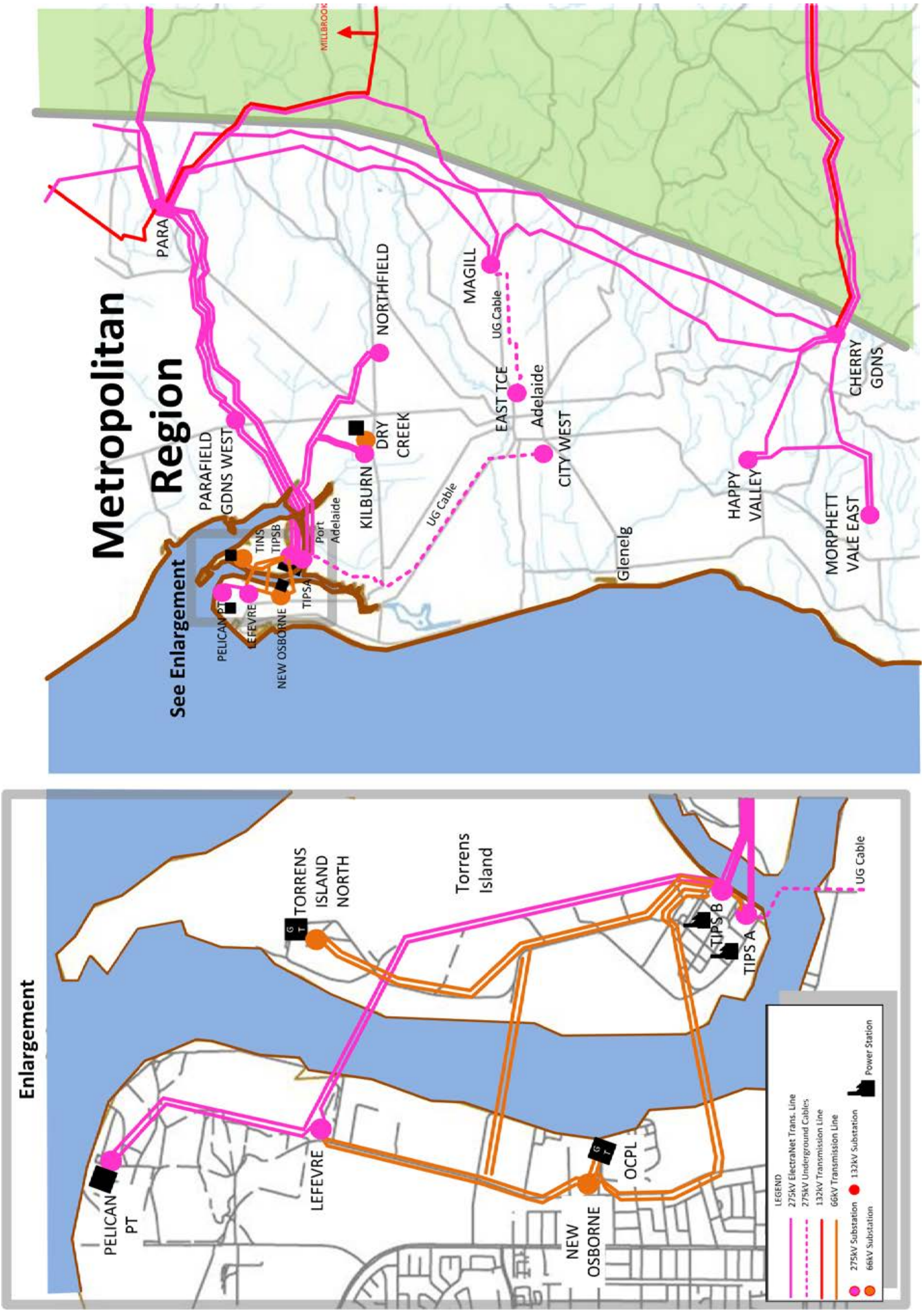


Figure A-2: Eastern Hills Transmission Network and Supply Region

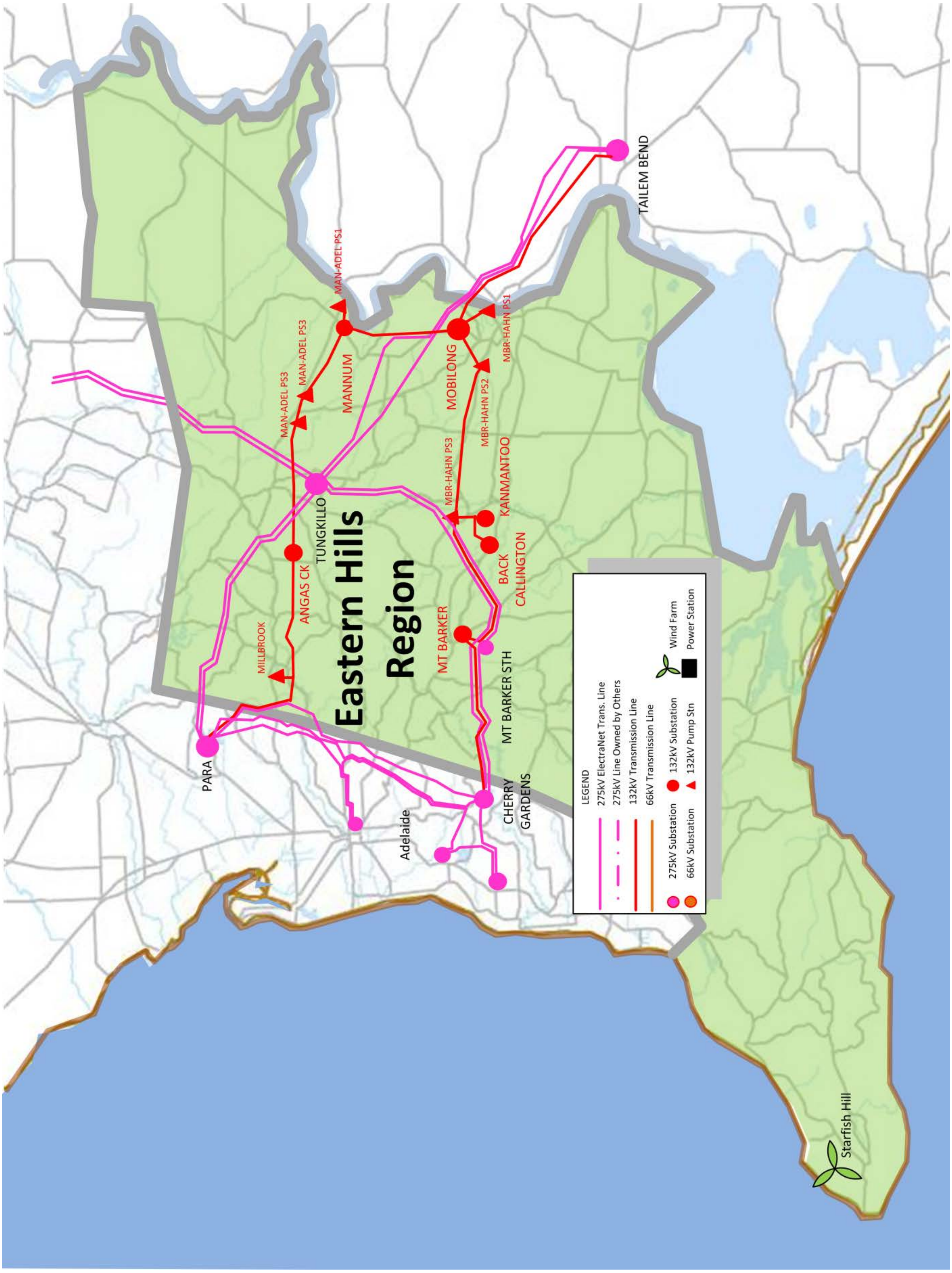


Figure A-3: Mid North Transmission Network and Supply Region

