SOUTH AUSTRALIAN TRANSMISSION ANNUAL PLANNING REPORT

June 2017

ElectraNet

Copyright and Disclaimer

Contents

EXECUTIVE SUMMARY **9**

1. INTRODUCTION **11**

1.1 ElectraNet's role in supplying electricity 11
1.2 Network planning approach and reporting 12
1.3 Transmission planning responsibilities and rule requirements 12
1.4 Feedback on this report 14

2. THE SOUTH AUSTRALIAN TRANSMISSION SYSTEM **15**

2.1 Overview 15
2.2 Renewable energy generation 17
2.3 Range of South Australian demands 18
2.4 Interconnector transfer capacity 19

3. A SYSTEM IN TRANSITION **20**

3.1 South Australian context 20
3.2 Recent significant events on the South Australian transmission system 22
3.3 Current reviews and inquiries 22
3.4 South Australian Government measures 23
3.5 ElectraNet initiatives 23
3.5.1 South Australian Energy Transformation RIT-T 23
3.5.2 Grid connected battery storage 25
3.5.3 System Strength 26
3.5.4 Northern SA Voltage Control 27
3.5.5 Frequency control following separation of South Australia from the NEM 27

4. NATIONAL TRANSMISSION NETWORK DEVELOPMENTS AND REVIEW OF SOUTH AUSTRALIAN NETWORK CONSTRAINTS **28**

4.1 Network limitations identified in the NTNDP 29
4.2 Transmission network constraints 30
4.3 Network market benefit projects 35
4.4 Future network congestion 38

5. SUMMER (2016-17) DEMAND REVIEW AND FORECASTS **40**

5.1 Summer demand review 40
5.1.1 Connection point review 43
5.2 Demand forecast 44
5.2.1 Review of 2016 National Electricity Forecasting Report 44
5.2.2 Connection point forecasts 45

6. CONNECTION OPPORTUNITIES **46**

6.1 Connection opportunities for generators 46

6.2 CONNECTION POINT OPPORTUNITIES FOR CUSTOMERS 48
6.3 SUMMARY OF CONNECTION OPPORTUNITIES 49
6.4 PROPOSED NEW CONNECTION POINTS 52
6.5 CURRENT AND POTENTIAL TRANSMISSION CONNECTION HUBS 52

7. COMPLETED, COMMITTED AND PENDING PROJECTS 54
7.1 RECENTLY COMPLETED PROJECTS 54
7.2 COMMITTED PROJECTS 55
7.2.1 Tailem Bend substation upgrade 56
7.3 PENDING PROJECTS 56

8. TRANSMISSION NETWORK DEVELOPMENT PLAN 57
8.1 PLANNING SCENARIO AND SENSITIVITIES 57
8.2 SUMMARY OF PLANNING OUTCOMES 59
8.3 EMERGING SYSTEM ISSUES 59
8.3.1 Install a grid-connected battery at Dalrymple (ESCRI-SA) 60
8.3.2 New high capacity interconnector 61
8.3.3 Install synchronous condensers 63
8.4 CONNECTION POINTS 64
8.4.1 Replace Eyre Peninsula 132 kV transmission lines 65
8.4.2 Establish a new connection point at Gawler East 67
8.5 MARKET BENEFIT OPPORTUNITIES 68
8.5.1 Uprate Riverland 132 kV lines 68
8.5.2 Uprate the Waterloo East to Robertstown 132 kV line 70
8.5.3 Apply dynamic ratings to transmission lines between South East and Tungkillo 70
8.5.4 Remove plant rating limits from the Robertstown to Davenport 275 kV lines 71
8.5.5 Install an additional 100 Mvar 275 kV capacitor bank at South East 71
8.5.6 Trial modular power flow control elements to relieve congestion 72
8.5.7 Improve Robertstown circuit breaker arrangement 72
8.5.8 Connect the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo 73
8.5.9 Apply short term overload ratings to the Robertstown 275/132 kV transformers 73
8.6 MAXIMUM DEMAND 74
8.6.1 Upper North region eastern 132 kV line reinforcement 74
8.6.2 Upper North region western 132 kV line reinforcement 75
8.7 MINIMUM DEMAND 76
8.7.1 Install a 50 Mvar 275 kV switched reactor at Templers West 76
8.7.2 Install a 50 Mvar 275 kV switched reactor at Blyth West 78
8.7.3 Install a second 50 Mvar 275 kV switched reactor at Para 78
8.7.4 Install an additional 50 Mvar 275 kV switched reactor in the Mid North 79
8.8 MAXIMUM FAULT LEVELS 79
8.9 EMERGENCY CONTROL SCHEMES 80
8.9.1 Implement a coordinated Over Frequency Generation Shedding scheme 81
8.9.2 Protect against system islanding for the non-credible loss of multiple generators 81

APPENDICES 83

APPENDIX A TRANSMISSION PLANNING FRAMEWORK 84

A1 SOUTH AUSTRALIAN ELECTRICITY MARKET FRAMEWORK 84
A1.1 Australian Energy Market Operator (AEMO) 84
A1.2 Essential Services Commission of South Australia (ESCOSA) 84
A1.3 National Electricity Rules 85
A2 ELECTRANET'S RESPONSIBILITIES UNDER THE RULES 86
A2.1 Transmission annual planning report 86
A2.2 Regulatory Investment test for transmission (RIT-T) 87
A3 ELECTRANET'S RESPONSIBILITIES UNDER THE ELECTRICITY TRANSMISSION CODE (ETC) 88

APPENDIX B COMPLIANCE CHECKLIST 90

APPENDIX C REGIONAL NETWORKS 93
C1 METROPOLITAN REGION 93
C2 EASTERN HILLS REGION 94
C3 MID NORTH REGION 95
C4 RIVERLAND REGION 96
C5 SOUTH EAST REGION 97
C6 EYRE PENINSULA REGION 98
C7 UPPER NORTH REGION 99

APPENDIX D INTER-REGIONAL TRANSFER CAPACITY 100
D1 HEYWOOD INTERCONNECTOR 100
D1.1 Import and export capability 100
D1.2 Heywood interconnector transfer limit equations 101
D2 MURRAYLINK INTERCONNECTOR 104
D2.1 Import capability 104
D2.2 Export capability 104

APPENDIX E FAULT LEVELS AND CIRCUIT BREAKER RATINGS 105

APPENDIX F NETWORK SUPPORT SOLUTIONS 112
F1 NETWORK SUPPORT SOLUTIONS FRAMEWORK 112
F2 NETWORK SUPPORT SOLUTIONS PLANNING ASSESSMENT 112
F3 PROJECTS FOR POTENTIAL NETWORK SUPPORT SOLUTIONS 113

APPENDIX G COMMITTED, PENDING, PROPOSED AND POTENTIAL PROJECTS 114
G1 SUMMARY OF COMMITTED, PENDING, PROPOSED AND POTENTIAL AUGMENTATION PROJECTS 115
G2 SUMMARY OF COMMITTED, PENDING AND PROPOSED SECURITY AND COMPLIANCE PROJECTS 118
G3 SUMMARY OF COMMITTED, PENDING AND PROPOSED ASSET REPLACEMENT PROJECTS 122
G4 SUMMARY OF CONTINGENT PROJECTS 129

ABBREVIATIONS 131

GLOSSARY OF TERMS 133

Figures

Figure 1-1: Role of ElectraNet in the electricity supply chain 11

Figure 2-1: South Australia’s transmission system 15

Figure 2-2: The Main 275 kV Grid including interconnectors 16

Figure 2-3: Maximum, average, and minimum electricity demands on the SA transmission network for the past six years 18

Figure 2-4: South Australian system wide load duration curves for 2009-10 and 2016-17 (to 8 June)..19

Figure 3-1: Energy generation patterns have changed significantly in recent years 21

Figure 3-2: Renewable energy from wind and solar rooftop PV systems has increased significantly over the last five years 21

Figure 3-3: Potential new interconnector options 24

Figure 3-4: Proposed Dalrymple connection site for a 30 MW, 8 MWh battery energy storage system 25

Figure 5-1: Daily temperature index for summer 2016-17 42

Figure 5-2: AEMO's 2016 NEFR neutral growth forecasts..45

Figure 6-1: Current and possible South Australian future transmission connection hubs 53

Figure 8-1: Assumptions and sensitivities considered in ElectraNet’s planning process, including potential future step load increases, generator retirements, and renewable generator connections 58

Figure 8-2: Proposed projects to address emerging challenges to the secure and stable operation of the power system...60

Figure 8-3: Connection point projects..65

Figure 8-4: Committed and proposed market benefit projects 69

Figure 8-5: Projects that may be required if potential spot loads connect....................................75

Figure 8-6: Projects that are proposed to manage the impact of declining minimum demand 77

Figure A-1: ElectraNet's approach to the Regulatory Investment Test for Transmission (RIT-T) process ……………………………………………………………………………………..88

Figure C-1: Metropolitan transmission network and supply region…………………………………93

Figure C-2: Eastern Hills transmission network and supply region ……………………………......94

Figure C-3: Mid North transmission network and supply region ……………………………………95

Figure C-4: Riverland transmission network and supply region ……………………………………96

Figure C-5: South East transmission network and supply region …………………………………..97

Figure C-6: Eyre Peninsula transmission network and supply region ………………………………98

Figure C-7: Upper North transmission network and supply region …………………………………99

Tables

Table 1: High level summary of planning outcomes 10

Table 4-1: Potential economic dispatch limitations identified in the 2016 NTNDP 29

Table 4-2: Constraint equations, descriptions and ranking 31

Table 4-3: Potential inter-regional market benefit projects...36

Table 4-4: Potential intra-regional market benefit projects...37

Table 4-5: Forecast South Australian transmission network congestion.......................................38

Table 5-1: 2016-17 summer temperature data compared with long term trends...........................41

Table 5-2: Highest demand periods in summer 2016-17 41

Table 5-3: Recorded demands more than 100% of 10% POE demand forecast in summer 2016-17 43

Table 5-4: Recorded demands less than 85% of 10% POE demand forecast in summer 2016-17 43

Table 6-1: System conditions considered in the assessment of the ability of the South Australian transmission system to accommodate additional generation..47

Table 6-2: Indication of available capacity to connect generation and load in 2018-19.................50

Table 6-3: Proposed new connection points for generators and customers 52

Table 7-1: Projects completed between 1 May 2016 and 31 May 2017.......................................54

Table 7-2: Committed projects 55

Table 8-1: Characteristics and assumptions of ElectraNet's planning scenario 57

Table 8-2: Summary of planning outcomes..59

Table 8-3: Options considered for a new high capacity interconnector...62

Table 8-4: Options considered for Eyre Peninsula 132 kV line replacement 66

Table 8-5: Options considered for a new Gawler East connection point......................................68

Table A-1: Summary of ETC redundancy requirements …………………………………………..…89

Table B-1: Compliance Checklist ……………………………………..……………………………90

Table E-1: Circuit breaker ratings and system fault levels ……………………………………………105

Table F-1: Planned projects for which ElectraNet seeks or has sought proposal for network support solutions 113

Table G-1: Committed, pending and proposed and potential augmentation projects..................115

Table G-2: Committed pending and proposed security and compliance projects ………………..118

Table G-3: Committed, pending and proposed asset replacement projects ……………………..122

Table G-4: Contingent projects ……………………………………………………………………..129

Executive Summary

South Australia's transmission network plays a major role in the State's electricity supply, in an environment of unprecedented change.

South Australia is at the forefront of energy transformation with world-leading levels of intermittent renewable energy compared to demand.

In 2016-17, a number of significant events impacted the supply of electricity to large numbers of South Australian customers, including a state-wide system black event in September 2016. These events have highlighted the importance of system security and reliability as we transition to a lower carbon emissions future.

On 9 June 2017, the Independent Review into the Future Security of the National Electricity Market (the Finkel Review) released its final report and blueprint designed to ensure the optimal functioning of Australia's electricity system in the future[1].

Within this context, ElectraNet's annual planning process has sought to pre-empt network obstacles or opportunities, and ensure plans are in place to accommodate them.

This South Australian Transmission Annual Planning Report summarises the outcomes of this planning process, including information on the current capacity, connection opportunities, and emerging limitations of South Australia's electricity transmission network. It covers a ten-year planning period and describes the current network, demand projections, emerging network limitations or constraints, and information on completed, committed, pending and proposed transmission network developments.

This report includes ElectraNet's response to the emerging challenges facing South Australia's electricity transmission network. This includes initiatives for conducting a Regulatory Investment Test for Transmission (RIT-T) to investigate the technical and economic feasibility of a new transmission interconnector between South Australia and the Eastern States and non-network alternatives, pursuing a grid-scale battery energy storage project to support higher levels of intermittent renewable energy, and working with the Australian Energy Market Operator (AEMO) to address the changing requirements for system strength and frequency control to manage system security.

Our network planning considers a wide range of potential future scenarios and developments.

This report is designed to inform stakeholders and help potential users of electricity and generators to identify and assess opportunities in the NEM. It also helps AEMO to prepare the National Transmission Network Development Plan, which outlines the strategic and long-term development of the national transmission system under a range of market development scenarios.

In March 2017, ElectraNet submitted a Revenue Proposal to the Australian Energy Regulator (AER) for the 2018-19 to 2022-23 period that addresses future network investment requirements.[2] These requirements are consistent with the key planning outcomes in this report, as summarised in Table 1.

1 The Finkel Review's Final Report is available at http://www.environment.gov.au/energy/publications/ electricity-market-final-report.

2 Our Revenue Proposal is available on aer.gov.au. Other documents referenced are available on electranet.com.au.

Table 1: High level summary of planning outcomes

Planning focus	Key outcomes
Emerging system security issues (e.g. system inertia, system strength)	System security issues that may arise from low levels of system inertia and declining levels of system strength (as projected in AEMO's 2016 National Transmission Network Development Plan) could be addressed by: • establishing a new interconnector between South Australia and the Eastern States to address emerging system security issues and provide net market benefits, as is being considered by the South Australian Energy Transformation RIT-T • installing plant such as synchronous condensers A grid-scale battery energy storage system is proposed for connection at Dalrymple, to help improve system security and reliability.
Connection points	The existing network support arrangement at Port Lincoln expires in December 2018. A RIT-T has been commenced to determine the most cost effective way of continuing to meet the required reliability standard at Port Lincoln beyond that date. The outcome of this investigation could be investment in new transmission lines on the Eyre Peninsula (e.g. a new double circuit line from Cultana to Yadnarie to Port Lincoln) and/ or a new network support arrangement.
Market benefit opportunities	A range of market benefit driven projects is proposed to reduce the impact of network constraints and increase the capability of the transmission network, providing net market benefits.
Maximum demand	South Australia's transmission network is projected to be adequate to support forecast maximum demand for the duration of the planning period. Augmentation may be needed to supply future significant individual load connections, particularly in the Upper North region, depending on their size and location.
Minimum demand	As the minimum demand supplied by the transmission network is forecast to decrease, a series of 275 kV reactor investments (or similar) is needed to prevent voltage levels from exceeding equipment ratings if an unplanned contingency event was to occur at times of low demand.
Maximum fault levels	Fault levels are forecast to remain within design and equipment limits for the duration of the planning period.
Emergency control schemes	ElectraNet and AEMO are working together to develop a special protection scheme that will reduce the chance of islanding following a non-credible simultaneous loss of multiple generators within South Australia.

We invite feedback on any aspect of this report, from our demand projections and emerging network limitations to proposed solutions, the planning scenarios considered and the presentation of information in this report. Your feedback will help us to serve you better and ensure we can provide a reliable and high quality electricity supply to customers at the lowest long-run cost.

Comments and suggestions can be directed to:

Hugo Klingenberg, Senior Manager Network Development, consultation@electranet.com.au.

1. Introduction

ElectraNet specialises in electricity transmission, providing energy and infrastructure solutions across Australia. We power people's lives by delivering safe, affordable and reliable solutions to power homes, businesses and, ultimately, the economy.

Our business includes South Australia's regulated transmission network. ElectraNet plans, builds, operates, maintains and owns the State's high voltage electricity transmission network and is the principal Transmission Network Service Provider (TNSP) in South Australia.

1.1 ElectraNet's role in supplying electricity

South Australia's electricity transmission network is the backbone of the electricity supply system.

Our network transports power generated from local and interstate sources over long distances to metropolitan and regional areas of demand (load centres).

It is one of the most extensive regional transmission systems in Australia, extending across some 200,000 square kilometres of the State. This network consists mainly of transmission lines operating at 132,000 and 275,000 Volts.

ElectraNet's direct customers include power generators, the State's electricity distributor SA Power Networks, and large industry (Figure 1-1). The services we provide also impact the cost and reliability of electricity for customers connected to SA Power Networks' distribution network.

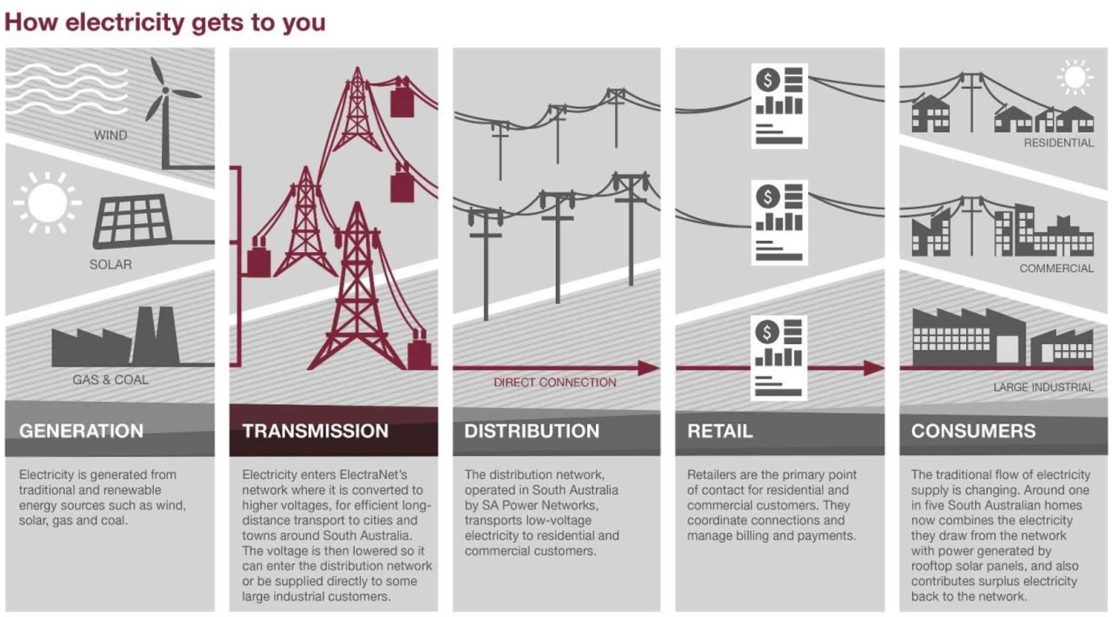

Figure 1-1: Role of ElectraNet in the electricity supply chain

1.2 Network planning approach and reporting

Each year, ElectraNet reviews the capability of its transmission network and regulated connection points to meet ongoing electricity demand, forecast under a variety of operating scenarios. ElectraNet works with SA Power Networks, which is responsible for distributing electricity throughout South Australia, to complete the review. ElectraNet's planning and forecasting processes align with the applicable regulatory requirements (Appendix A).

This report presents the outcomes of the annual planning review and forecasting to help you understand the network's current capacity and how we think this may change in the future. The report covers a 10-year planning period (1 July 2017 to 30 June 2027) and identifies potential network capability limitations and possible solution options.

The report provides information on:

- existing transmission network performance and power transfer capability (Chapter 2)
- emerging challenges (Chapter 3)
- developments in the national transmission network and constraints that impact South Australia (Chapter 4)
- demand forecast for the next 10-year period (Chapter 5)
- connection opportunities (Chapter 6)
- transmission network development plans, including recently completed, committed, and planned projects (Chapter 7).

The report does not define a single specific future development plan for the South Australian transmission system, rather it is intended to form part of a consultation process to ensure efficient and economical development of the transmission network can meet forecast electricity demand over the planning period. Decisions to invest in the South Australian transmission system will only be made at the time they become needed.

1.3 Transmission planning responsibilities and rule requirements

ElectraNet is the principal TNSP and the jurisdictional planning body for South Australia under clause 11.28.2 of the National Electricity Rules (Rules). As such, ElectraNet has specific obligations (Chapter 5 of the Rules) 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 complies with the South Australian Electricity Transmission Code (ETC) that sets out reliability planning standards for each connection point on the transmission network.

As part of its planning and development responsibilities, ElectraNet must:

- consider public and worker safety paramount when planning, designing, constructing, operating and maintaining the network
- operate the network with sufficient capability to provide the minimum level of transmission network services required by customers

- comply with the technical and reliability standards contained in the Rules and jurisdictional instruments such as the ETC
- plan, develop and operate the network so there is no need to shed load under normal and foreseeable operating conditions to achieve the quality and reliability standards within the Rules
- conduct joint planning with distribution network service providers (DNSPs) and other TNSPs whose networks can impact the South Australian transmission network. That includes SA Power Networks, APA (Murraylink operator and part-owner) and the Australian Energy Market Operator (AEMO, in their role as Victorian transmission network planner). We also participate in inter-regional system tests associated with new or augmented interconnections
- provide information to registered participants and interested parties on projected network limitations and the required timeframes for action
- develop 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 that may have a material inter-network impact.

ElectraNet's annual planning review analyses the expected future capability of the South Australian transmission network over a 10-year period, taking into account relevant forecast loads, 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 as 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 National Transmission Network Development Plan (NTNDP) and power system frequency risk review
- 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.

Clause 5.12.2 of the Rules sets out the detailed requirements for ElectraNet's Transmission Annual Planning Report. A summary of these requirements and the sections within the report that satisfy them is provided in Appendix B.

While every endeavour has been made to provide accurate information in this report, transmission system planning is subject to uncertainty, including changes to demand forecasts and generator behaviour as well as changes in government policies.

1.4 Feedback on this report

We are committed to ongoing improvement of the Transmission Annual Planning Report and its value to our customers and industry stakeholders.

Stakeholders are invited to make suggestions for future improvement by sending an email to consultation@electranet.com.au.

2. The South Australian transmission system

2.1 Overview

The South Australian transmission system connects the major load centres with various sources of generation (Figure 2-1). Most base and intermediate conventional generators are located in the Adelaide metropolitan area, while peaking power stations are spread throughout the State. The network has been developed with a high capacity 275 kV main grid that links the generators and interconnectors to major load centres (e.g. Adelaide), and to lower capacity 132 kV regional transmission systems that supply regional load centres. Power flows on the main grid often influence flows on the regional networks. Sometimes, limits on the regional networks can restrict the flow of power on the main grid.

Figure 2-1: South Australia's transmission system

The Main 275 kV Grid including interconnectors (Figure 2-2) is a meshed 275 kV network that extends from the Cultana substation near Whyalla to the South East substation near Mount Gambier. The Main Grid overlays regional networks (Figure 2-1) that cover seven regions: Metropolitan, Eastern Hills, Mid North, Riverland, South East, Eyre Peninsula and Upper North. A number of these regional systems include radial transmission lines. Detailed regional network maps and associated information are provided in Appendix C.

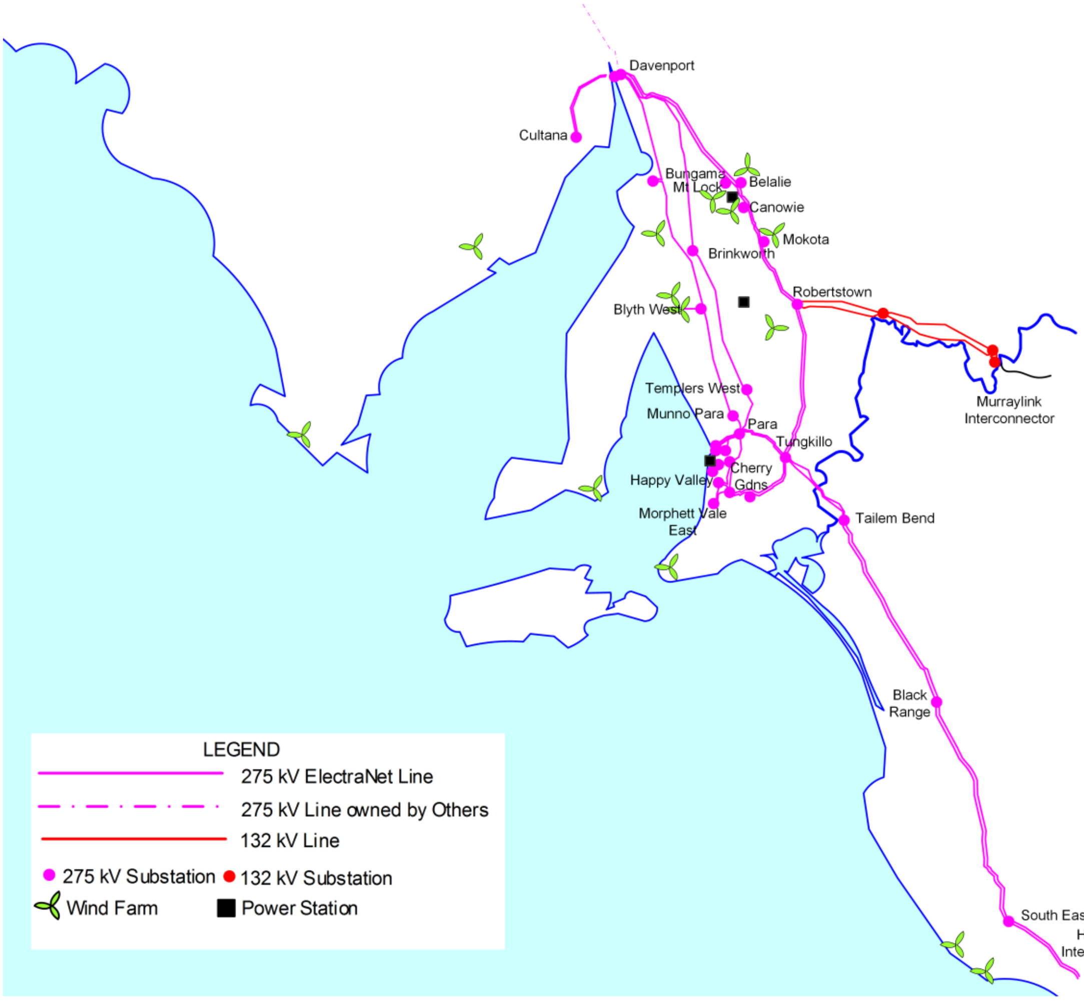

Figure 2-2: The Main 275 kV Grid including interconnectors

The Main Grid also includes two interconnectors that connect South Australia to the Victorian region of the National Electricity Market (NEM): the Heywood HVAC interconnector (est. 1989) in the state's South East and the Murraylink HVDC interconnector (est. 2002) in the Riverland. South Australian generation has typically been supplemented by imported energy from Victoria since these interconnectors were established, especially at times of high demand.

The combined maximum transfer capability for import into South Australia from Victoria under system normal operating conditions is currently 820 MW.[3] The combined maximum transfer capability for export from South Australia to Victoria under existing system normal operating conditions is 650 MW.[4] Since the Heywood interconnector

3 Consisting of 600 MW import through Heywood interconnector and 220 MW import through Murraylink interconnector.

4 Consisting of 500 MW export through Heywood interconnector and 150 MW export through Murraylink interconnector (constrained by typical voltage limits in the Riverland).

upgrade was completed in mid-2016 (section 7.2.1), the combined limit is being further increased as capacity is released in stages by AEMO.

Inter-regional transfer into and out of South Australia can be constrained to lower levels due to prior network outages, thermal limitations, and power system stability constraints. Actual transfer also depends on the market dispatch of scheduled generation, and the operation of non-scheduled generation.

2.2 Renewable energy generation

South Australia has world leading levels of intermittent renewable energy penetration compared to demand. Since 2000, about 1700 MW of wind generation has been connected to the transmission network and about 700 MW of rooftop solar photovoltaic (PV) generation has been installed since 2009. Total renewable generation, including wind and solar was about 42% of the region's electricity supply in 2015-16.[5]

Significant wind generation coupled with low system demand can result in low levels of conventional generating units connected to the system. The implications of this changing generation mix are explored in Chapter 3.

Wind is an intermittent energy source that, without significant energy storage, cannot currently be dispatched to match the load at any given instant, unlike conventional energy generation. It is important to consider the availability of wind generated power, especially during maximum demand periods. This helps to ensure that the supply-demand balance can be reliably achieved. AEMO has assessed that there is an 85% probability that wind output is typically at least 9.4% of installed capacity in South Australia during high demand periods over summer and this assumption is used in planning studies.[6]

The addition of significant domestic roof-top solar photovoltaic (PV) generation in South Australia since 2009 has also had the impact of reducing electricity demand from the transmission network, especially on sunny days. The average and minimum demand from the network has been gradually decreasing over the last five years, with slight increases in 2015-16.

Maximum demand has fluctuated due to the wide variation in heatwave conditions across different summers, but does not appear to display a consistent increasing or decreasing trend, whereas average and minimum demands can be considered to display a slowly declining trend (Figure 2-3). AEMO has assessed that roof-top solar PV generation output during high demand periods over each of the last five summers has varied between 0 and 7.4% of installed capacity, with an average contribution at such times of 4.9% of installed capacity.

5 South Australian Renewable Energy Report, AEMO, December 2016, p. 3. Available at aemo.com.au.
6 Ibid , p. 17. .

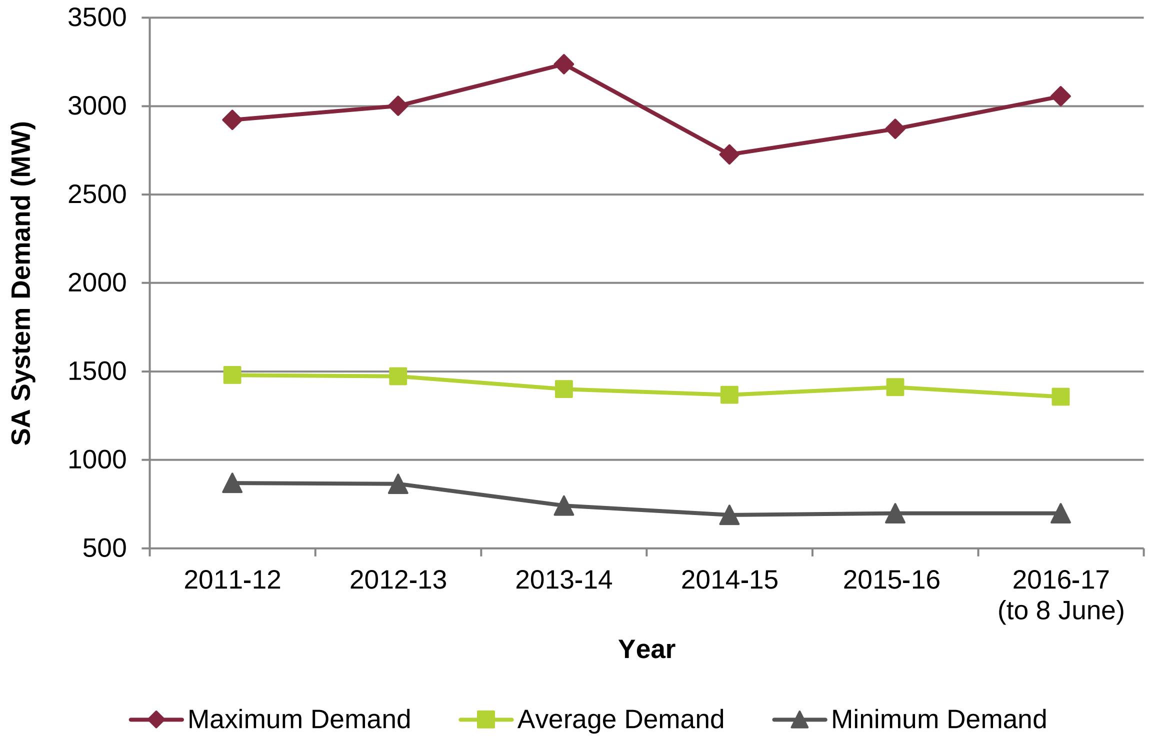

Figure 2-3: Maximum, average, and minimum electricity demands on the SA transmission network for the past six years

Note that the period from 28 September to 14 October 2016, when system demands were significantly impacted by the system black event and subsequent restoration, has been excluded in the determination of the average and minimum demands for 2016-17.

2.3 Range of South Australian demands

The South Australian load profile is very 'peaky' in nature with relatively low energy content (Figure 2 4). This means that even though demand can exceed 3000 MW on hot summer days, demands between 1000 and 2000 MW are most common throughout the year. It is important to consider the peaky nature of demand if network augmentation to meet high demand is being considered. Given that very high demands only occur for a small fraction of the year, network augmentations can often be deferred or avoided by implementing non-network solutions, such as demand-side management and local generation support.

ElectraNet actively considers these non-network solutions together with transmission and distribution network augmentation options. In this way, we can deliver the overall least cost solution to customers.

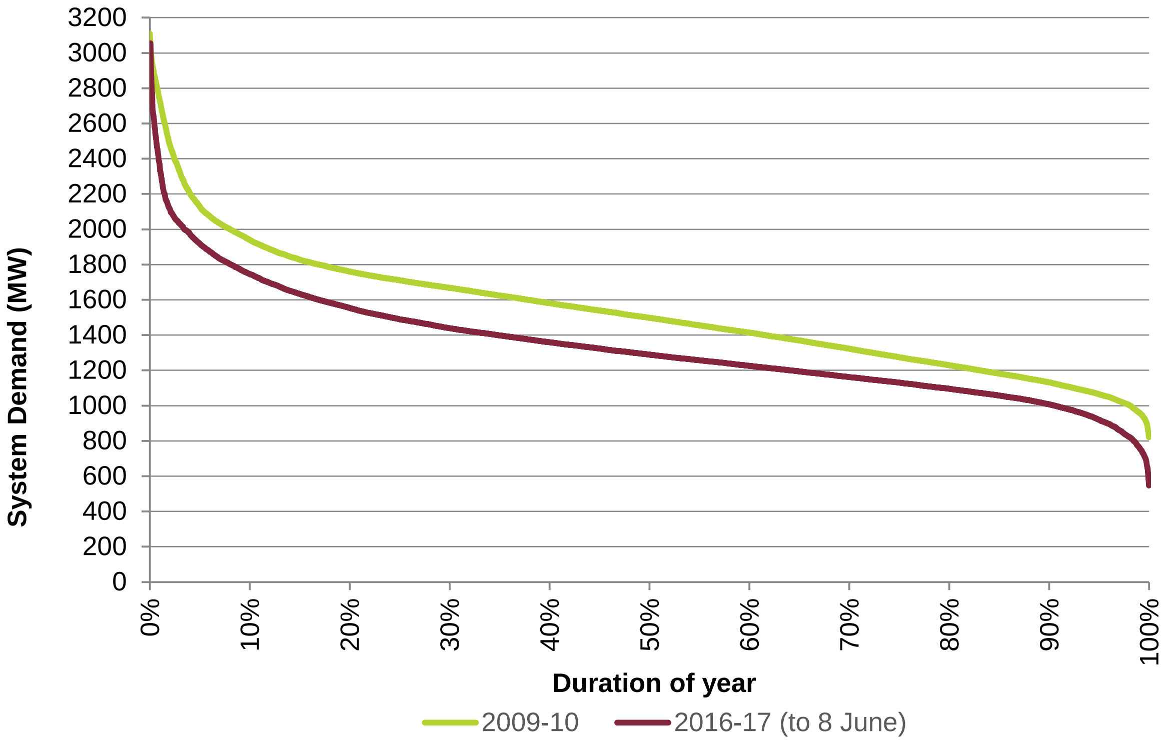

Figure 2-4: South Australian system wide load duration curves for 2009-10 and 2016-17 (to 8 June)

Note the very small percentage of time that relatively high demands (above 2,500 MW) are present on the South Australian transmission network. Maximum demands have remained at a similar level, whereas average and minimum demands have reduced substantially from 2009-10 to 2016-17.