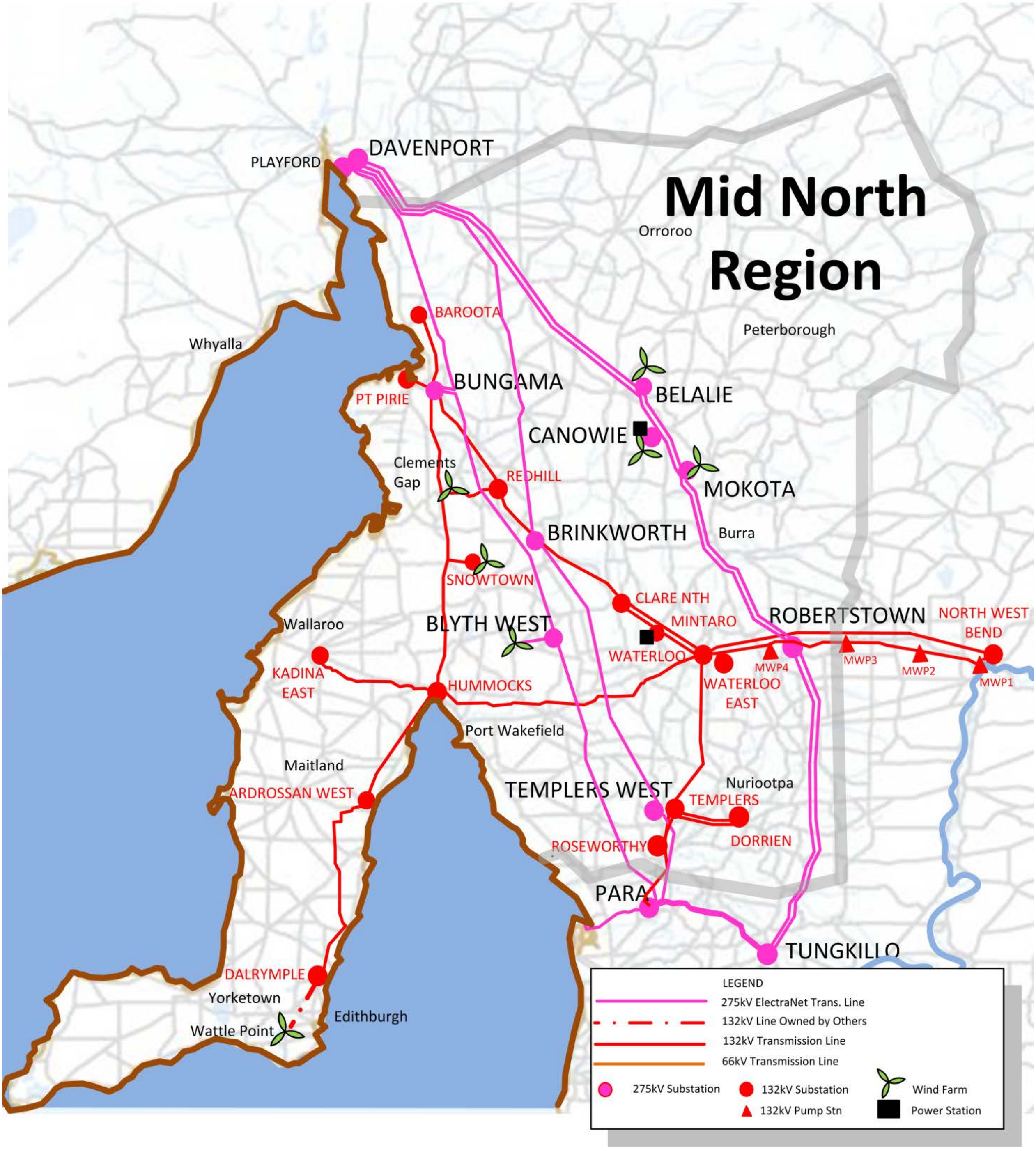


Figure A-4: Riverland Transmission Network and Supply Region

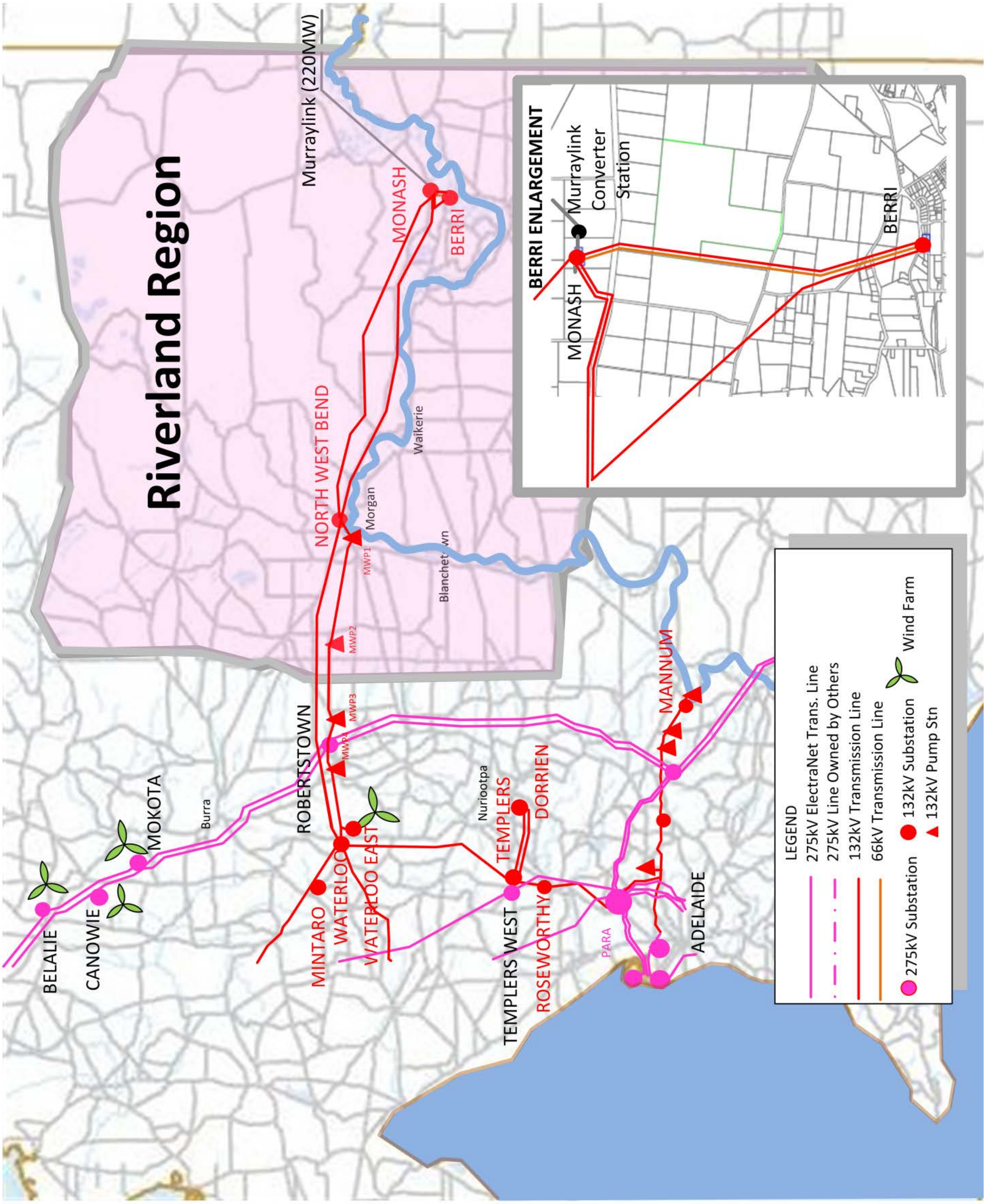


Figure A-5: South East Transmission Network and Supply Region

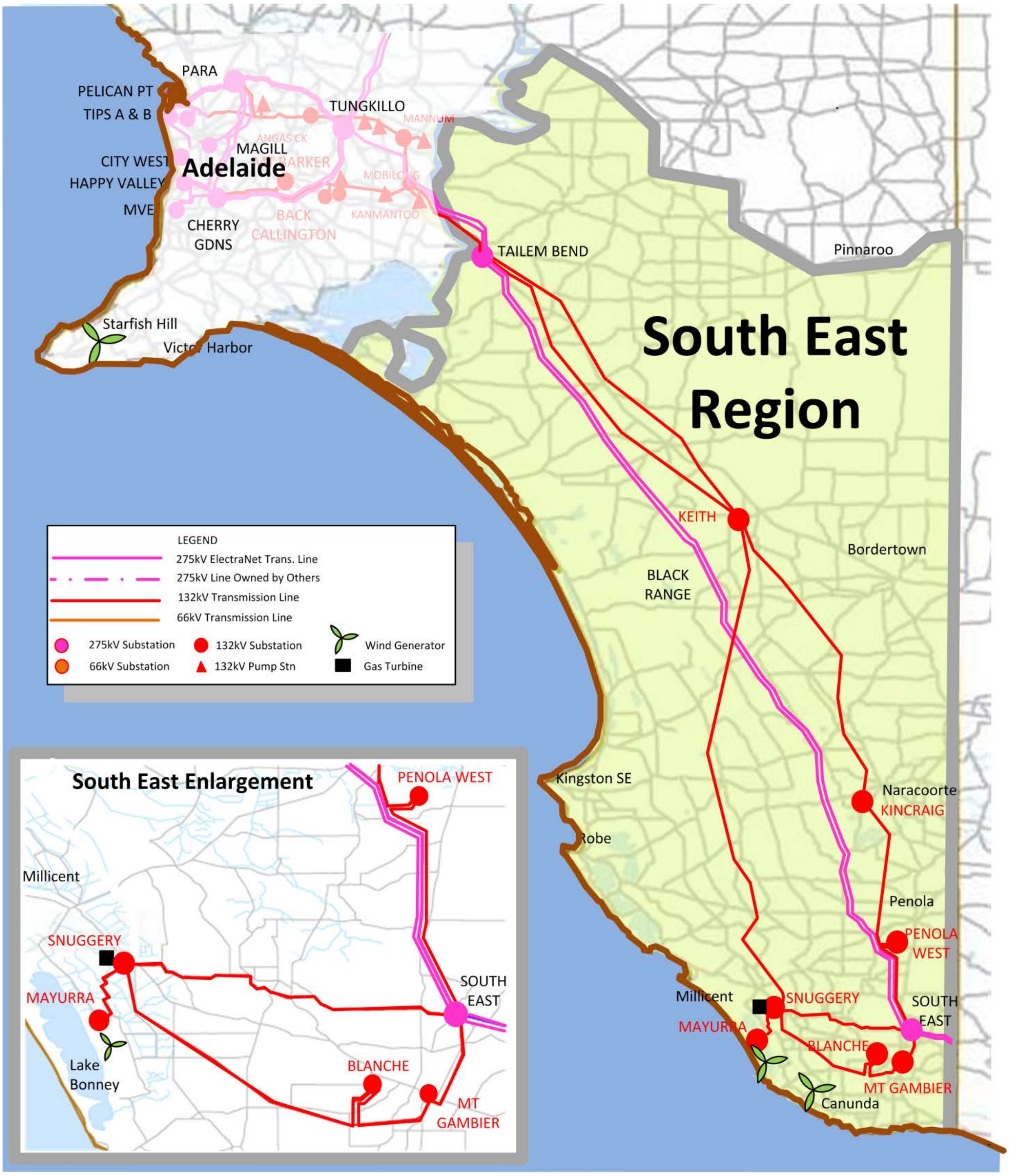


Figure A-6: Eyre Peninsula Transmission Network and Supply Region

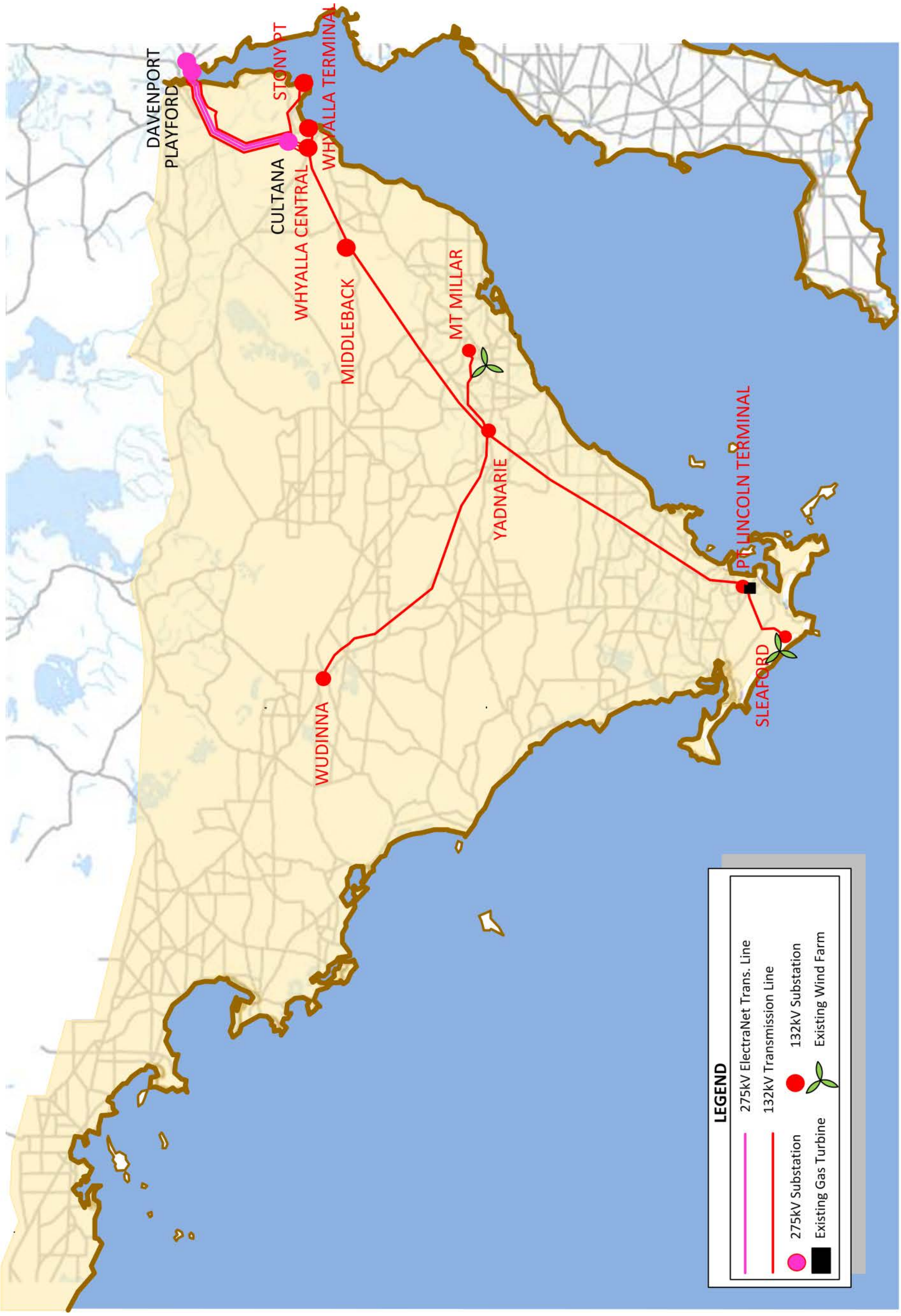
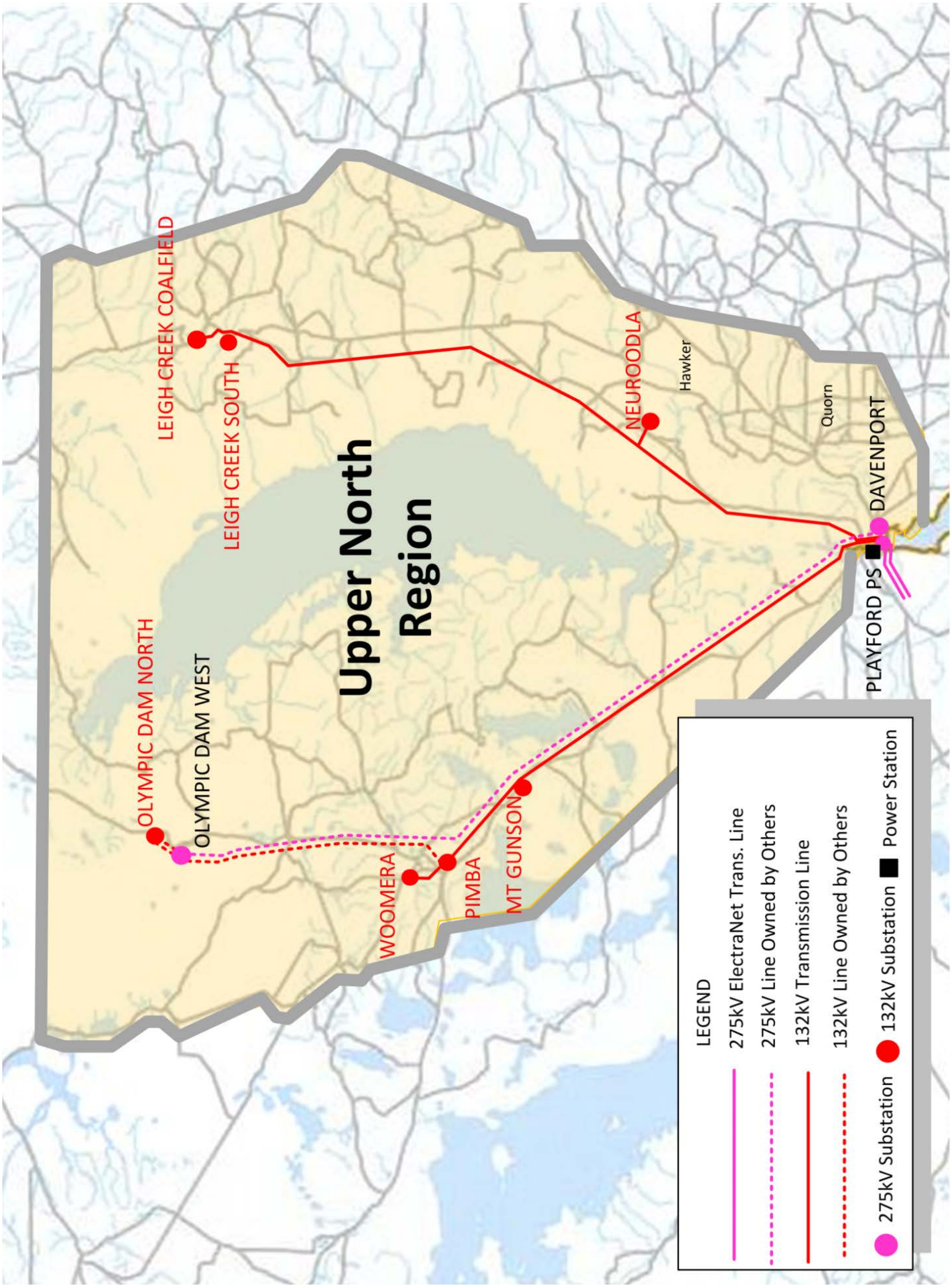