2.4 Interconnector transfer capacity

Interconnector transfer capacity has increased since the upgrade to the Heywood interconnector was completed in mid-2016. The combined maximum transfer capacity between South Australia and Victoria under system normal operating conditions is now about 820 MW for imports to South Australia, and 650 MW for exports. Interconnected network tests continue to determine the timing of released transfer capability between the two states. Details of the combined and individual transfer capacities for Heywood and Murraylink interconnectors are provided in Appendix D.

3. A system in transition

South Australia's transmission network plays a major role in the State's electricity supply, in an environment of unprecedented change.

In October 2016, the Council of Australian Governments (COAG) Energy Ministers agreed to an independent review (the Finkel Review) to take stock of the current state of the security and reliability of the NEM and provide advice to governments on a coordinated, national reform blueprint. This review draws together and builds on the work of AEMO, the Australian Energy Market Commission (AEMC), the AER, and gas market reforms. The final report was published on 9 June 2017.[7]

The Finkel report and blueprint recognises the need to guide the transition of the market from a system of centralised, synchronous generation to a more distributed, low-emissions, flexible electricity system driven by new technologies and changing customer preferences.[8]

3.1 South Australian context

South Australia is at the forefront of this energy transformation.

Driven by renewable energy policies, rapidly evolving technology and changing customer needs, South Australia has reached world-leading levels of renewable energy penetration as a percentage of peak demand, through large scale wind generation developments and rooftop solar photovoltaic (PV) installation.

Renewable energy generation continues to grow, with approximately 42% of energy generated in South Australia now coming from renewable energy sources since the commissioning of the Hornsdale Wind Farm and the closure of Northern Power Station.[9] Federal and state government policies are expected to continue to drive further uptake of renewable energy. Overall, the generation mix in South Australia has changed substantially in recent years (Figure 3-1 and Figure 3-2).

South Australia has limited interconnection to the rest of the NEM, so has greater exposure to the system security challenges posed by high levels of renewable generation, unlike other parts of the world such as Denmark, which have greater interconnection to other networks.[10]

For these reasons, the challenges of energy transformation are nowhere more evident or pressing than in South Australia today.

7 The Finkel Review's Final Report is available at http://www.environment.gov.au/energy/publications/ electricity-market-final-report.
8 Further information is available at www.coagenergycouncil.gov.au.
9 Northern Power Station, South Australia's last coal fired generation, closed in May 2016.
10 Denmark also generates more than 40% of its electricity from intermittent (wind) energy but can meet more than 80% of its peak demand via interconnectors with Norway, Sweden and Germany.

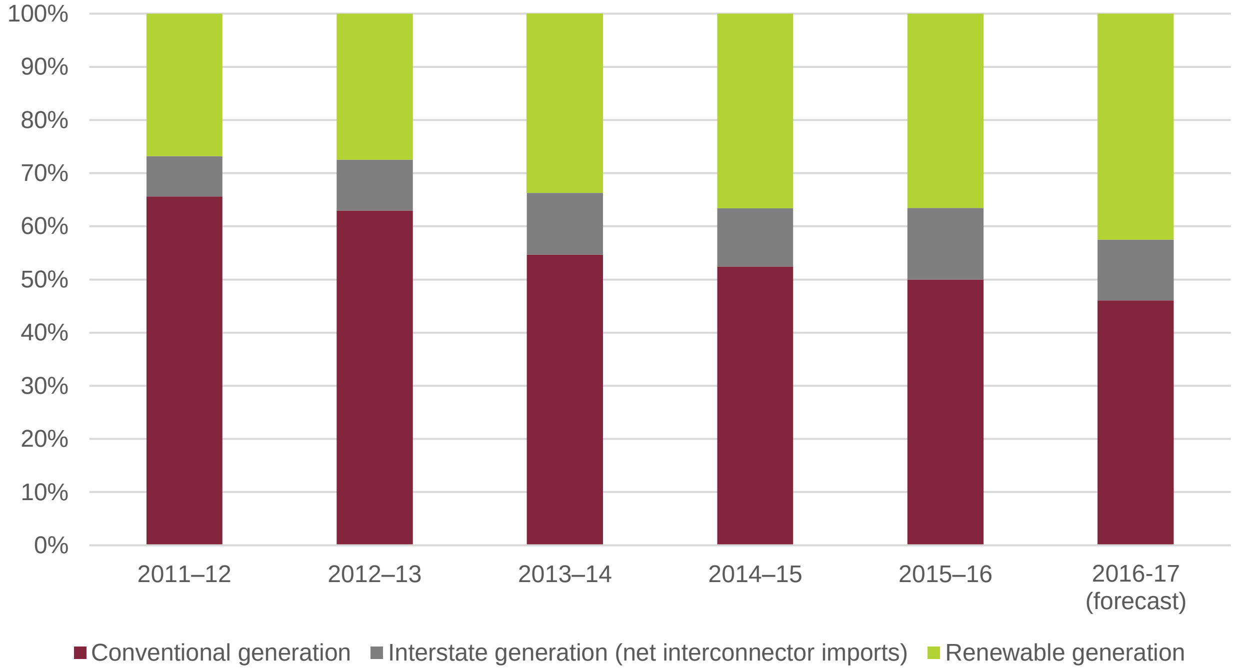

Figure 3-1: Energy generation patterns have changed significantly in recent years

Source: AEMO's 2016 South Australian Historical Market Information Report, and AEMO's 2016 South Australian Generation Forecasts report

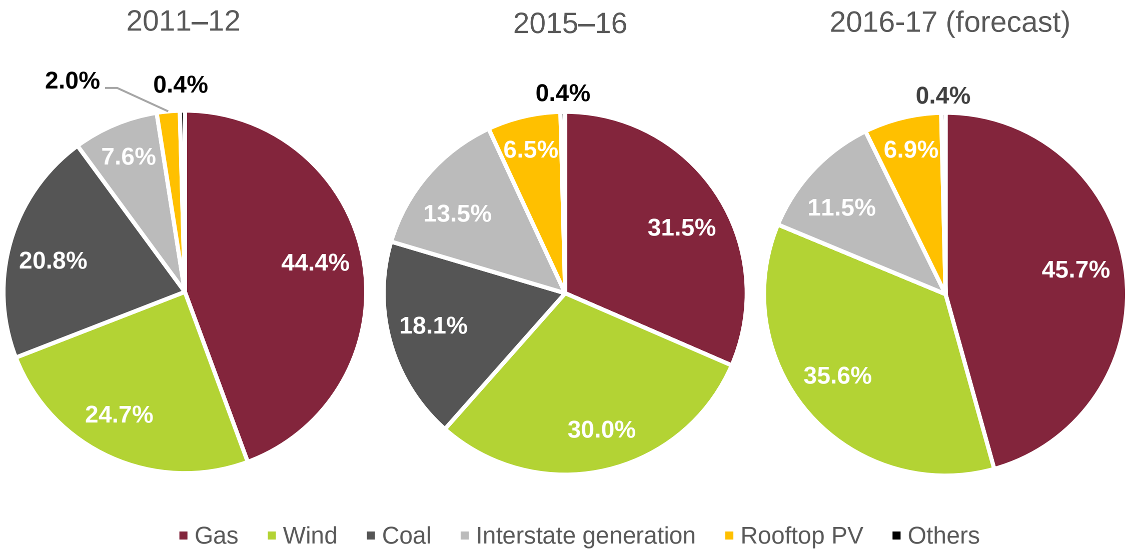

Figure 3-2: Renewable energy from wind and solar rooftop PV systems has increased significantly over the last five years

Source: AEMO's 2016 South Australian Historical Market Information Report, and AEMO's 2016 South Australian Generation Forecasts report

3.2 Recent significant events on the South Australian transmission system

In 2016-17, a number of significant events impacted the supply of electricity to large numbers of South Australian customers. These include:

- a state-wide system black event in September 2016
- severe storm activity in December 2016 damaged the SA Power Networks' distribution network resulting in supply interruptions to a large number of customers in affected areas
- high temperatures in February 2017 that resulted in demand for electricity exceeding available supply and short-term rotational load shedding (rolling blackouts)
- the loss of multiple generators near Torrens Island due to a switchyard plant explosion in March 2017.

These events are an important reminder about the value of system security and reliability to customers.

AEMO's reporting on the system black event included a number of recommendations[11]. ElectraNet is working with AEMO to implement some of these recommendations, including the development of a special protection scheme, addressing low levels of system strength and in other ways managing the risk of disruption to the power system.

The projects related to these initiatives are discussed further in this Transmission Annual Planning Report.

3.3 Current reviews and inquiries

This Transmission Annual Planning Report has been prepared at a time of significant change in the NEM.

In addition to the Finkel Review, a range of other reviews, inquiries, and Rule changes are currently underway by state and national bodies into the implications of the recent extreme weather event of 28 September 2016, and wider system security issues facing the NEM.

These include:

- a number of Parliamentary inquiries, including the Senate Select Committee Inquiry into the Resilience of Electricity Infrastructure in a Warming World and SA Legislative Council Select Committee Inquiry into the State-Wide electricity blackout of Wednesday, 28 September 2016 and subsequent power outages
- the AEMC's Review of the System Black Event in South Australia on 28 September 2016, which will be considering the need for any changes to the regulatory frameworks to address any systemic issues that contributed to the system black event
- the AEMC review of various Rule changes and its System Security Market Frameworks Review, which is considering the regulatory frameworks that affect system security in the NEM

[11] *Black System South Australia 28 September 2016*, available from aemo.com.au.

- the AEMO Future Power System Security program, which is examining operational challenges arising from the generation mix, and technical options to address these challenges[12]
- the Essential Services Commission of South Australia's (ESCOSA) investigation into how electricity companies can improve power reliability on the Eyre Peninsula
- ESCOSA's inquiry into the licensing arrangements for generators in South Australia

ElectraNet continues to participate in these reviews and inquiries, and we will ensure that our transmission plans remain consistent with their outcomes.

3.4 South Australian Government measures

On 12 October 2016, the South Australian Government introduced frequency control measures to improve the security of the power system and reduce the risks of a system black event. Changes to the Electricity (General) Regulations (SA) 2012 were introduced requiring ElectraNet to provide advice to AEMO on power transfer limits on the Heywood Interconnector so as to maintain the expected rate of change of frequency (RoCoF) to 3 Hz/s in relation to the potential non-credible loss of the Heywood interconnector.

The Government announced further measures on 14 March 2017, including the installation of a 100 MW battery, the establishment of a Government owned standby generator to provide inertia and emergency capacity, and an energy security target requiring more energy to be sourced locally from synchronous generating plant.

Implementation of these measures will progress over the coming months.[13] Implementation of the Energy Security Target component of the plan was subsequently deferred from 1 July 2017 to 1 January 2018, while clarity is sought on the Federal Government's response to the Finkel Review.[14]

These measures were introduced pending longer-term solutions expected to flow from current reviews, such as the System Security Market Frameworks Review and associated Rule changes being progressed by the AEMC. Options being considered include new technical standards for generators, provision of new services by network businesses such as ElectraNet, the procurement of additional control services by AEMO, and the potential establishment of new markets for services such as inertia.

3.5 ElectraNet initiatives

ElectraNet is pursuing a number of initiatives that support energy transformation in South Australia. These initiatives are summarised in sections 3.5.1 to 3.5.5.

3.5.1 South Australian Energy Transformation RIT-T

We have commenced a RIT-T process to explore the technical and economic feasibility of a new interconnector between South Australia and the Eastern States and alternative non-network options.

[12] Reports published by AEMO under this program are available from aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis.

[13] Government of South Australia, Our Energy Plan, available at http://ourenergyplan.sa.gov.au/.

[14] Refer to *Energy security target – Further information,* retrieved from http://www.escosa.sa.gov.au/news/energy-news/jun2017-en-est-furtherinfo on 19 June 2017.

On 7 November 2016, we published a Project Specification Consultation Report (PSCR)[15] and subsequently published a Market Modelling Approach and Assumptions Report, and a Supplementary Information Paper to provide further information and opportunity for engagement.

A cost effective new interconnector would:

- deliver system security benefits by reducing the likelihood of a system disturbance leading to a major disruption to electricity supply
- facilitate greater competition between sources of generation and thus deliver better prices for customers, by allowing increased access to a range of power sources
- open up access to the market for more renewable generation developments.

ElectraNet has identified four credible network options in consultation with the relevant Jurisdictional Planning Bodies (Figure 3-3). These involve constructing a new interconnector between South Australia and the eastern states, together with a range of potential non-network solutions. The options will be analysed further in the next stage of the RIT-T process. This analysis will take into account the South Australian government's energy plan, released on 14 March 2017.

A new interconnector project, or non-network alternative, could be operational by 2022, but would only proceed if sufficient benefits to customers can be demonstrated.

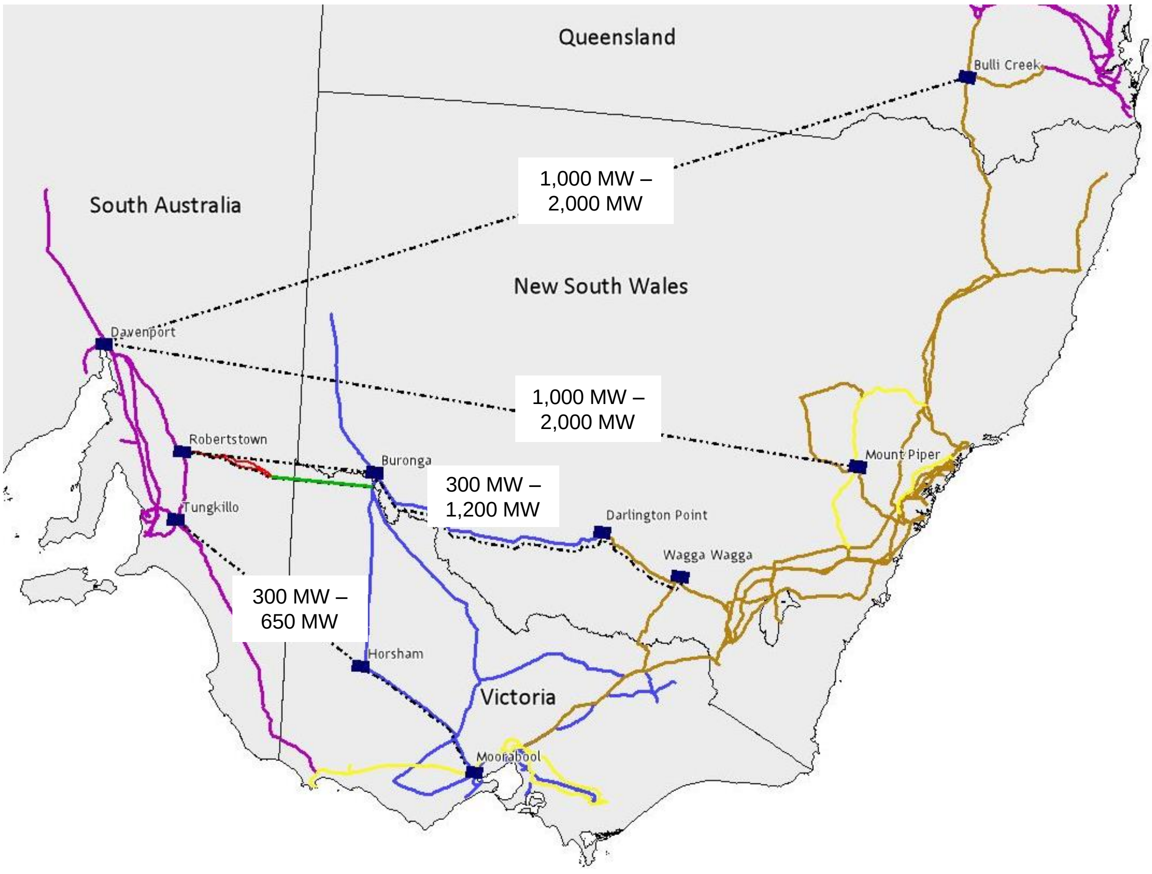

Figure 3-3: Potential new interconnector options

15 Available at electranet.com.au.

3.5.2 Grid connected battery storage

Subject to further analysis and approvals, we are pursuing a proof-of-concept battery energy storage project by this coming summer to improve the reliability and security of the power system.

This project involves installing a 30 MW 8 MWh battery energy storage system (BESS) connected at Dalrymple (Figure 3-4). The project will provide both regulated and non-regulated services.

The BESS is intended to provide regulated services to improve reliability of supply for customers at Dalrymple and provide fast frequency response that can address rate of change of frequency (RoCoF) concerns.

ElectraNet intends to lease the operation of the battery to AGL, who will use it to provide non-regulated, competitive market services.

The need for such projects has also been identified in reviews such as the Finkel Review and AEMO's Future Power System Security work program, and by the COAG Energy Council.

We believe that utility scale energy storage can play an effective role in addressing emerging system security concerns resulting from the high penetration of non-synchronous renewable generation and, thereby, be a key enabler of renewable energy on an interconnected power system.

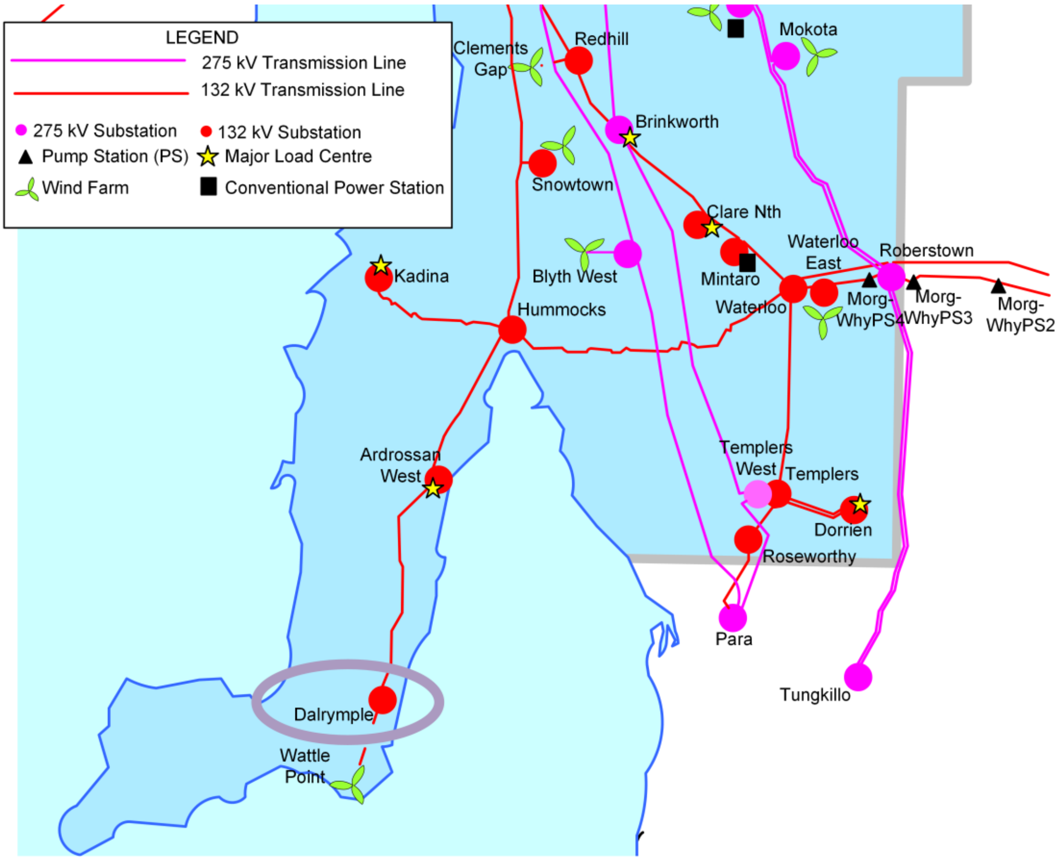

Figure 3-4: Proposed Dalrymple connection site for a 30 MW, 8 MWh battery energy storage system

3.5.3 System Strength

In recent years, the dispatch of thermal synchronous generators in South Australia has reduced significantly due to the combined impacts of ongoing wind generation developments, the uptake of embedded solar PV, and the slowing of demand growth. This reduced dispatch has significant implications for South Australian system strength.[16]

Concerns have been raised in relation to:

- the ability of existing protection systems to reliably detect and clear faults under low fault level system conditions – in particular, the use of threshold current levels in the logic of some distance relays has been identified by ElectraNet as an issue for reducing fault levels
- the impact that reducing system strength may have on existing wind farms (and in the future other power electronics enabled devices such as proposed solar farms) and consequently the introduction of instability into the system including:
  - failure for existing WFs to ride through system faults;
  - unstable control system behaviour;
  - voltage instability on the transmission system resulting in reduced transfer capability and the risk of voltage collapse

Each of these possible sources of instability carries the risk of a cascading failure resulting in significant system impacts.

AEMO's 2016 NTNDP indicated that there may be an NSCAS gap in South Australia related to system strength, but that detailed studies would be required to confirm that preliminary finding.

ElectraNet is working closely with AEMO to understand the potential impact of low system strength on power system performance, with a focus on the ability of wind farms to ride through system disturbances and return to full power output.

ElectraNet also continues to investigate the impact of low system strength on selected protection systems, to identify whether the performance of protection systems could be affected. We will continue to discuss the findings with AEMO and work towards implementing any necessary mitigation strategies.

ElectraNet supports AEMO's detailed studies to confirm whether there is an NSCAS gap relating to system strength in South Australia. AEMO has indicated that the study results are expected to be available in 2017. Should an NSCAS gap be identified we will consider appropriate measures, which could include contracting large synchronous generators to remain in service when needed, or installing synchronous condensers, to maintain a required level of system strength.

[16] System strength refers to the ability of a power system to maintain a stable voltage and frequency under all operating conditions. It is typically expressed in terms of a short circuit ratio (SCR) at generator connection points, which is defined as the fault level of the system (in MVA) divided by the rated output of the relevant generator; however, this approach does not fully account for potential interactions between different generators that are connected nearby.

3.5.4 Northern SA Voltage Control

In August 2016, ElectraNet commenced a RIT-T to address the need for improved voltage control in the northern South Australia region following the closure of Northern Power Station. A PSCR was prepared in accordance with the requirements of the Rules, as the first stage of the consultation process in relation to application of the RIT-T.

Subsequently, customers provided new information about the dynamic behaviour of customer demand at Olympic Dam, Roxby Downs, and Prominent Hill. The dynamic behaviour of this demand is critical to the identified need.

Our findings based on the new demand information provided by customers showed that voltage control in the northern South Australian region meets the requirements of the Rules. This means that the identified need for this RIT-T no longer exists.

For this reason, ElectraNet announced the cancellation of the RIT-T on 24 March 2017, as the continuation of the process was no longer required.

3.5.5 Frequency control following separation of South Australia from the NEM

AEMO has identified that uncontrolled generator trips could occur if an unplanned outage of the Heywood interconnector occurred at a time when generation from South Australian wind farms exceeded South Australian demand. To address this risk, AEMO and ElectraNet are working together to implement a coordinated Over Frequency Generation Shedding (OFGS) scheme, to trip excess generation in a controlled way to restore the balance between supply and demand and allow the South Australian frequency to recover to within the frequency operating standards.

The OFGS scheme will operate by tripping South Australian wind farms in a pre-determined sequence starting at 51.0 Hz, with those that make the smallest contribution to system inertia tripped earliest in the sequence.

As part of AEMO’s final report into the South Australian black system event on 28 September 2016, AEMO found that there are significant difficulties in forming a stable island in South Australia if the sudden loss of multiple generators in South Australia results in an unplanned outage of the Heywood interconnector along with a large deficit of South Australian supply compared to demand. In such situations, it would be preferable to avoid islanding if at all possible.

As a result, the report included a recommendation for AEMO to work with ElectraNet to investigate the feasibility of developing a Special Protection Scheme (SPS). The SPS will be designed to operate in response to sudden excessive flows on the Heywood interconnector, to initiate load shedding quickly enough to prevent separation.

ElectraNet and AEMO are currently consulting together on the design of such an SPS (section 8.9.2).

4. National transmission network developments and review of South Australian network constraints

Each year AEMO publishes a National Transmission Network Development Plan (NTNDP) in its role as the National Transmission Planner. The NTNDP considers both potential transmission and generation developments, and supports efficient coordination of investment planning in the NEM.

In December 2016, AEMO published its latest NTNDP which included the following important observations on the future direction for transmission networks:

- the NEM is moving into a new era for transmission planning:
  - transmission networks designed for transporting energy from coal generation centres will need to transform to support large-scale renewable generation development in new areas
  - transmission networks will increasingly be needed for system support services, such as frequency and voltage support, to maintain a reliable and secure supply.
- high level modelling suggests positive net benefits for potential interconnection developments, including a new interconnector linking South Australia with either New South Wales or Victoria from 2021.

AEMO observed that local network and non-network options, such as synchronous condensers or similar technologies, are also needed as part of the solution to maintain a reliable and secure supply by providing local system strength and resilience to frequency changes.

The 2016 NTNDP also:

- reflected on current network investment trends and how these were evolving
- examined the adequacy of transmission flow paths between significant generation and load centres in the NEM
- identified transmission network limitations for the outlook period (20 years)
- discussed factors impacting power system security, such as levels of inertia and the proportion of total generation managed through the dispatch process
- identified network support and control ancillary service (NSCAS) gaps which could occur in the next five years. These are services that may be needed to manage the security and reliability of the NEM in the near term.[17]

AEMO's modelling framework uses least-cost expansion models, transmission network power flow studies, and time-sequential market simulations to ensure feasible and economically justifiable results. Generation placement within the national network is based on zones identified in the NTNDP that broadly reflects actual load or generation clusters. The South Australian zones used in the NTNDP are:

- Northern South Australia (NSA)
- Adelaide (ADE)
- South East South Australia (SESA).

[17] AEMO. *2016 National Transmission Network Development Plan*. Available from aemo.com.au.

One of the inputs to network adequacy assessments in the NTNDP is AEMO's generation outlook. This means that if actual generation developments or retirements deviate from AEMO's generation outlook, some network augmentations that were not identified by the NTNDP may become efficient options.

The NTNDP focuses on the ability of the national transmission network to reliably support major power transfers between generation and demand centres in the NEM. As a result, the 2016 NTNDP did not consider augmentations that may arise from:

- planning standards that differ from the planning standards and criteria defined in the NTNDP
- ongoing local transmission needs to meet localised peak demand outside of the 10% Probability of Exceedance (POE) regional maximum demand
- the appearance of new or contract load that are outside the available forecasts.

4.1 Network limitations identified in the NTNDP

The 2016 NTNDP classifies emerging network limitations into one of two categories: reliability or economic dispatch limitations. There are no emerging reliability limitations identified in South Australia.

Five potential economic dispatch limitations were identified on the South Australian transmission network (Table 4-1). AEMO identified that these limitations will occur mainly at times of high wind or solar generation.[18] The 2015 NTNDP had identified the same five potential economic dispatch limitations in South Australia.

Table 4-1: Potential economic dispatch limitations identified in the 2016 NTNDP

NTNDP zone	Potential transmission limitations	Dispatch scenario	Possible solution	NTNDP scenario	2017 TAPR reference
NSA	NSA-ADE 275 kV corridor	High wind/solar generation in NSA	Uprate 275 kV lines between Davenport and Robertstown	Neutral all	Section 8.5.4
NSA	132 kV network in the Mid North region	High wind/solar generation in NSA	Uprate relevant 132 kV lines in Mid North region and implement dynamic line ratings	Neutral all, Low Grid Demand Base case	Section 8.5.2
NSA	132 kV network in the Riverland region	High wind/solar generation in NSA and high Murraylink export to Victoria	New interconnector to SA Install reactive support in Riverland region to increase transfer capacity of existing 132 kV network Uprate 132 kV lines in the Riverland	Neutral all, Low Grid Demand Base case	Sections 8.3.2 and 8.5.1

[18] AEMO. *2016 NTNDP,* p. . Available from aemo.com.au.

NTNDP zone	Potential transmission limitations	Dispatch scenario	Possible solution	NTNDP scenario	2017 TAPR reference
NSA	132 kV network in the Eyre Peninsula region	High wind/solar generation in Eyre Peninsula region of NSA	Rebuild Eyre Peninsula 132 kV lines as double circuit lines	Neutral all, Low Grid Demand Base case	Section 8.4.1
SESA	Tungkillo-Tailem Bend-South East corridor	High wind/solar generation in NSA and ADE	Install second 275 kV circuit between Tailem Bend and Tungkillo New interconnector to SA	Neutral, Low Grid Demand Base case	Sections 8.5.8 and 8.3.2

ElectraNet's analysis indicates that these limitations (Table 4-1) are occurring now, or are expected to occur in the near future. The occurrence and impact of the forecast congestion will increase as new wind farms continue to be connected in the NSA zone. Further, forecast increases in gas prices across the east coast of Australia (including in South 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. ElectraNet will continue to engage with AEMO and explore the appropriate network developments to efficiently address network congestion.

4.2 Transmission network constraints

AEMO uses constraint equations 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 what it would have been if there was no constraint. Generators (and interconnectors) can be either constrained on (above the level that would otherwise be set by the market) or constrained down (below the level that would otherwise be set by the market).

AEMO publishes the marginal value of a constraint when it binds. The marginal value indicates its impact on market prices, but this measure is only an approximation and can be misleading in some instances. At times, constraints that have a relatively small impact can report large marginal values due to interactions between the network limitation, price at the time and the bids of generators affected by the constraint.

ElectraNet has assessed the top binding network constraints that impacted transmission network and interconnector flows during the 2016 calendar year (Table 4-2). Constraints selected for assessment were in the top ten by impact on marginal value or by binding duration in 2016. Some constraints have been grouped as they manage the same network limit or operating condition. For example, two constraints might both manage the overload of the same network element for different contingency events.

Many of the constraints (Table 4-2) are managing limitations and contingencies outside of South Australia. Most of those are in Victoria and come under AEMO's oversight as the Victorian jurisdictional transmission planner.

Table 4-2: Constraint equations, descriptions and ranking

Where constraints are closely related to one another, they have been grouped together. Note that constraints used to manage frequency control ancillary services have not been included.

Constraint equation and description	2016 marginal value (2015)	Rank by 2016 marginal value	2016 hours binding (2015)	Rank by 2016 hours binding	Commentary
NSA_S_POR03_10 Run Port Lincoln generators in accordance with Network Support Agreement	2,568,534 (2,577,658)	1	15.3 (15.7)	109	ElectraNet dispatches this generation under a network support agreement to supply the Port Lincoln load under islanded conditions ElectraNet commenced a RIT-T in April 2017 to investigate the most economical way of continuing to meet ETC reliability standards on the Eyre Peninsula after the existing network support arrangement expires in December 2018
NSA_S_POR01_05 Run Port Lincoln generators in accordance with Network Support Agreement	1,337,956 (0)	4	8 (0)	143	
NSA_S_POR03_15 Run Port Lincoln generators in accordance with Network Support Agreement	1,202,877 (0)	6	7.2 (0)	155	
NSA_S_POR01_ISLD Run Port Lincoln generators in accordance with Network Support Agreement	1,005,793 (0)	8	6 (0)	174	
S_PLN_ISL2 Run Port Lincoln generators in accordance with Network Support Agreement	988,797 (0)	9	7.4 (0)	151	
V^S_NIL_SA_RECLASS Prevent flow on Heywood interconnector from exceeding 700 MW if a reduction in power output from multiple generators in SA was to occur	1,702,651 (0)	2	179.3 (0)	14	AEMO applied this constraint after the system black event of 28 September 2016, to allow for the possibility that multiple wind farms might simultaneously reduce their output as a response to system voltage fluctuations This constraint equation is no longer invoked, as it was removed in late 2016

Constraint equation and description	2016 marginal value (2015)	Rank by 2016 marginal value	2016 hours binding (2015)	Rank by 2016 hours binding	Commentary
S-STTX_SNWF Snowtown wind farm constrained to 0 MW due to connection point outage	1,362,930 (1,238)	3	210 (1.2)	12	AEMO uses this constraint to manage connection point outages
SVML_000 Murraylink unavailable for transfers from SA to Victoria	1,217,528 (0)	5	134.8 (0)	21	This constraint could be alleviated by duplicating the Murraylink HVDC interconnector, or by establishing a new high capacity interconnector between the Northern region of SA and the eastern states
VSML_ZERO Murraylink unavailable for transfers from Victoria to SA	640,207 (99,360)	16	301.6 (78.2)	7	
V::S_TB_275KV_W_B_1 Avoid transient instability of generators if an outage of one of the South East to Tailem Bend 275 kV lines was to occur while the Tailem Bend 275 kV West Bus is out of service	1,180,827 (0)	7	232.3 (0)	11	This constraint equation was invoked during work to upgrade the Heywood interconnector in 2016 The work has been completed, so the constraint equation has now been removed
S>NIL_HUWT_STBG Avoid overloading the Snowtown to Bungama 132 kV line if an outage of the Hummocks to Waterloo 132 kV line was to occur	968,995 (738)	10	78.9 (0.9)	35	ElectraNet improved the application of dynamic ratings on the Snowtown to Bungama 132 kV line in May 2017, which alleviates this constraint
VSML_220 Avoid exceeding Murraylink interconnector maximum capacity during normal conditions	890,029 (183,598)	12	468.1 (123.4)	3	This constraint could be alleviated by duplicating the Murraylink HVDC interconnector, or by establishing a new high capacity interconnector between the Northern region of SA and the eastern states
V_S_NIL_ROCOF Prevent rate of change of frequency in SA from exceeding 3 Hz/s if a non-credible outage of the Heywood interconnector was to occur	303,197 (0)	26	393 (0)	4	This constraint could be alleviated by running more high inertia generators in SA, or by installing high inertia synchronous condensers in SA