Figure A-7: Upper North Transmission Network and Supply Region



Appendix B Generator Expansion Forecast

Table B-1: SA Generator Expansion Forecasts by 2023-24

Scenario	South East (SESA)	Adelaide (ADE)	Northern South Australia (NSA)
Base	No change	No change	No change
SA Mining Growth	No change	No change	No change
SA Generation Expansion	Wind: +375 MW	Wind: +600 MW	Wind: +885 MW
2014 NTNDP (AEMO)		Wind: +796 MW	

Appendix C Updated Interconnector Limit Equations

The import capability of the Heywood interconnector due to long term voltage stability under system normal operating conditions has been revised to take into account of all recently completed projects in South Australia. These updated SA system normal import equations are shown below.

Long Term Voltage Stability Transfer Capability

SA Import Transfer Capability [MW] =

C1*SESA DEM + C2*LAD + C3*LB1 + C4*CAN + C5*LB2 + C6*LB3 + C7*SNUG + C8*SALGEN + CONST

Where:

SESA DEM	=	Total South-East Region Demand in MW (Keith, Kincraig, Snuggery, Blanche, Mt Gambier, Penola West)
C1	=	2.07
Lad	=	Ladbroke Grove Power Station output in MW
C2	=	-0.71
LB1	=	Lake Bonney Wind farm Stage 1 output in MW
C3	=	-0.85
Can	=	Canunda Wind farm output in MW
C4	=	-0.92
LB2	=	Lake Bonney Wind farm Stage 2 output in MW
C5	=	-0.98
LB3	=	Lake Bonney Wind farm Stage 3 output in MW
C6	=	-0.98
Snug	=	Snuggery Power Station output in MW
C7	=	-0.73
SALGEN	=	South Australia’s largest single in-service generator in MW (largest potential generation loss under a single credible contingency)
C8	=	-1.22
Const	=	736

Short Term Voltage Stability Transfer Capability

The import capability of the Heywood interconnector due to short term voltage stability under system normal operating conditions has also been revised and it is defined by the following Equation:

SA Import Transfer Capability [MW] =

C1*SESA DEM + C2*LAD + C3*LB1 + C4*CAN + C5*LB2 + C6*LB3 + C7*SNUG + C8*SALGEN + CONST

Where:

SESA DEM	=	Total South-East Region Demand in MW (Keith, Kincraig, Snuggery, Blanche, Mt Gambier, Penola West)
C1	=	1.37
Lad	=	Ladbroke Grove Power Station output in MW
C2	=	-0.41
LB1	=	Lake Bonney Wind farm Stage 1 output in MW
C3	=	-0.82
Can	=	Canunda Wind farm output in MW
C4	=	-0.87
LB2	=	Lake Bonney Wind farm Stage 2 output in MW
C5	=	-0.90
LB3	=	Lake Bonney Wind farm Stage 3 output in MW
C6	=	-0.90
Snug	=	Snuggery Power Station output in MW
C7	=	-0.42
SALGEN	=	South Australia's largest single in-service generator in MW (largest potential generation loss under a single credible contingency)
C8	=	-1.33
Const	=	763

Appendix D Fault Levels and Circuit Breaker Ratings

The estimated three-phase and single phase-to-ground fault levels under the 10% POE loading conditions for the South Australian transmission system in 2017-18 are shown in Table D-2. The table also shows the fault level interruption capacity of the lowest rated circuit breaker(s) at each location.

The provided fault level information should be taken only as an approximate guide to the conditions at each location. The results are purely indicative and cannot be used for the purposes of substation design, line design, equipment uprating or any other investment related decision making purposes. Predominantly due to the impact of embedded generation, fault levels may be higher at some locations than shown. Interested parties needing to consider the impacts of their proposals on fault levels should consult ElectraNet and the Distribution Network Service Provider, SA Power Networks, for more detailed information.

Table D-1 gives the network augmentations which were modelled for the future fault level calculations.