Constraint equation and description	2016 marginal value (2015)	Rank by 2016 marginal value	2016 hours binding (2015)	Rank by 2016 hours binding	Commentary
V>>V_NIL_2A_R Avoid overload of the South Morang 500/300 kV transformer during system normal conditions	136,123 (80,139)	43	966 (705.2)	1	AEMO's 2016 Victorian Annual Transmission Planning Report indicates that the market impact of these constraints does not currently justify augmenting the network AEMO will continue to monitor the performance of this constraint and explore options to increase the export limit to New South Wales
S>V_NIL_NIL_RBNW Avoid overload of the Robertstown to North West Bend #1 or #2 line during system normal conditions	127,120 (270,134)	44	586.8 (451.3)	2	Murraylink exported at a significant level more often in 2016 than in 2015, leading to a higher incidence of this constraint The uprate of the Robertstown to North West Bend 132 kV line No. 1 by ElectraNet in 2015, and the planned uprate of the Robertstown to North West Bend 132 kV line No. 2 in 2017 (see section 8.5.1), will alleviate this constraint
V>>N-NIL_HA Avoid overload of the Murray to Upper Tumut 330 kV line if an outage of the Murray to Lower Tumut 330 kV line was to occur	97,517 (27,769)	60	367.9 (35.9)	5	AEMO monitors the performance of this constraint AEMO's 2016 Victorian Transmission Annual Planning Report indicates that the market benefits of increasing the Victoria - New South Wales export capability is marginally lower than the cost, even if a generation surplus in Victoria continues over the next 10 years
V::N_NIL_V2 Avoid transient instability of generators if an outage of one of the 500 kV lines between Heywood and South Morang was to occur	71,764 (9,394)	66	326.2 (73.7)	6	AEMO monitors the performance of this constraint AEMO's 2016 Victorian Transmission Annual Planning Report indicates that the market benefits of increasing the Victoria - New South Wales export capability is marginally lower than the cost, even if a generation surplus in Victoria continues over the next 10 years
V::N_NIL_V4 Avoid transient instability of generators if an outage of one of the 500 kV lines between Heywood and South Morang was to occur	37,846 (82,929)	91	252.3 (759.7)	9	
V::S_NIL_MAXG_AUTO Avoid transient instability of generators if an outage of SA's largest online generator was to occur	54,436 (118,157)	76	267.7 (241.1)	8	This constraint has been alleviated by the installation of series capacitors at Black Range in 2016, and by the increase of Heywood interconnector's import capability to 600 MW

Constraint equation and description	2016 marginal value (2015)	Rank by 2016 marginal value	2016 hours binding (2015)	Rank by 2016 hours binding	Commentary
VS_250_DYN Limit the supply-demand imbalance to no more than 250 MW if a credible outage of the Heywood interconnector was to occur	123,270 (2,796)	50	244.8 (18.3)	10	The high hours binding of this constraint in 2016 was mainly caused by line outages during the Heywood interconnector upgrade This constraint could be alleviated by establishing a new high capacity interconnector between SA and the eastern states

4.3 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, or higher gas prices. Such developments may lead to network constraints that are efficient to address with network augmentation projects (or non-network alternatives) that provide a net market benefit.

ElectraNet has identified a range of potential future inter-regional and intra-regional market benefit projects (Table 4-3 and Table 4-4 respectively). Some of these projects would be required if the network develops along the lines of the 2016 NTNDP generator expansion forecasts.

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 forecasts. The specific projects that will provide net market benefits are often uncertain until actual generator investment decisions are made or there is sufficient information available to proceed with a RIT-T. Project timings have not been proposed or presented because of this uncertainty.

The potential projects (Table 4-3, Table 4-4), whilst high level, have been identified through constraint and planning analysis. ElectraNet expects that these projects would reduce network congestion in the future and hence may deliver sufficient benefits to customers to warrant development. These projects may also lead to minor improvements in network reliability.

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

Project name	Drivers/value of potential project	Description of potential project	Capacity/benefit provided	Lead time	Cost ($M)
New Interconnector between South Australia and the Eastern States	Increased wholesale market competition to put downward pressure on electricity prices in South Australia, improved system security, supporting development of renewable generation and reduced transmission losses	ElectraNet proposed four interconnector options in the South Australian Energy Transformation Project Specification Consultation Report that was published in November 2016 The net market benefit of those options, along with non-interconnector options and the impact of the SA Government's Energy Plan, are currently being evaluated	300 MW to 2,000 MW capacity increase	1-2 years RIT-T 3-5 years detailed design and delivery	500 to 2,500
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 and install dynamic reactive support at Tailem Bend As part of the assessment that is being done for the South Australian Energy Transformation RIT-T, ElectraNet is evaluating the net market benefit of stringing this vacant circuit	400-600 MW increase in line section capacity	1-2 years RIT-T 2 years delivery	40 to 60

Table 4-4: Potential intra-regional market benefit projects

Project name	Drivers/value of potential project	Description of potential project	Capacity/benefit provided	Lead time	Cost ($M)
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 AC double circuit line with twin conductors	1200+ MW capacity increase	1-2 years RIT-T 5 years easement acquisition, detailed design and delivery	300–600
Tie Davenport to 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	1-2 years RIT-T 2 years detailed design and delivery	10–20
Tie Robertstown to 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	1-2 years	3-6
Strengthen Mid North 275 kV network	Increase in renewable generation in the Mid North or Eyre Peninsula	Various line uprating and application of dynamic line ratings depending on generator developments.	Capacity increase depending on location of generation and local network capability	2–3 years	<5 (total)
Reconfigure Mid North 132 kV network	Increased renewable generation on the Mid North network	Various potential reconfiguration options depending 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

4.4 Future network congestion

Following recent increases in capability across the Heywood and Murraylink interconnectors (installation of series capacitors at Black Range and uprating of lines), the generally higher flows across both interconnector corridors are at times expected to remain constrained by network import and export limitations (Table 4-5).

Further significant development of renewable energy generation in South Australia could lead to additional congestion on the transmission network.

This will depend on future generator connection locations. The limitations that could bind as a result of such additional renewable generation connections are highlighted in Table 4-5. Where possible, references to other sections of this report are provided that contain information regarding projects or initiatives that would resolve or mitigate the forecast limitations.

Table 4-5: Forecast South Australian transmission network congestion

Limitation	Status	Affected I'connector	Constrained flow: import or export;	Reference to potential mitigating project(s)
Lower South East Region: thermal ratings of 275 kV lines between Tailem Bend and Heywood	Forecast post-Heywood interconnector upgrade	Heywood	Import and export	Section 8.5.3
Mid North Region: thermal ratings of 275 kV lines between Davenport and Brinkworth	Depends on future generation connections	Intra-regional	N/A	No project currently proposed
Mid North Region: thermal ratings of 275 kV lines between Davenport and Robertstown	Depends on future generation connections	Intra-regional	N/A	Section 8.5.4
Mid North Region: thermal ratings of 132 kV lines between Robertstown and North West Bend	Existing	Murraylink	Export	Section 8.5.1
Mid North Region: thermal ratings of 132 kV lines between Waterloo and Templers	Existing; could be exacerbated by future generation connections	Intra-regional	N/A	Section 8.5.6
Mid North Region: thermal ratings of 132 kV lines between Waterloo East and Robertstown	Existing	Murraylink	Export	Section 8.5.2
North West Bend, Berri and Monash: voltage limitations	Existing	Murraylink	Export	No project currently proposed
Robertstown 275/132 kV transformers: thermal ratings	Depends on future generation connections	Intra-regional and Murraylink	Export	Section 8.5.9

Limitation	Status	Affected I'connector	Constrained flow: import or export;	Reference to potential mitigating project(s)
South East Region: thermal ratings of 275 kV lines between Tailem Bend and Tungkillo	Forecast post-Heywood interconnector upgrade	Heywood	Import and export	Section 8.5.3
South East Region: voltage stability limitations	Existing, and forecast post-Heywood interconnector upgrade	Heywood	Import and export	Section 8.5.5
Transient instability between South Australia and the rest of the NEM	Existing, and forecast post-Heywood interconnector upgrade	Heywood and Murraylink	Import and export	Section 8.3.2

Congestion in Victoria frequently impacts the transfer capability of the Heywood and Murraylink interconnectors. This will occur more often as South Australian network limitations are addressed and as renewable generation increases 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 exports from Victoria to NSW (impacts Murraylink and the Heywood Interconnector)
- South Morang 500/330 kV transformer limitations in Victoria (impacts the Heywood Interconnector)
- transient stability limitations on export from Victoria to South Australia (impacts the Heywood Interconnector).

5. Summer (2016-17) demand review and forecasts

Forecasting electricity demand and network loading conditions is important because transmission system projects take significant time to implement.

Each registered participant connected to ElectraNet's network is required to provide demand forecast information on an annual basis according to Schedule 5.7 of the Rules. ElectraNet uses this information and observed data (section 5.1) to forecast electricity demand (section 5.2).

5.1 Summer demand review[19]

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, can drive state-wide demands to levels of more than double the average.

The holiday period that begins at Christmas time and extends until Australia Day reduces the impact of high temperatures 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 weekdays outside of the holiday period.

Individual connection points, however, may experience isolated heat events, driving high localised demands independent of state-wide demand levels. This is especially possible in holiday regions, or in regions where local industry has a seasonal demand (for example, vintage in wine regions).

According to the Bureau of Meteorology, average maximum and minimum Adelaide temperatures during the 2016-17 summer were within one degree of their long term summer average (Table 5-1). Highlights include:

- many Adelaide suburbs recorded temperatures over 40 °C on 8 February, the hottest day of the summer for the Adelaide region with about three times the normal relative humidity for Adelaide and very low wind speeds[20]
- the rest of the state recorded warmer than average temperatures across most of the rest of South Australia, including average minimum temperatures across the state that were, as a whole, the fifth warmest on record – the warmest summer nights since 2005-06[21]
- state-wide demand reached a maximum of 3,105 MW on Wednesday 8 February 2017[22]
- demand exceeded 2,700 MW on 7 occasions during the 2016-17 summer (Table 5-2).

[19] Connection points in South Australia experience maximum demands in summer.
[20] *Adelaide in summer 2016-17: very wet with temperatures close to average*, Bureau of Meteorology, 1 March 2017 – available at http://www.bom.gov.au/climate/current/season/sa/adelaide.shtml. Retrieved 16 May 2017.
[21] *South Australia in summer 2016-17: wet with warm temperatures*, Bureau of Meteorology, 1 March 2017 – available at http://www.bom.gov.au/climate/current/season/sa/summary.shtml. Retrieved 16 May 2017.
[22] The measured maximum demand preceded a short period of load shedding to manage the balance between supply and demand, in the absence of which the demand could have been higher.

Table 5-1: 2016-17 summer temperature data compared with long term trends

	December		January		February		March	
	Long term trend	2016-17	Long term trend	2016-17	Long term trend	2016-17	Long term trend	2016-17
Max temp (°C)	43.4	41.3	45.7	41.1	44.7	42.4	41.9	38.6
Date of max temp	19-12-2013	25/12/2016	28-01-2009	17/01/2017	22-02-2014	08/02/2017	06-03-1986	01/03/2017
Average max temp	27.2	28.7	29.4	30.7	29.5	28.7	26.5	29.3
Days* >30°C	9.8	12	13.5	14	12.6	11	8.2	16
Days* >35°C	3.7	6	6.3	8	5.5	4	2.6	3
Days* >40°C	0.7	1	1.8	2	0.9	2	0.1	0
Difference between 2016-17 average max and long term trend	1.5		1.3		-0.8		2.8	

*Mean days for long term trend data, actual days for 2016-17 data

Source: Bureau of Meteorology

Table 5-2: Highest demand periods in summer 2016-17

Date	Maximum demand (MW)[23]	Maximum temperature (°C)	Temperature demand index (°C)
Wednesday 8 February	3,105[24]	42.2	36.7
Thursday 9 February	3,063	40.8	37.5
Friday 10 February	2,920	39.8	36.0
Friday 6 January	2,791	39.4	35.3
Tuesday 17 January	2,768	40.9	34.5
Wednesday 1 March	2,753	38.5	34.8
Tuesday 28 February	2,723	37.6	34.0

A key high-level indicator of demand is the temperature demand index. It identifies temperature patterns that have the potential to deliver a 10% POE demand level.

23 These values include demand supplied by non-scheduled generation and embedded generation connected to the distribution network, but exclude demand provided by rooftop solar PV generation.

24 The measured maximum demand preceded a short period of load shedding to manage the balance between supply and demand, in the absence of which the demand could have been higher.

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[25]) occurring after Australia Day provides the necessary temperature conditions to achieve 10% POE at a state level.[26]

Despite the warmer than average temperatures across most of South Australia, the temperature index did not reach 38 at any time during the summer (Figure 5 1). The highest value of the temperature demand index was 37.8 °C; however, as this occurred on Saturday 7 January, State demand did not exceed 2,700 MW. The three next highest values of the temperature index occurred from Wednesday 8 February to Friday 10 February, with South Australia recording its maximum demand for the summer on Thursday, 9 February 2017.

Given the above, ElectraNet expects that the maximum State demand recorded during the 2016-17 summer is likely to be slightly below the 10% POE maximum demand level.

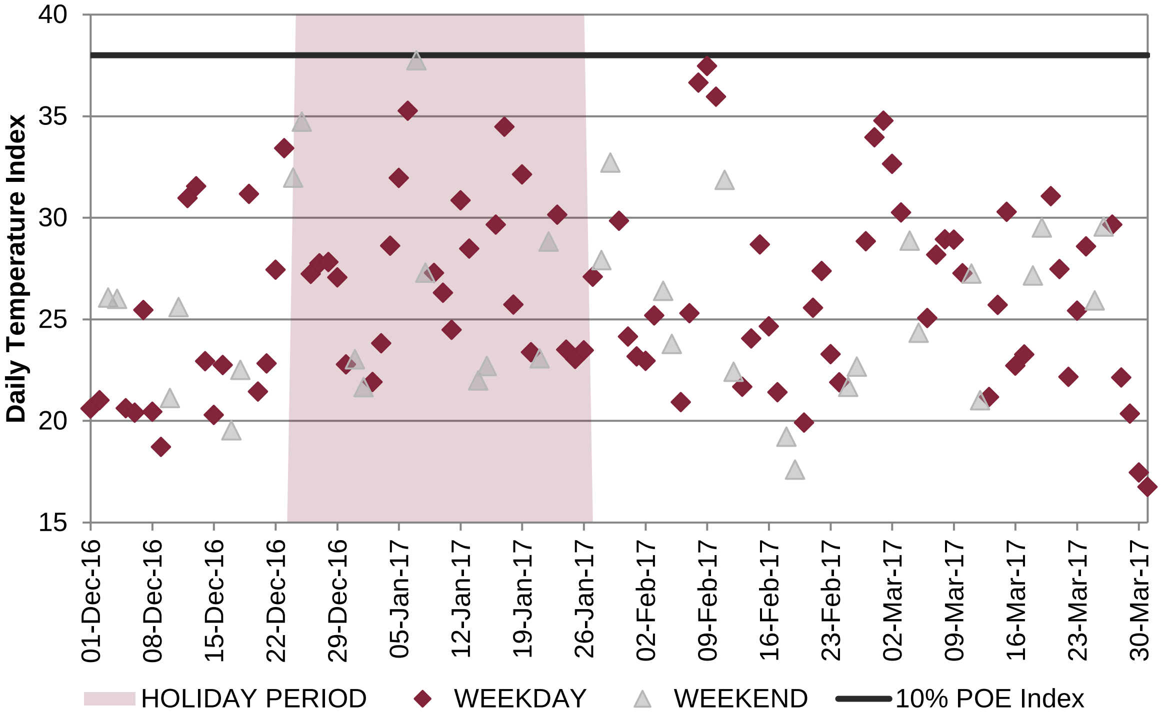

Figure 5-1: Daily temperature index for summer 2016-17

---

25 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.

26 Analysis of data from over 100 years found that this threshold was exceeded 19 times 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 is considered an appropriate indicator of 10% POE demand conditions.

5.1.1 Connection point review

As the need for transmission reinforcement is often localised, ElectraNet and SA Power Networks review each connection point on the transmission system. During summer 2016-17, most connection points recorded maximum demands that were between 85% and 100% of their forecast 10% POE maximum demand.

Thirteen bulk connection points exceeded 100% of ElectraNet's 10% POE connection point demand forecasts (Table 5-3), but all were still within the network capability. Six connection points failed to reach 85% of their 10% POE forecast (Table 5-4).

ElectraNet and SA Power Networks' 2017 review of connection point forecasts will consider the measured maximum demands from summer 2016-17.