Table D-1: Augmentation project list

Commissioning Year	Scope of Work
2015-16	Establish Munno Para substation and install a single 225 MVA 275/66 kV transformer supplying the Northern Suburbs
2015-16	Rebuild Neuroodla substation; install 1 x 10 MVA transformer
2015-16	Upgrade Mount Gunson substation; install 1 x 10 MVA transformer
2016-17	Install a second 25 MVA transformer, rebuild and reconfigure 132 kV bus at Dalrymple Substation
2016-17	Heywood interconnector upgrade with series capacitor banks on the South East-Tailem Bend 275 kV lines and opening of the 132 kV lines

The following assumptions were made when calculating these fault levels:

- Solid fault condition, (i.e. no fault impedance modelled);
- All wind farms are online;
- Embedded generation at Starfish Hill, Angaston, Lonsdale, Port Stanvac and Whyalla is online;
- System normal network configuration: all network elements are in service; and
- TIPS 66 kV busbar sections are coupled.

Table D-2: Circuit breaker fault ratings and system fault levels

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating (kA)	3-phase Fault Level (kA)	1-phase Fault Level (kA)
Angas Creek	132	31.5	4.9	4.6
Angas Creek	33	13.1	5.3	6.6
Ardrossan West	132	21.9	2.7	2.6
Ardrossan West	33	17.5	4.4	3.3
Baroota	132	4.4	3.4	3.1
Baroota	33	17.5	1.6	1.7
Belalie	275	31.5	6.0	3.9
Berri	132	10.9	2.3	2.7
Berri	66	21.9	3.8	4.8
Berri	11	20	10.0	8.5
Back Callington	132	31.5	4.7	4.0
Back Callington	11	25	8.9	0.6
Black Range (Future)	275	40	7.3	3.9
Black Range (Future)	275	40	7.5	3.9
Blanche	132	21.9	5.5	5.6
Blanche	33	17.5	8.4	11.4
Blyth West	275	31.5	5.5	4.9
Brinkworth	275	21	5.3	4.1
Brinkworth	132	15.3	8.0	8.9
Brinkworth	33	17.5	3.0	3.6
Bungama	275	31.5	5.6	4.6
Bungama	132	10.9	7.2	8.2
Bungama	33	13.1	10.6	6.5
Canowie	275	31.5	7.7	4.2
Cherry Gardens	275	31.5	13.2	13.4
Cherry Gardens	132	15.3	7.3	7.8
City West	275	40	14.5	17.9
City West - ACR[32]	66	40	22.5	21.7
City West - South	66	40	19.0	13.7
Clare North	132	40	6.8	6.8
Clare North	33	31.5	9.3	6.9
Cultana	275	31.5	5.8	5.4
Cultana	132	31.5	7.3	7.5
Dalrymple	132	40	2.2	2.2
Dalrymple	33	8	4.0	5.5
Davenport	275	31.5	9.4	10.4
Davenport	132	40	7.8	9.4

32 Adelaide Central Region

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating (kA)	3-phase Fault Level (kA)	1-phase Fault Level (kA)
Davenport	33	31.5	9.6	9.8
Dorrien	132	21.9	7.2	7.4
Dorrien	33	17.5	15.5	10.6
Dry Creek_West	66	21.9	21.0	18.0
Dry Creek_East	66	21.9	20.1	18.6
East Terrace	275	N/A	12.9	13.6
East Terrace	66	31.5	23.8	23.0
Happy Valley	275	31.5	12.8	13.2
Happy Valley	66	21.9	26.1	22.7
Hummocks	132	10.9	4.1	4.1
Hummocks	33	17.5	4.7	4.6
Kadina East	132	40	2.2	2.6
Kadina East	33	17.5	5.7	4.3
Kanmantoo	132	10.9	4.9	4.2
Kanmantoo	33	N/A	1.6	1.7
Kanmantoo	11	13.1	3.8	2.4
Keith	132	15.3	2.2	2.1
Keith	33	31.5	4.0	5.2
Kilburn	275	31.5	15.8	16.4
Kilburn	66	21.9	21.0	18.0
Kincraig	132	15.3	2.6	2.6
Kincraig	33	17.5	4.3	6.0
Le Fevre	275	40	19.9	23.5
Le Fevre	66	25	30.0	27.8
Leigh Creek Coalfield	132	N/A	0.6	0.8
Leigh Creek Coalfield	33	8.7	1.5	2.1
Leigh Creek South	132	N/A	0.6	0.8
Leigh Creek South	33	18.4	0.9	1.3
Magill	275	15.7	14.2	14.9
Magill	66 (1)	21.9	23.7	27.8
Magill	66 (2)	21.9	12.0	8.2
Mannum	132	40	5.1	4.9
Mannum	33	31.5	5.2	4.9
Mannum – Adelaide Pump 1	132	N/A	4.5	4.0
Mannum – Adelaide Pump 1	3.3	N/A	25.3	25.3
Mannum – Adelaide Pump 2	132	N/A	4.7	4.1
Mannum – Adelaide Pump 2	3.3	N/A	25.5	25.5
Mannum – Adelaide Pump 3	132	N/A	4.7	4.0
Mannum – Adelaide Pump 3	3.3	N/A	25.5	25.4

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating (kA)	3-phase Fault Level (kA)	1-phase Fault Level (kA)
Mayurra	132	40	7.4	5.7
Mayurra #1	33	31.5	19.9	12.7
Mayurra #2	33	31.5	16.9	12.0
Middleback	132	40	3.0	2.6
Middleback	33	N/A	1.5	2.1
Millbrook	132	10.9	5.3	4.7
Millbrook	3.3	N/A	17.9	18.2
Mintaro	132	20	8.0	8.2
Mobilong	132	15.3	6.2	6.3
Mobilong	33	31.5	9.2	7.0
Mokota	275	50	6.4	4.2
Monash	132	31.5	2.4	2.9
Monash	66	N/A	3.7	4.8
Morgan – Whyalla Pump 1	132	15.3	4.2	4.1
Morgan – Whyalla Pump 1	3.3	N/A	25.4	25.9
Morgan – Whyalla Pump 2	132	15.3	4.9	4.1
Morgan – Whyalla Pump 2	3.3	N/A	17.9	18.0
Morgan – Whyalla Pump 3	132	15.3	7.9	6.9
Morgan – Whyalla Pump 3	3.3	N/A	18.6	18.9
Morgan – Whyalla Pump 4	132	15.3	9.8	8.4
Morgan – Whyalla Pump 4	3.3	N/A	18.8	19.2
Morphett Vale East	275	31.5	11.8	11.9
Morphett Vale East	66	25	22.0	17.3
Mount Barker	132	31.5	6.8	6.7
Mount Barker	66	31.5	11.3	11.9
Mount Barker South	275	40	11.4	10.6
Mount Barker South	66	66	11.5	11.4
Mount Gambier	132	15.3	6.7	6.6
Mount Gambier	33	17.5	7.1	5.9
Mount Gambier	11 (Cap)	13.1	11.5	9.9
Mount Gunson	132	15.3	1.1	1.1
Mount Gunson	33	N/A	1.3	1.3
Mount Millar	132	40	2.2	1.6
Mount Millar	33	31.5	10.4	1.4
Munno Para	275	40	12.8	11.6
Munno Para	66	40	14.3	10.4
Murray – Hahndorf Pump 1	132	15.3	5.4	5.2
Murray – Hahndorf Pump 1	11	N/A	12.7	13.1
Murray – Hahndorf Pump 2	132	15.3	5.9	5.6

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating (kA)	3-phase Fault Level (kA)	1-phase Fault Level (kA)
Murray – Hahndorf Pump 2	11	N/A	12.9	13.3
Murray – Hahndorf Pump 3	132	15.3	5.7	5.2
Murray – Hahndorf Pump 3	11	N/A	13.0	13.2
Neuroodla	132	N/A	1.5	1.4
Neuroodla	33	8.7	1.4	1.4
New Osborne	66	40	32.1	31.2
North West Bend	132	10.9	4.2	4.4
North West Bend	66	13.1	4.3	4.9
Northfield	275	31.5	15.6	15.8
Northfield	66	31.5	27.8	24.7
Para	275	31.5	18.4	20.5
Para	132	21.9	8.5	9.0
Para	66	21.9	18.8	16.0
Para	11 (SVC)	N/A	30.9	26.7
Parafield Gardens West	275	31.5	16.7	18.1
Parafield Gardens West	66	31.5	18.4	15.3
Pelican Point	275	40	19.6	23.0
Penola West	132	31.5	5.1	5.9
Penola West	33	31.5	5.3	5.0
Pimba	132	31.5	0.9	0.9
Playford	275	10.5	8.9	9.7
Playford	132	10.9	4.7	5.2
Port Lincoln Terminal	132	10.9	2.7	3.0
Port Lincoln Terminal	33	17.5	6.5	5.0
Port Lincoln Terminal	11	13.1	9.0	7.7
Port Pirie	132	40	5.7	6.0
Port Pirie	33	13.1	8.9	5.3
Redhill	132	N/A	6.7	5.5
Robertstown	275	31.5	9.6	7.1
Robertstown	132	31.5	10.8	10.8
Roseworthy	132	31.5	7.3	6.2
Roseworthy	11	25	8.9	12.3
Sleaford	132	40	2.4	1.8
Sleaford	33	31.5	12.4	11.6
Snowtown	132	N/A	4.4	3.1
Snowtown	33	31.5	14.0	1.1
Snuggery	132	10.9	8.4	8.7
Snuggery Industrial (2 x TF in-service)	33	8.7	11.1	13.8

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating (kA)	3-phase Fault Level (kA)	1-phase Fault Level (kA)
Snuggery Industrial (2 x TF in-service)	11 (Cap)	13.1	11.6	10.1
Snuggery (Bus Closed, 3 x TF in-service)	33	31.5	13.3	11.5
Snuggery (Bus Closed, 3 x TF in-service)	11 (Cap)	13.1	12.7	11.0
Sunggery Rural (1 x TF in-service)	33	8.7	3.5	4.6
Snuggery Rural (1 x TF in-service)	11 (Cap)	13.1	5.7	4.9
South East	275	31.5	8.4	8.4
South East	132	20	10.7	11.7
Stony Point	132	31.5	3.8	2.8
Stony Point	11	N/A	9.7	0.3
Tailem Bend	275	21	8.7	6.2
Tailem Bend	132	21.9	7.0	7.9
Tailem Bend	33	25	5.9	7.6
Templers	132	10.9	7.8	7.3
Templers	33	8.7	9.9	7.2
Templers West	275	31.5	8.6	7.4
Templers West	132	40	7.4	7.1
Quarantine 1	66	N/A	14.5	14.1
Quarantine 2	66	N/A	16.7	12.9
Torrens Island	275	31.5	20.9	25.8
Torrens Island	66	40	32.3	31.0
Tungkillo	275	50	12.8	11.0
Waterloo	132	10.9	10.0	8.6
Waterloo	33	13.1	6.1	4.3
Waterloo East	132	N/A	9.8	8.0
Whyalla Central	132	40	6.5	6.7
Whyalla Central	33	40	15.5	8.3
Whyalla Terminal (LMF)	132	10.9	6.2	6.3
Whyalla Terminal (LMF)	33	17.5	4.6	4.6
Wudinna	132	31.5	1.0	1.1
Wudinna	66	21.9	1.5	1.7
Yadnarie	132	10.9	2.6	2.5
Yadnarie	66	40	2.7	3.2
Yadnarie	11 (Reactor)	18.4	6.3	5.4

Appendix E Proposed New Connection Points

In accordance with clause 5.12.2 (c) of the Rules, Table E-1 lists the proposed new connection points.

Table E-1: Proposed new connection point

Connection Point	Planning Region	Planning Year	Connection Voltage (kV)	Scope of Work
Munno Para	Metropolitan	2015	275/66	• Install a single 225 MVA transformer at Munno Para; and • Loop Para - Bungama 275 kV line into Munno Para substation

Appendix F Non-Network Solutions

F1 Background

In accordance with clause 5.12(b).4 of the Rules, ElectraNet considers potential non-network solution options on an equal basis with network options for addressing network limitations or constraints.

F2 Non-Network Solutions Framework

ElectraNet has developed a Non-Network Solution framework to facilitate a timely, efficient, and transparent transmission planning process.

The framework defines ElectraNet's commitment to develop and maintain reliable and cost efficient solutions to network limitations or constraints. The merits of network solutions and non-network solutions, either stand-alone or combined with network solutions, are considered equally.

The framework includes a description of specific actions required to be undertaken in considering a non-network solution option. These begin with the requirement to identify all potentially viable network and non-network options (type, size, location and time of application), and development of a project proposal that includes all these options. For potentially viable non-network options, ElectraNet seeks proposals from non-network solution providers and considers the merits of all proposals received. This includes detailed assessment of technical feasibility, timelines, and efficiency. If a non-network solution option is shown to be the most cost effective technically viable solution then a network support agreement is negotiated with the proponent.

Also included in the framework is a general analysis of the technical applicability and economic feasibility of various types of non-network solutions. It provides a list of the non-network options that may be applicable to ElectraNet's planning process, for example:

- Existing embedded generation;
- New embedded generation; and
- Demand response;

and includes a description of each of these options. This comprises details regarding:

- Customer classes involved (residential, commercial, industrial etc.);
- Technical/operational considerations;
- Advantages;
- Challenges and potential issues; and
- Typical cost structure, if available.

F3 Non-Network Solutions Planning Assessment

Non-network options are assessed according to the following criteria:

- Ability to provide a level of net demand reduction that will resolve the identified limitation;
- Ability to operate to reduce the level of net demand on the limited asset(s) at appropriate times (for example, above 90% of the asset's 10% POE demand level);
- Ability to be provided at the lowest Net Present Value (NPV) cost; and
- Ability to provide reliable demand reduction.

Any options which have a high risk of not being delivered in time to meet the required demand reduction are excluded. The remaining options are ranked by cost from least to the most expensive in terms of $/MW (using NPV cost).

The implementation of these options can be based on the application of either a single option, or simultaneous application of two or more options. In the latter case, priority is given to the lower $/MW option (NPV cost), where other considerations are equal.

A non-network solution is deemed economically feasible if the NPV cost of demand reduction (single or combined) is less than the NPV of the alternative network solution. In the case of a market benefit-driven project, the option must also yield a positive net market benefit. For projects that require application of the RIT-T, the option must satisfy the RIT-T as the preferred option.

F4 Implementation of Non-Network Solutions

The implementation process for a non-network solution requires the following steps:

- Development of non-network solution requirements:
    - Years of potential implementation, including preparation year, based on load forecast);
    - Trigger event (e.g. temperature above 40 ˚C);
    - Type and size of load to be managed;
    - Load curve at the connection point; and
    - Time of the day, time within year(season), total time duration of the implementation for each year(total number of hours);
- Initial determination of implementation cost for each year; and
- Economic assessment to determine whether the solution should be implemented.

If the solution is to be implemented, the following steps are then required:

- Negotiation of a Network Support Agreement;
- Detailed design of the interfaces between ElectraNet and the non-network solution provider; and
- Final implementation of the non-network solution.

The cost of implementing a non-network solution can vary broadly, and is subject to any specific implementation issues and requirements.

It depends on the non-network solution type (load and/or generator), size, geographical location, connection point voltage level, duration of service requirement, and the commercial requirements of the non-network solution provider.

F5 Example of Non-Network Solution Assessment Costs

While developing the Project Assessment Draft Report for the Lower Eyre Peninsula Reinforcement Project, ElectraNet engaged a non-network solution provider to assess the potential for using demand response to defer the network investment. Costs used in this assessment were:

- Customer demand reduction costs $150,000 - $200,000 per MW; and
- Generator support costs of $200,000 - $400,000 per MW.