Table 5-3: Recorded demands more than 100% of 10% POE demand forecast in summer 2016-17

Connection point	ElectraNet 10% POE demand forecast (MW)	AEMO 10% POE forecast (MW)	Actual Maximum (MW)	Date and time of maximum demand (Market time)
Leigh Creek South	1.0	1.0	1.2	9 February 20:30
Blanche	31.8	33.8	35.6	8 February 17:30
Wudinna	13.7	15.0	14.9	8 February 19:00
Baroota	7.6	7.9	8.2	9 February 19:00
Hummocks	13.0	14.6	13.7	8 February 19:00
Yadnarie	7.8	9.3	8.2	8 February 19:00
Neuroodla	0.9	1.0	0.9	9 February 19:30
Kanmantoo	1.5	1.6	1.6	8 February 19:00
Brinkworth	4.5	4.8	4.6	10 February 19:00
Templers	29.2	31.0	30.0	8 February 19:00
Waterloo	8.3	10.2	8.5	9 February 19:00
Western Suburbs	415.1	442.3	420.8	9 February 18:30
Eastern Suburbs	715.5	722.1	718.0	9 February 17:00

Table 5-4: Recorded demands less than 85% of 10% POE demand forecast in summer 2016-17

Connection point	ElectraNet 10% POE demand forecast (MW)	AEMO 10% POE forecast (MW)	Actual Maximum (MW)	Date and time of maximum demand (Market time)
Snuggery Rural	16.2	14.8	13.3	7January 17:30
Keith	24.5	24.8	19.3	5 January 19:00
Mt Gunson	0.2	0.2	0.1[27]	18 January 14:00
Port Pirie System	70.7	67.9	51.6	8 February 19:30
Stony Point	0.2	0.2	0.1[24]	19 January 21:00
Penola West	8.8	7.0	5.5	1 March 19:00

[27] Actual maximum is within the margin of error of the 10% POE demand forecast

5.2 Demand forecast

ElectraNet considers that our 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 collaborates with AEMO to receive forecasts from direct connect customers. ElectraNet and SA Power Networks work together to determine and agree on any adjustments required to account for embedded generators and major customer loads connected directly to the distribution network.

Transmission network development plans are revised as connection point demand forecasts are updated. The development plans presented in this report are based on the connection point demand forecasts that were provided by SA Power Networks in November 2016. Details of the forecast can be found in ElectraNet's *2017 South Australian Connection Point Forecasts Report*.[28] In most cases there is very little change in the projections of future demand for most connection points compared to the demand forecast which was used as the basis for the augmentation plans presented in the 2016 Transmission Annual Planning Report.

In June 2016, AEMO published a minimum demand forecast for South Australia as part of the 2016 *National Electricity Forecasting Report* (NEFR).[29] ElectraNet has used that forecast to determine future needs for improved voltage control at times of minimum demand in South Australia.

5.2.1 Review of 2016 National Electricity Forecasting Report

AEMO published an annual state-wide demand forecast for South Australia as part of the NEFR. In 2016, AEMO forecast that:

- State-wide demand would decline at an average rate of 1% per annum across the forecast period, due to continuing high growth in rooftop solar PV – a rate higher than typical in other regions – and also due to a projected decline in business sector consumption
- average demands to continue to reduce over the forecast period
- In contrast, minimum demand on the South Australian transmission network to reduce rapidly, indicating that demand centres will actually provide net injection of generation into the South Australian transmission system from about 2026-27

AEMO's 2016 NEFR 10% POE neutral growth forecasts for South Australian maximum, average[30] and minimum demand are presented in Figure 5-2, along with the previous three years and current year of estimated actual maximum, average and minimum demands.

AEMO's 2017 NEFR had not yet been published at the time of writing this Transmission Annual Planning Report.

28 Available from electranet.com.au.
29 Available from aemo.com.au.
30 We have calculated average demand forecasts from AEMO's forecasts of annual energy.

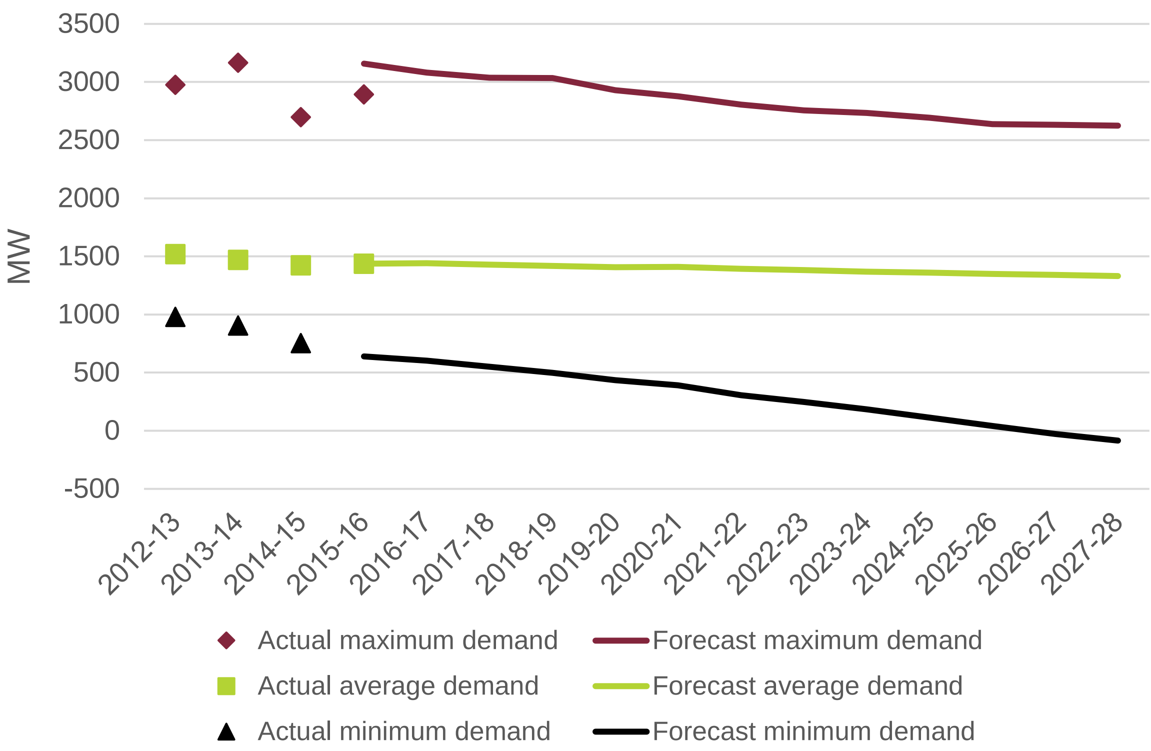

Figure 5-2: AEMO's 2016 NEFR neutral growth forecasts

Source: AEMO 2016 NEFR SA Operational Demand

5.2.2 Connection point forecasts

In July 2016, AEMO published updated connection point forecasts for South Australia. These forecasts, along with information on AEMO's methodology for connection point forecasting can be found on AEMO's website.[31]

ElectraNet compares its forecasts (as published in the *2017 Connection Point Forecasts Report*)[32] against AEMO's forecasts. At an aggregate level, AEMO's and ElectraNet's connection point forecasts are both reconciled to AEMO's State-level forecast from the 2016 NEFR during their development. Thus the connection point forecasts inherently reconcile to one another.

When individual connection point forecasts are considered there are some differences between the two forecasts, but neither forecast is consistently higher or lower than the other. The difference between the ElectraNet and AEMO connection point forecasts has no impact on network limitations or development plans within the next ten years. ElectraNet uses both the AEMO State-wide forecasts and its own connection point forecasts depending on the needs of a particular planning study.

---

31 Available from aemo.com.au.
32 Available from electranet.com.au.

6. Connection opportunities

Electricity supply in the South Australian region comes from local generation as well as the Heywood and Murraylink interconnectors.

AEMO projects that all NEM regions will meet the reliability standard set in the Rules over the next two years, based on the generation and storage expected to be available. However, AEMO notes that South Australia is considered most at risk of breaching the reliability standard, and that to meet the standard:

- All existing conventional generation must be available and operating
- Pelican Point Power Station must return to full service
- the new battery storage and diesel generation to be contracted by the South Australian Government (as part of its Energy Plan) must be available as planned.[33]

ElectraNet encourages potential new generators or customers, to contact its Corporate Development Team (connection@electranet.com.au) to discuss their needs.

In this section we outline connection opportunities for generators (section 6.1) and customers (section 6.2) and discuss the factors that influence them, followed by a summary of the opportunities (section 6.3). We also identify proposed new connection points (section 6.4), and current and potential transmission connection hubs (section 6.5).

6.1 Connection opportunities for generators

ElectraNet has conducted a high level assessment of the ability of existing transmission network nodes and connection points to accommodate new generator connections. This study considered a range of demand, generation, and interconnector operating conditions to determine the indicative maximum generation capacity that could be connected without breaching existing line and transformer thermal ratings, under system normal and single credible contingency conditions.

However, it may be noted this assessment is limited to a few operating conditions and does not attempt to define the amount and value of constraints that may be experienced in terms of energy lost by connecting generation at any particular location. Such detailed market impact assessment should be carried out by the parties seeking connection to the network.

Almost any point in the 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 close to fuel resources, including wind. However, there is a risk of clustering and potential issues with system security and potential constraints that proponents need to be mindful of. The sites that are electrically favourable for connecting generation are located along the 275 kV backbone from Port Augusta (near Davenport and Cultana) to the South East (near Penola and Mount Gambier). It is also important to note that connection of generation anywhere from Tungkillo through to Tailem Bend and South East will directly have an impact on the ability to import real power from Victoria and the rest of the NEM.

[33] AEMO, *Energy Supply Outlook*, June 2017, p. 3. Available from aemo.com.au.

In the metropolitan region, population density limits the ability to economically extend the network. Also existing fault levels (Appendix E) are approaching the plant capability limits of both ElectraNet's and SA Power Networks' assets, particularly in the vicinity of Torrens Island, LeFevre, Kilburn, Northfield, Magill and within the Adelaide central business district (CBD). Therefore, while the existing Metropolitan 275/66 kV system otherwise has capacity to accept new generation connections, this could accelerate the need for major augmentation and/or replacement of existing transmission and distribution assets to address fault level issues.

The ability to accommodate additional generation was assessed for a range of operating conditions (Table 6-1). At each location, the output of a new notional generator was gradually increased, while interconnector import was decreased, or export was increased as needed to maintain the supply-demand balance. The impact of existing run back schemes was considered in the assessment (where practicable).

Table 6-1: System conditions considered in the assessment of the ability of the South Australian transmission system to accommodate additional generation

System condition	Demand level/ Ratings applied	Wind generation output	Solar generation output	Conventional generators in service
1	Very high demand 3,200 MW/ Summer	Low 9% of capacity	Low 5% of capacity	All
2	High summer demand 2,800 MW/ Summer	Moderate 60% of capacity	Moderate 45% of capacity	Most
3	High winter demand 2,000 MW/ Winter	High 90%	None 0% of capacity	Major generators only
4	Medium demand 1,400 MW/ Spring/ Autumn	High 90%	Low 5% of capacity	Minimum (2 units only)
5	Medium demand 1,400 MW/ Spring/ Autumn	Low 9% of capacity	High 75% of capacity	Major generators only
6	Low overnight demand 1,000 MW/ Winter	High 90% of capacity	None 0% of capacity	Minimum (2 units only)
7	Very low daytime demand 600 MW/ Spring/ Autumn	Low 9% of capacity	Very high 95% of capacity	Minimum (2 units only)
8	Very high demand 3,200 MW/ Summer	0%	0%	All conventional – minus local

At each location, and for each system condition, simulations were stopped when a voltage limitation or a thermal overload was observed on a line or transformer. This was done for all system elements in-service, and again with single credible contingencies considered.

There are several factors that may impact the ability of ElectraNet's transmission network to accommodate significant amounts of new generation in the future:

- The main works for the Heywood interconnector upgrade were completed in July 2016, and 600 MW in available transfer capacity has been released so far. [34]

[34] The full 650 MW capacity is expected to be released later in 2017.

The current capacity is included in the calculation of indicative generator connection capability. Additional incremental upgrades along key transmission corridors, such as those in ElectraNet's proposed Network Capability Incentive Parameter Action Plan (NCIPAP) for the 2018-19 to 2022-23 period, would further alleviate forecast thermal constraints. This would enable the further deployment of generation in South Australia.

- Opportunities to minimise intra-regional transmission constraints by implementing projects that deliver positive net market benefits are assessed by ElectraNet on an ongoing basis. These projects would generally increase the amount of generation that could be connected not considering transient/dynamic issues.
- The changing dispatch behaviour of existing conventional generation also has the potential to change the pattern of power flows on the transmission system. This may alter the capacity of the South Australian transmission network to accommodate increased generation.

The indicative ability of ElectraNet's transmission network and connection points to accommodate new generation (in addition to any existing and committed generation) is summarised in section 6.3. 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. In some cases, it may be feasible to connect larger generators if low cost upgrades can increase the network's transfer capacity. The study does incorporate the impact of committed projects, including those in ElectraNet's 2015–2018 NCIPAP.[35]

6.2 Connection point opportunities for customers

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 provide a reliable supply arrangement. In this context there is already an under-voltage load shedding scheme applied to load at the northern end of the transmission system to allow for secure operation. Any further load connections in this area would obviously exacerbate any under-voltage issues and would therefore be incorporated into this scheme.

Metropolitan electricity demand has grown steadily until recently as a result of residential, commercial and industrial development in the Adelaide metropolitan area. SA Power Networks' distribution network supplies individual electricity customers and the existing Metropolitan 275/66 kV network can accommodate new load connections. . However, recently the loads have either generally remained flat or declining. Depending on their size and location, these load connections may accelerate the need for existing assets to be substantially augmented and/or replaced.

In other regions, ElectraNet has assessed the ability of existing connection points to accommodate the connection of new large loads (section 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 2018–19 10% POE load. The maximum amount of increased demand at a given connection point that could be accommodated across a range of relevant system conditions (including system normal and credible single contingencies) has been determined by comparing network voltage levels to the relevant voltage criteria, for example:

---

35 Available from electranet.com.au.

- 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
- 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 curve of voltage versus power transfer).

The thermal capacity of the transmission network was also applied as a limit to the amount of additional demand that could be supplied at each connection point.

The assessment has the following limitations:

- any additional load at each existing connection point has been assumed to be subject to the same ETC reliability requirements as the connection point. If a less-onerous reliability requirement is acceptable for a new load, it may allow a larger demand increase to be accommodated
- an increase in the load connected at one connection point would directly reduce the additional load that could be accommodated at other connection points, particularly for connection points in close electrical proximity, e.g. if 20 MW of load connected to Berri, then 20 MW couldn’t also be connected to North West Bend.
- an increase in the generation connected at one connection point would directly reduce the additional generation that could be accommodated at other connection points, particularly for connection points in close electrical proximity, e.g. 25 MW of generation connected to Yadnarie then 25 MW of generation couldn’t also be connected to Wudinna.
- the loads and generation 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)
- 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 in the study. In some cases, it may be feasible to connect larger loads if low cost upgrades can increase the available capacity of upstream assets, however ElectraNet notes that a large proportion on the transmission system is now limited by thermal ratings and not substation plant and equipment limits.

6.3 Summary of connection opportunities

An indicative summary of the ability of ElectraNet’s network to accept generator or load connections is given in Table 6-2, which should be read with the limitations described in sections 6.1 and 6.2 in mind. We emphasise that these values only provide a high level indication, as the actual generation or load that can be accommodated often depends on the technical characteristics, operating profile and needs of equipment a customer wishes to connect. If a customer needs to discuss further regarding specific generation or load connections, it is suggested that they contact ElectraNet.

Table 6-2: Indication of available capacity to connect generation and load in 2018-19

Connection point	Additional generation that could be connected (MW) System Condition (see Table 6-1 for description) 1	2	3	4	5	6	7	Additional load that could be connected (MW) 8
Main Grid								
Belalie (275 kV)	400	250	200	200	100	200	400	200
Blyth West (275 kV)	400	300	250	250	450	150	450	200
Brinkworth (275 kV)	450	100	400	300	500	300	500	160
Bungama (275 kV)	400	300	300	250	500	300	500	200
Canowie (275 kV)	200	150	100	100	100	100	400	200
Cherry Gardens (275 kV)	600+	100	400	600+	600+	500	600+	200
Cultana (275 kV)	550	500	450	450	550	450	500	120
Davenport (275 kV)	600+	600+	600+	550	600+	500	600+	150
Mokota (275 kV)	400	250	200	200	100	200	400	200
Mount Lock (275 kV)	200	150	100	100	150	100	450	200
Robertstown (275 kV)	300	550	500	550	100	500	600+	200
South East (275 kV)*[36]	600+	600+	600+	600+	600+	600+	600+	140
Tailem Bend (275 kV)*	600+	600+	600+	600+	600+	550	600+	200
Templers West (275 kV)	350	250	200	200	400	200	400	110
Tungkillo (275 kV)*	600+	600+	600+	600+	600+	500	600+	200
Eastern Hills								
Angas Creek (132 kV)*	150	150	100	100	100	100	100	70
Cherry Gardens (132 kV)*	100	100	100	150	150	150	150	100
Kanmantoo (132 kV)*	50	50	50	50	50	50	50	80
Mannum (132 kV)*	150	150	100	100	100	100	100	50
Mobilong (132 kV)*	300	250	300	300	300	250	250	40
Mount Barker (132 kV)*	250	250	150	250	250	200	200	120
Mount Barker South (275 kV)*	600+	600+	350	600+	600+	500	600+	200
Eyre Peninsula								
Cultana (132 kV)	200	200	200	150	200	150	200	40
Port Lincoln (132 kV)	50	25	25	0	75	0	75	<5
Stony Point (132 kV)	25	25	25	25	25	25	25	80
Whyalla Central (132 kV)	150	50	50	150	150	150	150	40
Wudinna (132 kV)	50	25	25	0	75	0	75	<5

[36] * This node is on an interconnector flow path - subject to co-optimization and constraints.