These figures yielded optimal annual cost estimates for a three year demand reduction program as shown in Table F-1, in 2011-12 dollars.

Table F-1: Optimal annual costs for three year demand reduction program (2011-12 dollars)

	2016-17	2017-18	2018-19	2019-20
Demand reduction (MW)	0[33]	1.5	3.6	5.7
Annual Cost	$200,000	$270,000	$648,000	$1,026,000

F6 Constraints Currently Being Considered for Non-Network Solutions

ElectraNet has actively considered a non-network solution option that was proposed in response to the Baroota Substation Upgrade PSCR, which closed for submissions on 8 August 2014. ElectraNet intends to publish the PADR for this project in mid-2015. Refer to section 7.6.1 for more details regarding this project.

[33] Preparation for the first year of demand reduction program.

Appendix G Additional Transmission Planning Information

G1 South Australian Electricity Market Framework

G1.1 Australian Energy Market Operator

AEMO has the responsibility of National Transmission Planner conferred on it under the National Electricity Law. The South Australian Energy Minister has also requested AEMO perform certain additional functions in the South Australian jurisdiction.

Among other things, AEMO is required to provide information regarding the South Australian power system that includes:

- Assessments of the performance of connection point between transmission and distribution systems;
- Any areas of current or future congestion on the transmission network;
- Generation dispatch scenarios;
- Historical fuel use for electricity generation and an assessment of fuel availability to support future electricity production;
- Estimated greenhouse gas emissions associated with electricity supply options;
- Existing and potential future electricity supply options;
- The forecast balance between supply and demand and whether that balance falls within the national guidelines for reliability; and
- The historical and forecast future demand for electricity based on both seasonal peak usage and aggregate energy usage.

Until 2012, AEMO provided the above information in the South Australian Supply and Demand Outlook. Since 2012, a collection of advisory reports for South Australia have been released over the course of each year (available on AEMO's South Australian Advisory Functions webpage), and in the NTNDP which is published annually in December.

G1.2 Essential Services Commission of South Australia

ESCOSA was established under the Essential Services Commission Act 2002 with the objective of "protection of the long term interests of South Australian consumers with respect to the price, quality and reliability of essential services". ESCOSA is required to have regard to:

- The promotion of competitive and fair market conduct;
- The prevention of misuse of monopoly or market power;
- The facilitation of entry into relevant markets;
- The promotion of economic efficiency;
- The benefit consumers gain from competition and efficiency;
- The financial viability of regulated industries and the incentive for long term investment; and
- The promotion of consistency in regulation with other jurisdictions[34].

[34] Essential Services Commission Act 2002 - Part 2 6(a) and (b)

ESCOSA's principal functions and powers in relation to the electricity supply industry include:

- Making determinations for standing contract prices;
- Administering the licensing regime for electricity entities (generation, transmission, distribution, retail and system control);
- Monitoring the performance of licensed entities and promote improvement in standards and conditions of service and supply;
- Formulating and review from time to time the industry codes (such as the ETC);
- Enforcing compliance with Licensees' Regulatory obligations, including undertaking enforcement action as appropriate; and
- Providing advice to the SA Energy Minister on matters relating to the economic regulation of regulated industries, including reliability issues and service standards; these functions include setting reliability standards for South Australian transmission system and connection points, as set out in the ETC.

G1.3 National Electricity Rules

The Rules prescribe a TNSP's obligations with regard to network connection, network planning, network pricing and establishing or making modifications to connection points. In addition, the Rules detail the technical obligations that apply to all Registered Participants.

ElectraNet must plan and operate its transmission network in accordance with the mandated reliability and security standards set out in the Rules.

Clause S5.1.2.1, 'Credible contingency events', of the Rules sets out the following mandatory requirements on TNSPs:

"Network Service Providers must plan, maintain and operate their transmission and distribution networks to allow the transfer of power from generating units to Customers with all facilities or equipment associated with the power system in service and may be required by a Registered Participant under a connection agreement to continue to allow the transfer of power with certain facilities or plant associated with the power system out of service, whether or not accompanied by the occurrence of certain faults (called "credible contingency events")."

In practical terms, this obligation requires the non-radial portions of the power system to be planned with a system normal network (N) being able to withstand a single credible contingency (N-1) without compromising the integrity of the network.

Chapter 4 of the Rules outlines system security requirements. That chapter requires that even during planned outages, the transmission system must have sufficient redundancy or, if this is not inherent in the network, automatic control systems in place to return the network to a secure operating state following a credible contingency event.

The Rules are available at the following link:

http://www.aemc.gov.au/rules.php

At the time of publication the current version of the Rules was Version 69.

G2 ElectraNet Planning Framework

G2.1 Planning Assumptions

AEMO's National Transmission Plan, forecast demand and generation, together with existing network capability and connection arrangements with customers form the base assumptions for transmission planning in South Australia. The limitations identified on the transmission network are driven by the need to meet the technical requirements of the Rules and ETC which is aimed to meet customer demand in a secure and reliable manner, while not violating the limitations as described in the following sections.

G2.2 Technical Criteria

G2.2.1 Overhead Line Ratings

ElectraNet applies transmission line ratings determined to ensure statutory conductor to ground clearances is maintained at all times. As the rating of overhead lines is dependent upon environment conditions, ElectraNet uses ambient temperature dependent ratings which are generally translated as three seasonal ratings (Summer, Spring/Autumn and Winter).

In the planning context, to assess summer maximum demand periods, the summer rating is normally applied. The spring/autumn rating is applied for assessment of average load conditions, while the winter rating is applied for light loading conditions.

G2.2.2 Transformer Ratings

ElectraNet applies ratings to transformers in accordance with Australian Standards. Where specifications of the transformers do not allow cyclic ratings, nameplate ratings are applied.

However, in cases where the original specification or subsequent assessment allows, transformers are given a cyclic rating above nameplate in accord with Australian Standard AS 60076.7-2013.

For the purposes of planning, the following criteria are adopted:

- The normal cyclic rating is used to determine the maximum allowable loading under system normal or planned outage operating conditions.
- The emergency cyclic rating is used to determine the maximum allowable loading under single or multiple contingency conditions.

As described in section 5.5, ElectraNet applies short term ratings to transformers where it is technically viable to do so and where it will release additional transmission capacity and reduce the occurrence of network and interconnection constraints. These ratings take the form of a Short Term Emergency Loading, which can be sustained for up to 30 minutes, and a Long Term Emergency Loading, which can be sustained for up to 3 hours.

G2.2.3 Cable Ratings

Underground cable ratings are evaluated on the basis of temperature limits determined by the type of insulation used, method of installation, load-cycle shape, and the presence of other loaded cables nearby. Calculations are undertaken in accordance with IEC 60287 (International Electrotechnical Commission Standard).

Unless otherwise individually specified, only those cables operating below 66 kV are assigned emergency ratings. This is due to the high costs associated with 66 kV and above cables, the soil conditions the cables are exposed to (for example in the vicinity of Torrens Island) and the potential impacts that a prolonged outage of such a cable could have on customer supply.

G2.2.4 Managing Fault Levels

For safety reasons, transmission system fault levels should not exceed the fault rating of the bus or any equipment in that part of the system at any time for any plausible network configuration. It is also important that the fault level at a substation does not exceed the fault rating of the earth grid to prevent excessive earth potential rise.

To mitigate fault level issues, due consideration is given to installing high impedance transformers, installing series reactors, saturable reactors and bus section reactors to limit balanced and unbalanced faults, and installing neutral earthing resistors or reactors on connection point transformers to limit unbalanced phase to ground fault currents. Additionally, due consideration is given to network reconfiguration as a means of reducing fault levels (such as splitting busses or by-passing substation diameters). Such reconfiguration is only done where there is no significant impact on transfer capacity, network reliability, security or operability.