Connection point	Additional generation that could be connected (MW)							Additional load that could be connected (MW)
	System Condition (see Table 6-1 for description)							
	1	2	3	4	5	6	7	8
Yadnarie (132 kV)	50	25	25	0	75	0	75	10
Mid North								
Ardrossan West (132 kV)	75	25	50	25	75	50	50	40
Baroota (132 kV)	0	0	<10	0	0	<10	0	<5
Brinkworth (132 kV)	250	250	200	150	300	150	250	150
Bungama	150	150	100	50	200	50	150	20
Clare North (132 kV)	150	150	100	100	150	75	150	100
Dalrymple (132 kV)	75	25	50	25	75	50	50	20
Dorrien (132 kV)	150	150	150	150	100	100	100	60
Hummocks (132 kV)	100	25	75	25	75	50	50	40
Kadina East (132 kV)	100	25	75	25	75	50	50	40
Robertstown (132 kV)*	250	150	300	250	350	200	150	40
Templers West (132 kV)	100	100	150	100	100	100	100	60
Waterloo (132 kV)*	250	50	75	75	150	50	200	40
Riverland								
Monash (132 kV)*	150	150	150	300	300	100	50	20
North West Bend (132 kV)*	150	150	150	300	300	100	50	20
South East								
Blanche (132 kV)	100	25	0	0	100	0	75	30
Keith (132 kV)*	50	50	25	0	25	75	25	20
Kincraig (132 kV)*	75	50	50	0	25	50	25	20
Mt Gambier (132 kV)	100	25	25	0	100	25	75	30
Penola West (132 kV)*	50	25	50	0	25	50	25	20
Snuggery (132 kV)	75	25	50	0	150	25	75	40
South East (132 kV)*	150	25	0	0	100	0	75	50
Tailem Bend (132 kV)*	150	25	150	100	150	200	200	70
Upper North								
Davenport (132 kV)	100	75	100	100	100	100	100	50
Leigh Creek South (132 kV)	0	0	<10	0	0	<10	0	<5
Mt Gunson (132 kV)	50	50	50	50	50	50	50	0
Neuroodla (132 kV)	0	0	<10	0	0	<10	0	<5
Pimba (132 kV)	50	50	50	50	50	50	50	0

6.4 Proposed new connection points

A new connection point is proposed by SA Power Networks in the Mid North to meet localised growing demand (Table 6-3).

Table 6-3: Proposed new connection points for generators and customers

Connection point	Planning region	Project year	Connection voltage (kV)	Scope of work
Gawler East	Mid North	2022 (subject to request from SA Power Networks	132	Turn the Para to Roseworthy 132 kV line in/out at Gawler East and establish a 132 kV bus SA Power Networks to establish a single-transformer 132/11 kV distribution substation Refer to section 8.4.2 for more details

6.5 Current and potential transmission connection hubs

ElectraNet endeavours to develop connections for new generators and loads to provide a cost effective, 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 minimises network constraints for the customer, maximises network utilisation, reduces connection costs, and facilitates efficient and sustainable long-term transmission network development.

Using this approach, wind farm developments in the Mid North are connected to balance the loading on the parallel 275 kV lines between Port Augusta and Adelaide is as far as possible. This reduces the likelihood of generation constraints and limitations to power transfer capability in the corridors if power transfer requirements increase in the future.

In response to a connection enquiry, ElectraNet considers the location and configuration of the connection in order to ensure long term efficient use of the shared network. We may recommend that generators and load customers connect to a specific network location if efficient to do so. ElectraNet will also specify the appropriate configuration for that connection. Nodal connection points allow parallel transmission lines to be tied together and new generation to be efficiently placed in the system, to further balance line loadings and maximise thermal transfer capability on the network.

ElectraNet has identified twelve potential connection hubs in the South Australian transmission network (Figure 6-1).

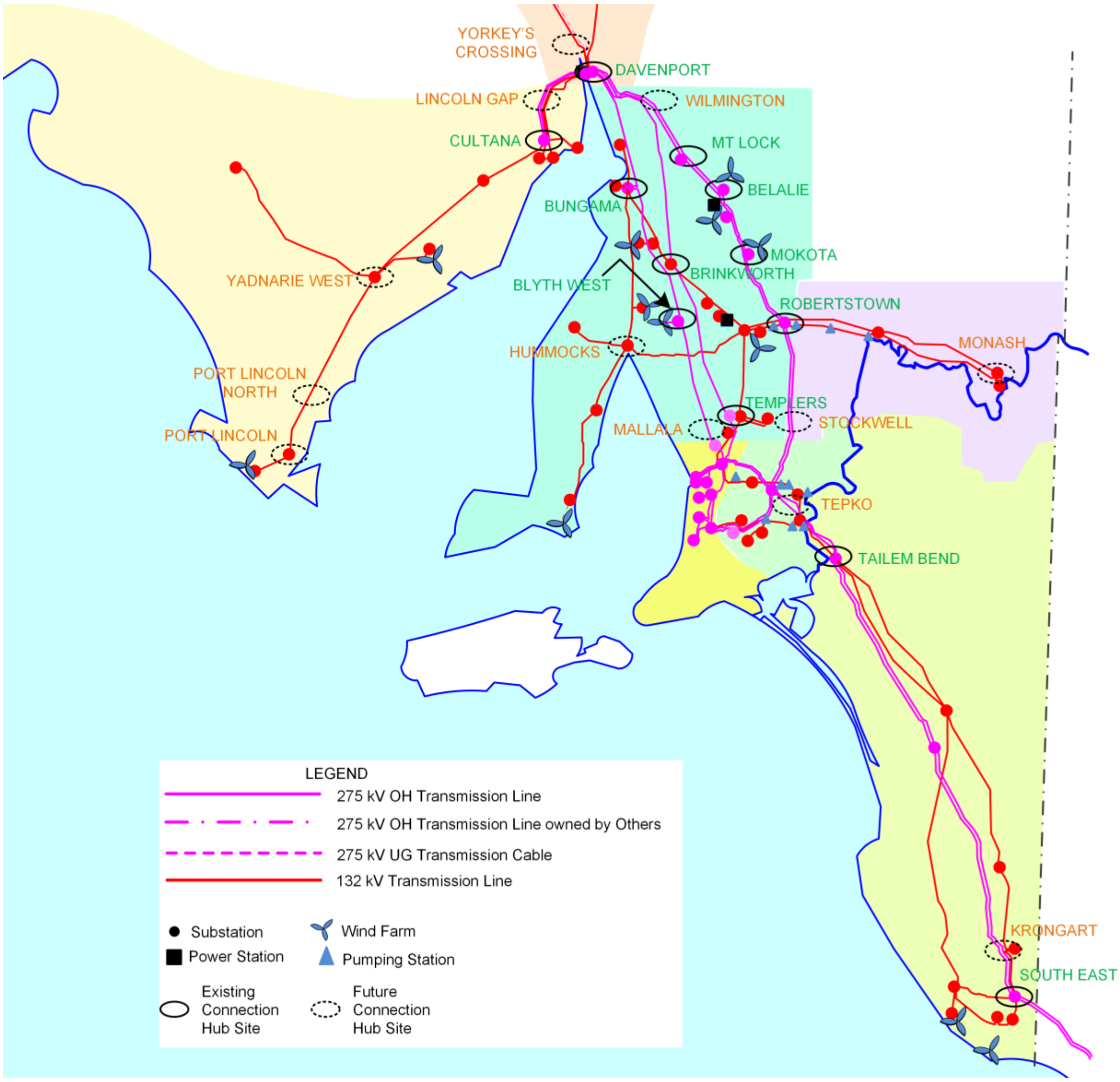

Figure 6-1: Current and possible South Australian future transmission connection hubs

7. Completed, committed and pending projects

This chapter summarises the significant projects to remove network limitations and address asset condition that ElectraNet has completed, committed to and are pending over the last year.

7.1 Recently completed projects

ElectraNet has completed several significant projects to remove network limitations and address asset condition (Table 7-1).

Table 7-1: Projects completed between 1 May 2016 and 31 May 2017

Project description	Region	Project Category	Asset in service
Heywood interconnector upgrade The Heywood interconnector was incrementally augmented to raise nominal transfer limits from ±460 MW to ±600 MW[37]. This was shown to deliver market benefits using the RIT-T. A third 500/275 kV transformer at Heywood terminal station was installed along with series compensation[38] on the South East to Tailem Bend 275 kV lines and the existing 132 kV transmission system was reconfigured between Snuggery, Keith and Tailem Bend	Main Grid/ South East	Augmentation	25/07/2016[39]
SA Water Morgan-Whyalla Pump Station #3 Rebuilt the Morgan to Whyalla pumping station #3 supply site to ensure continued supply reliability to critical water infrastructure	Riverland	Replacement	18/08/2016
SA Water Morgan-Whyalla Pump Station #1 Rebuilt the Morgan to Whyalla pumping station #1 supply site to ensure continued supply reliability to critical water infrastructure	Riverland	Replacement	30/09/2016
Dalrymple Substation Upgrade Installed an additional 25 MVA 132/33 kV transformer and associated switchgear to meet ETC category 2 requirements	Mid North	Connection	1/11/2016
Para SVC Secondary Systems Replaced Para SVC thyristor valves and valve cooling, protection and control systems that had reached their end of life, and installed and integrated a 50 Mvar switched 275 kV reactor, to ensure continued reliable voltage control on South Australia's 275 kV transmission system	Main Grid	Replacement	30/11/2016

[37] A market notice was issued on 5/08/2016 releasing a transfer limit of 600 MW. The next increment of 650 MW is on hold pending review of frequency changes impacts.

[38] Series compensation reduces the "electrical distance" of a transmission line, thereby increasing the maximum possible power transfer over the line.

[39] 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.

Project description	Region	Project Category	Asset in service
Tailem Bend – Keith #2 132 kV line insulator replacement All porcelain disc insulator assemblies that had reached end of life to ensure continued 132 kV line reliability	South East	Refurbishment	20/01/2017

7.2 Committed projects

Committed projects are projects where the RIT-T has been completed (where required), and the ElectraNet Board has given approval. ElectraNet is currently undertaking several committed projects which are expected to be completed in the near future (Table 7-2).

Table 7-2: Committed projects

Project description	Region	Project Category	Expected Service Date
SA Water Mannum-Adelaide Pump Station #2 Rebuild the Mannum to Adelaide pumping station #2 supply site to ensure continued supply reliability to critical water infrastructure	Eastern Hills	Replacement	June 2017
SA Water Morgan-Whyalla Pump Station #4 Rebuild the Morgan to Whyalla pumping station #4 supply site to ensure continued supply reliability to critical water infrastructure	Mid North	Replacement	September 2017
SA Water Mannum-Adelaide Pump Station #3 Rebuild the Mannum to Adelaide pumping station #3 supply site to ensure continued supply reliability to critical water infrastructure	Eastern Hills	Replacement	September 2017
Brinkworth – Mintaro 132 kV line remediation and insulator replacement Porcelain disc insulator assemblies that have reached end-of-life will be replaced along with defective poles and cross arms, to ensure continued 132 kV line reliability	Mid North	Refurbishment	November 2017
Tailem Bend Substation Upgrade Improve the circuit breaker arrangement to reduce constraints on the Heywood interconnector and improve network security and reliability	Main Grid	Security / Compliance	November 2017
SA Water Mannum-Adelaide Pump Station #1 Rebuild the Mannum to Adelaide pumping station #1 supply site to ensure continued supply reliability to critical water infrastructure	Eastern Hills	Replacement	November 2017
Various unit asset replacements 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 to ensure continued asset reliability	Various	Replacement	April 2018

Project description	Region	Project Category	Expected Service Date
Para-Brinkworth-Davenport Hazard Mitigation Replace load-releasing cross arms and all porcelain disc insulators, to ensure continued 275 kV line reliability	Main Grid	Refurbishment	December 2018

The following section provides additional detail for our only current major committed project (greater than $5 million expenditure at a single site): the Tailem Bend Substation Upgrade (section 7.2.1).

Estimated project costs quoted in this chapter are presented in 2017 dollar values. Cost estimates are provided as a range to 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.

7.2.1 Tailem Bend substation upgrade

Scope of work: Extend Tailem Bend substation to accommodate an additional 275 kV diameter with two circuit breakers, associated plant and secondary systems, and rearrange 275 kV line exits

Estimated cost: $9-10 million

Project category: Security/Compliance

Timing: November 2017

Project status: Committed, construction in progress

The Heywood Interconnector Upgrade project has increased the capacity of the interconnector from a nominal 460 MW to 600 MW, with the target capacity of 650 MW anticipated to be released by the end of 2017. This will result in a greater reliance on the performance of the substations that connect South Australia to the National Electricity Market via the Heywood Interconnector.

Tailem Bend substation has a 275 kV section that is not laid out in a ‘circuit breaker and a half’ topology and the existing topology significantly constrains the interconnector under certain conditions.

The planned layout will minimise the impact of these constraints on NEM participants and improve the quality, reliability and security of supply of prescribed transmission services. A similar upgrade was completed at South East substation in December 2015.

7.3 Pending projects

ElectraNet does not currently have any pending projects, meaning projects which have passed the RIT-T but are not yet fully committed.

8. Transmission Network Development Plan

ElectraNet and SA Power Networks 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, according to Rule requirements. The analyses and resulting development plan (presented in this chapter) are designed to address projected limitations on the South Australian transmission network over a 10-year period. These developments include projects to meet various needs, such as to:

- augment capacity to meet increasing connection point demand (if relevant)
- maintain compliance with Rules obligations
- improve system security and operational flexibility
- maintain adequate asset condition
- provide net market benefits by minimising transmission network constraints.

This development plan has been based on forecast demand (section 5.2) and diversity factors have been applied as appropriate in each case for planning the Main Grid and regional corridors. In the analysis, Main Grid and regional meshed networks are planned to meet 10% POE demands with wind farm outputs set to 9.4% 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).

8.1 Planning scenario and sensitivities

A central planning scenario has been developed and evaluated as part of ElectraNet's planning process. A number of sensitivities have also been applied, to represent different assumptions about the future development of demand and generation in South Australia. The scenario together with the sensitivities is intended to represent a range of credible potential futures.

The planning scenario and sensitivity assumptions have been characterised (Table 8-1) and the potential new loads and generation connections over the next ten years are graphically represented in Figure 8-1.

Table 8-1: Characteristics and assumptions of ElectraNet's planning scenario

Characteristic	Planning scenario
Connection point maximum demand forecasts	ElectraNet's 2017 Connection Point Forecasts Report[40] SA light load scenario projected by scaling embedded rooftop solar PV at each connection point to achieve AEMO's 2016 NEFR 90% POE minimum demand forecast
SA transmission system coincident maximum demand forecast	AEMO's 2016 NEFR 10% POE maximum demand forecast
New load connections	As shown in Figure 8-1
New conventional generators	
New renewable generators	

[40] Available from electranet.com.au.

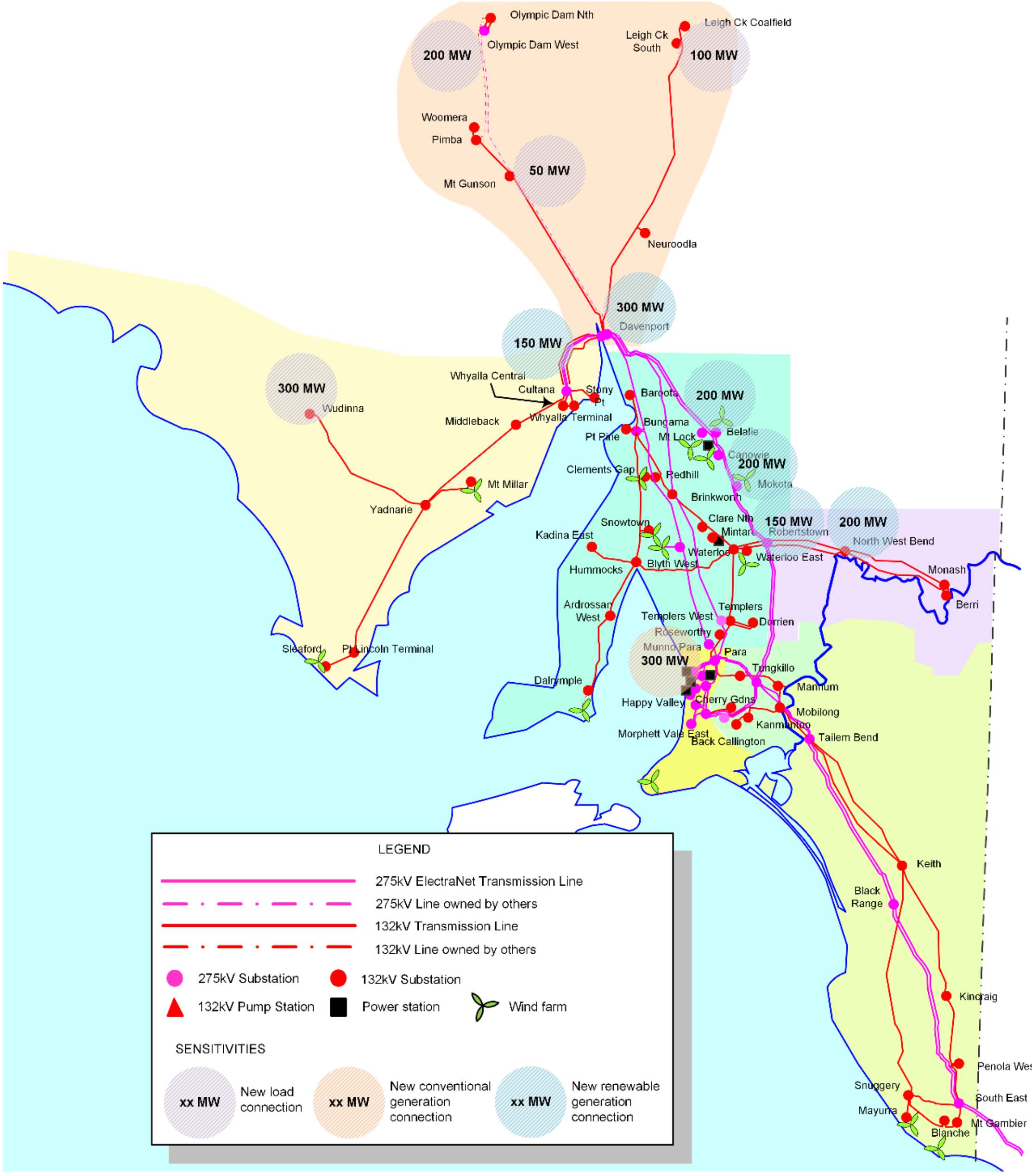

Figure 8-1: Assumptions and sensitivities considered in ElectraNet's planning process, including potential future step load increases, generator retirements, and renewable generator connections

8.2 Summary of planning outcomes

Analysis of the planning scenario and sensitivities led to a range of high level outcomes or project recommendations (Table 8-2). Detailed outcomes, or potential projects required to support the sensitivities, are covered in sections 8.3 to 8.9.