G2.2.5 Reactive Power Reserve Margins

As per schedule S5.1.8 of the Rules, ElectraNet assesses reactive power margin at connection points in accordance with the following provision:

> The *voltage* control criterion is that stable *voltage* control must be maintained following the most severe *credible contingency event*. This requires that an adequate *reactive power* margin must be maintained at every *connection point* in a *network* with respect to the *voltage* stability limit as determined from the *voltage*/reactive *load* characteristic at that *connection point*. Selection of the appropriate margin at each *connection point* is at the discretion of the relevant *Network Service Provider*, subject only to the requirement that the margin (expressed as a capacitive *reactive power* (in Mvar)) must not be less than one per cent of the maximum fault level (in MVA) at the *connection point*.

ElectraNet interprets and applies the Rules requirement for reactive power reserve margin planning in the following manner:

1. The “maximum fault level (in MVA) at the connection point” is deemed to be the maximum three-phase fault level that is reasonably expected. This includes the effect of local and embedded conventional generation, but with wind farm generator output set to zero.
2. The minimum required reactive power reserve margin (in Mvar) at each connection point is calculated as 1% of the fault level (in MVA) determined above.

3. The "voltage/reactive load characteristic" at a connection point is a series of curves produced by reactive power versus voltage (Q-V) analysis for system normal and all relevant single credible contingencies. It indicates a bus's reactive power demand (inductive or capacitive) across a range of voltage levels. When doing Q-V analyses, ElectraNet uses the forecast 10% POE load level, with regional diversity factors applied. Wind farm installations local to the region of the system being studied are disconnected. The Q-V analysis is carried out for all relevant credible contingencies.

4. From the curve produced by Q-V analysis, the "most severe credible contingency event" is identified. It can be recognised as the credible contingency associated with the Q-V curve that has the highest minimum value of reactive power demand across the investigated voltage range. For the purpose of Q-V analysis, this credible contingency is identified as the "critical contingency".

5. The reactive power reserve margin is equal to the negative of the minimum reactive power demand for the critical contingency. For example, if the minimum reactive power demand is -10 Mvar (i.e. the bus must absorb 10 Mvar to hold the voltage level associated with the minimum of the relevant Q-V curve), then the actual reactive power reserve margin at that bus is 10 Mvar. The reactive power reserve margin is an indicator of the voltage stability of the network following the critical contingency: the smaller the reactive power reserve margin, the closer the network will be to voltage collapse, following the studied critical contingency.

6. The actual reactive power reserve margin is compared to the minimum required value that was determined in step 2. If the actual margin is less than the minimum required value, a solution is required to resolve the identified breach.

G2.2.6 Stability Criteria

The following stability criteria are applied to ensure stable power system performance during and immediately after a system disturbance and before equilibrium conditions are achieved.

Following the application of a single credible contingency (as defined in clause S5.1a.3 of the Rules):

- The transmission system will remain in synchronism (transient stability);
- Damping of the system oscillations will be adequate (small signal stability);
- Network voltage criteria will be satisfied (voltage stability); and
- System frequency will remain within defined operating limits (frequency stability).

When one of these stability criteria is forecast to be violated, some form of planning action is initiated – either system augmentation works, load management measures, control schemes (e.g. under-frequency, under-voltage load shedding, revised constraint equations or other power flow limiting strategies) or plant control system modifications.

For lines at any voltage above 66 kV which are not adequately protected by an overhead earth wire and/or lines with footing resistances in excess of 10 Ohms, the credible contingency may be extended to include a single circuit three-phase solid fault to cover the increased risk of such a fault occurring.

Appendix H Future Transmission Annual Planning Reports

The significant incremental improvements contained within this report include:

- Provision of generation connection headroom per connection point (assuming system normal conditions) in section 6.1;
- The introduction of scenario based planning, reported in section 7.4 to section 7.9, to provide potential future developments over a range of potential futures;
- The addition of future network congestion on the South Australian electricity transmission system in section 3.5;
- The publication of a detailed SA Connection Point Demand Forecast Report in February 2015, that complements and expands on the demand forecast information presented in section 4.1; and
- The addition of Appendix F to better inform stakeholders of ElectraNet's approach to non-network solutions, including an example of indicative costs and a list of projects for which ElectraNet is actively assessing the viability of potential non-network solutions.

These initiatives are intended to be further refined and carried forward into future Transmission Annual Planning Reports.

Another initiative that ElectraNet will address in 2016 is to expand on alternative options for projects that are driven by replacement and refurbishment needs.

Please direct any suggestions for improvements to future Transmission Annual Planning Reports to:

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Appendix I Compliance Checklist

This section sets out a compliance checklist which demonstrates the compliance of ElectraNet's 2015 Transmission Annual Planning Report with the requirements of clause 5.12.2(c) of version 69 of the Rules.

Table I-1: Transmission Annual Planning Report compliance checklist

Summary of Requirements	Section
The Transmission Annual Planning Report must set out:	
(1) the forecast loads submitted by a Distribution Network Service Provider in accordance with clause 5.11.1 or as modified in accordance with clause 5.11.1(d);	Chapter 4
(2) planning proposals for future connection points;	Appendix E
(3) a forecast of constraints and inability to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction over 1, 3 and 5 years;	Section 7.9
(4) in respect of information required by subparagraph (3), where an estimated reduction in forecast load would defer a forecast constraint for a period of 12 months, include: (i) the year and months in which a constraint is forecast to occur; (ii) the relevant connection points at which the estimated reduction in forecast load may occur; (iii) the estimated reduction in forecast load in MW needed; and (iv) a statement of whether the Transmission Network Service Provider plans to issue a request for proposals for augmentation or a non-network option identified by the annual planning review conducted under clause 5.12.1(b) and if so, the expected date the request will be issued;	Section 7.6.1
(5) for all proposed augmentations to the network the following information, in sufficient detail relative to the size or significance of the project and the proposed operational date of the project: (i) project/asset name and the month and year in which it is proposed that the asset will become operational; (ii) the reason for the actual or potential constraint, if any, or inability, if any, to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction, including load forecasts and all assumptions used; (iii) the proposed solution to the constraint or inability to meet the network performance requirements identified in subparagraph (ii), if any; (iv) total cost of the proposed solution; (v) whether the proposed solution will have a material inter-network impact. In assessing whether an augmentation to the network will have a material inter-network impact a Transmission Network Service Provider must have regard to the objective set of criteria published by AEMO in accordance with clause 5.21 (if any such criteria have been published by AEMO); and (vi) other reasonable network options and non-network options considered to address the actual or potential constraint or inability to meet the network performance requirements identified in subparagraph (ii), if any. Other reasonable network and non-network options include, but are not limited to, interconnectors, generation options, demand side options, market network service options and options involving other transmission and distribution networks;	Section 7.6 Section 7.7 Section 7.8 Section 7.9

Summary of Requirements	Section
(6) the manner in which the proposed augmentations relate to the most recent NTNDP and the development strategies for current or potential national transmission flow paths that are specified in that NTNDP;	Chapter 3
(7) for all proposed replacement transmission network assets: (i) a brief description of the new replacement transmission network asset project, including location; (ii) the date from which the Transmission Network Service Provider proposes that the proposed new replacement transmission network asset will become operational; (iii) the purpose of the proposed new replacement transmission network asset; (iv) a list of any reasonable network options or non-network options to the proposed new replacement transmission network asset which are being, or have been, considered by the Transmission Network Service Provider (if any). Those alternatives include, but are not limited to, interconnectors, generation options, demand side options, market network service options and options involving other transmission or distribution networks; and (v) the Transmission Network Service Provider's estimated total capitalised expenditure on the proposed new replacement transmission network asset; and	Section 7.9
(8) any information required to be included in an Transmission Annual Planning Report under clause 5.16.3(c) in relation to a network investment which is determined to be required to address an urgent and unforeseen network issue	Not Applicable