Table 8-2: Summary of planning outcomes

Planning focus	Key outcomes
Emerging system security issues (e.g. system inertia, system strength)	System security issues that may arise from low levels of system inertia and declining levels of system strength (as projected in AEMO's 2016 National Transmission Network Development Plan) could be addressed by: • establishing a new interconnector between South Australia and the Eastern States to address emerging system security issues and provide net market benefits, as is being considered by the South Australian Energy Transformation RIT-T • installing plant such as synchronous condensers A grid-scale battery energy storage system is proposed for connection at Dalrymple to help improve system security and reliability.
Connection points	The existing network support arrangement at Port Lincoln expires in December 2018. A RIT-T has been commenced to determine the most cost effective way of continuing to meet the required reliability standard at Port Lincoln beyond that date. The outcome of this investigation could be significant network investment on the Eyre Peninsula (e.g. a new double circuit line from Cultana to Yadnarie to Port Lincoln) and/ or a new network support arrangement.
Market benefit opportunities	A range of market benefit driven projects is proposed to reduce the impact of constraints and increase the capability of the transmission network, providing net market benefits.
Maximum demand	South Australia's transmission network is projected to be adequate to supply forecast maximum demand for the duration of the planning period. Augmentation may be needed to supply future significant individual load connections, particularly in the Upper North region, depending on their size and location.
Minimum demand	As the minimum demand supplied by the transmission network is forecast to decrease, a series of 275 kV reactor investments (or similar) is needed to prevent voltage levels from exceeding equipment ratings if an unplanned contingency event was to occur at times of low demand.
Maximum fault levels	Fault levels are forecast to remain within design and equipment limits for the duration of the planning period.
Emergency control schemes	ElectraNet and AEMO are working together to develop a special protection scheme that will reduce the chance of islanding following a non-credible simultaneous loss of multiple generators within South Australia

8.3 Emerging system issues

South Australia has world leading penetration levels of intermittent renewable energy generation sources. The non-synchronous nature of the renewable generation, combined with a decreased dispatch of synchronous generation, poses unique challenges for the secure and stable operation of the power system.

We have developed a number of proposed projects to address these emerging challenges (Figure 8-2, and sections 8.3.1 to 8.3.3).

ElectraNet envisages that all of these projects will have a material impact on inter-regional transfer.

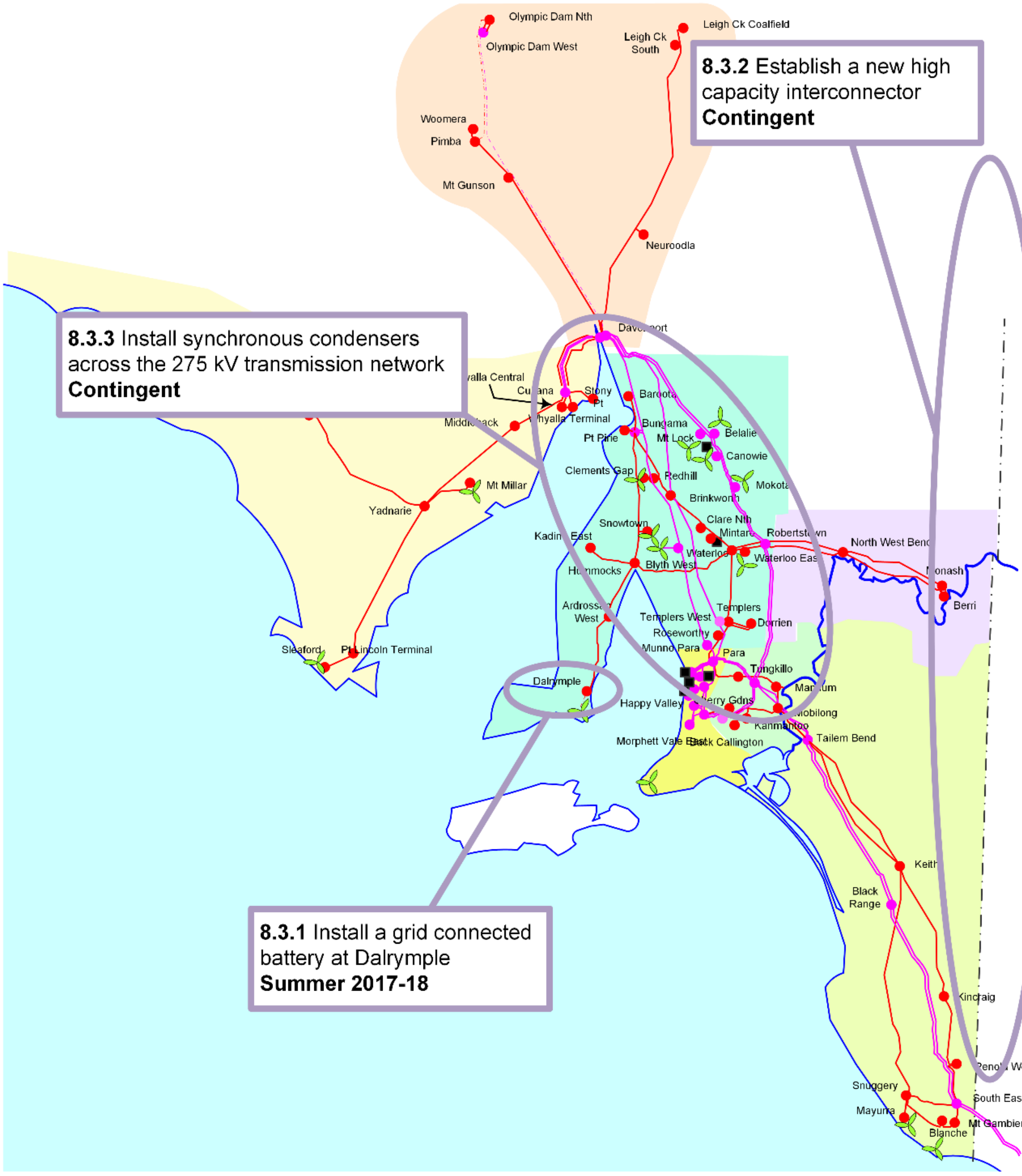

Figure 8-2: Proposed projects to address emerging challenges to the secure and stable operation of the power system

8.3.1 Install a grid-connected battery at Dalrymple (ESCRI-SA)

Scope of work: Install a nominal 30 MW, 8 MWh battery energy storage system at Dalrymple along with associated site establishment, high voltage switchgear, secondary systems and telecommunications equipment

Estimated cost: $25 - 35 million (including regulated and non-regulated component)

Project category: Augmentation

Timing: Summer 2017-18

Project status: Subject to further analysis and approvals

Project need and option analysis:

The identified need for this project is a proof of concept demonstration that utility scale battery storage can support the integration of renewable energy.

The ESCRI-SA project will capture both regulated and non-regulated benefits.

The purpose of the regulated component is to demonstrate:

- islanded operation during contingency periods, with local demand around Dalrymple supplied by the Wattle Point wind farm and local rooftop solar alone, balanced by the battery storage. This will improve local supply reliability and result in learnings applicable to other systems with 100% intermittent renewable generation
- the application of fast acting battery storage to providing essential system security services such as Fast Frequency Response that can address system security risks associated with a high Rate of Change of Frequency.

The regulated cost component is less than $6 million, which is exceeded by the associated customer benefits.

Non-regulated services provided by the battery will be dispatched by the battery operator.

The project is also expected to deliver substantial knowledge sharing benefits.

8.3.2 New high capacity interconnector

Scope of work: Construct a new high capacity interconnector between South Australia and the Eastern States

Estimated cost: $250 - 500 million (South Australian component only)

Project category: Augmentation

Timing: Uncertain

Project status: Contingent – refer to Table for trigger

Project need and option analysis:

On 7 November 2016, ElectraNet commenced the South Australian Energy Transformation RIT-T by publishing a PSCR.

As required by the Rules, the RIT-T is directed at meeting an identified need, which in this case is defined as:

- facilitating greater competition in the wholesale electricity market, to lower dispatch costs and consequently wholesale electricity prices, particularly in South Australia (‘market need’)

- providing appropriate security of supply, including inertia, frequency response and system strength services in South Australia ('security need')
- facilitating the transition to lower carbon emissions and the adoption of new technologies ('emissions need').

Options that were highlighted in the PSCR include new interconnectors between South Australia and the Eastern States, supported by measures within the South Australian system to address the needs for system strength and inertia. The RIT-T is also considering alternative solutions that do not involve an interconnector, such as demand response, generation options, battery storage and other solutions.

Both the timing and scope of this project are subject to further analysis and are uncertain at this point in time.

Table 8-3: Options considered for a new high capacity interconnector

Option	Description	Comment	Estimated cost ($ Million)
1	Central SA to Victoria interconnector (nominally Tungkillo to Horsham, and beyond)	Construct a new line and associated works Consideration will be given (without limitation) to HVAC, HVDC, single circuit and double circuit options, including staging of development	500 – 1,000 (ElectraNet and AusNet Services)
2	Mid North SA to NSW interconnector (nominally Robertstown to Buronga, and beyond)	Construct a new line and associated works Consideration will be given (without limitation) to 275 kV HVAC, 330 kV HVAC, HVDC, single circuit and double circuit options, including staging of development	500 – 1,500 (ElectraNet and TransGrid)
3	Northern SA to NSW interconnector (nominally Davenport to Mt Piper)	Construct a new high capacity line(s) and associated works Consideration will be given (without limitation) to HVAC and HVDC options, including staging of development	1,500 – 2,000 (ElectraNet and TransGrid)
4	Northern SA to Queensland interconnector (nominally Davenport to Bulli Creek)	Construct a new high capacity line(s) and associated works Consideration will be given (without limitation) to HVAC and HVDC options, including staging of development	2,000 – 2,500 (ElectraNet and Powerlink)
5	Non-network solutions	A variety of non-network capabilities to provide fast frequency response, inertia and system strength; e.g. large-scale batteries, demand management, generation	To be informed via submissions to the PSCR

8.3.3 Install synchronous condensers

Scope of work: Upgrade existing protection devices and install six synchronous condensers at selected locations across the 275 kV transmission network

Estimated cost: $60 - 80 million

Project category: Security/Compliance

Timing: Uncertain

Project status: Contingent – refer to Table 4 for trigger

Project need and option analysis:

AEMO has identified that the operation of large high voltage power systems such as South Australia at low fault levels can result in the conditions of the power system being unstable due to factors such as:[41]

- manufacturers' design limits on power electronic interfaced devices such as wind turbines and SVCs. Operation of these devices outside their minimum design limits could give rise to generating systems' instability and consequent disconnection from the grid
- protection systems which rely on measurement of current (excluding differential protection) or current and voltage during a fault to achieve two basic requirements – selectivity (that is, to operate only for conditions for which the system has been installed) and sensitivity (that is, to be sufficiently sensitive to faults on the equipment it is protecting)
- inability to control voltage during normal system and market operations such as switching of transmission lines or transformers, switching reactive plant (capacitors and reactors), transformer tap changing, and routine variations in load or generation.

AEMO's preliminary analysis of 13 November 2016 concluded that two large synchronous generating units, or combinations of smaller synchronous generating units, are required to be online in South Australia to ensure a secure operating state as defined in clause 4.2.2 of the Rules. AEMO also concluded that this may demonstrate the existence of an NSCAS gap.

AEMO plans to further investigate this issue and publish a report in 2017 in relation to this requirement, and will collaborate with ElectraNet to confirm the existence, size, and trigger date of the NSCAS gap.[42, 43]

The requirement for the project is to maintain minimum fault levels in South Australia for foreseeable operating conditions above a level that is sufficient to ensure that:

- power electronic interfaced devices such as wind turbines and static Var compensators can remain stable

[41] AEMO, SA System Strength, available at www.aemo.com.au/~/media/Files/Media_Centre/2016/SA-System-Strength.pdf.
[42] AEMO, 2016 NTNDP, p 98, available at aemo.com.au.
[43] AEMO invoked this operational requirement on 26 April 2017.

- synchronous machines can remain stable and provide the fault current required for the operation of other plant
- protection systems can adequately function
- voltage can be maintained during normal system and market operations including switching transformers, transmission lines and reactive plant, transformer tap changing, and routine variations in load or generation.

Both the timing and the scope of this project, and therefore the transmission requirements, are uncertain at this point in time.

Confirmation of the existence, size, and trigger date of a potential NSCAS gap, or other requirement for ElectraNet to address a system strength requirement in the South Australian region, will determine the need and timing for this project.

8.4 Connection points

ElectraNet annually compares connection capability against forecast connection point demand, considering the redundancy requirements specified for each connection point in the ETC (Table A-1 in Appendix A). This occurs in the context of a series of regular joint planning meetings with SA Power Networks, in which connection point projects are considered, proposed, and planned.

Over the 10-year planning period, only one connection point – Port Lincoln – requires action to ensure that the Category 3 reliability standard continues to be met (section 8.4.1). This action is not driven by an increase in demand, but rather by the expiry of the existing network support arrangement.

In addition, one new connection point is proposed, at Gawler East (8.4.2), subject to local land development activity and advice from SA Power Networks regarding required timing. The locations of these projects are shown in Figure 8-3.

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

Figure 8-3: Connection point projects

8.4.1 Replace Eyre Peninsula 132 kV transmission lines

Scope of work:	Build new double circuit 132 kV or 275 kV lines from Cultana to Yadnarie and from Yadnarie to Port Lincoln
Estimated cost:	$200-$550 million[44]
Project category:	Augmentation (Contingent)
Timing:	About 2022
Project status:	Proposed

44 Based on the range of options currently being considered

Project need and option analysis:

The existing network support arrangement that enables the category 3 ETC reliability requirements to be met at Port Lincoln substation expires in December 2018. ElectraNet has also assessed that significant components of the Whyalla to Yadnarie and the Yadnarie to Port Lincoln 132 kV lines require replacement in the 2018-19 to 2022-23 period.

ElectraNet has developed five potential options to meet this need (Table 8-4). Option 1 would directly address the identified need by replacing the relevant line components and establishing a new network support agreement, whereas the other options would provide additional capacity, reliability and market benefits.

We have commenced a RIT-T to determine the most economical way of continuing to meet or exceed the ETC requirements at Port Lincoln beyond December 2018. A PSCR was published in April 2017, and closes for consultation on 21 July 2017.

ElectraNet has included Option 1 in the capital program in our 2018-19 to 2022-23 revenue proposal to the AER. The revenue proposal also includes a contingent project to provide the additional revenue that will be needed if the RIT-T demonstrates that any of the other options is more economical.

Table 8-4: Options considered for Eyre Peninsula 132 kV line replacement

Option	Description	Comment	Estimated cost ($ million)
1	Continue network support arrangement at Port Lincoln and component replacement works on the existing 132 kV single-circuit transmission line	This option would also have significant operating costs for ongoing network support at Port Lincoln	80
2	Construct a new double circuit 132 kV transmission line following a Cultana to Yadnarie and Yadnarie to Port Lincoln route	We will investigate the potential benefits of additional emergency restoration measures that may include network support We will also consider the potential benefits of upgrading the Davenport to Cultana 275 kV transmission lines to further improve supply reliability and security to the Eyre Peninsula	200-300
3	Construct two single circuit 132 kV transmission lines following separated routes between Cultana and Port Lincoln	We will also consider the potential benefits of upgrading the Davenport to Cultana 275 kV transmission lines to further improve supply reliability and security to the Eyre Peninsula	200-350

Option	Description	Comment	Estimated cost ($ million)
4	Construct a double circuit 275 kV transmission line following a Cultana to Yadnarie and Yadnarie to Port Lincoln route	New lines to be operated initially at 132 kV We will investigate the potential benefits of additional emergency restoration measures that may include network support We will also consider the potential benefits of upgrading the Davenport to Cultana 275 kV transmission lines to further improve supply reliability and security to the Eyre Peninsula	280-380
5	Construct two single circuit 275 kV transmission lines following separated routes between Cultana and Port Lincoln	New lines to be operated initially at 132 kV We will also consider the potential benefits of upgrading the Davenport to Cultana 275 kV transmission lines to further improve supply reliability and security to the Eyre Peninsula	400-550

8.4.2 Establish a new connection point at Gawler East

Scope of work: Cut into the Para to Roseworthy 132 kV line and create a 132 kV connection point for a new 132/66/11 1x25 MVA transformer substation

Estimated cost: <$5 million (132 kV bus and connection point)

Project category: Connection

Timing: November 2022

Project status: Proposed

Project need and option analysis:

The new Gawler East 132 kV connection point is planned to support “greenfields” residential development in the area. The development site allows for up to 2,450 allotments and a commercial centre with an ultimate residential demand estimated at 22 MVA and 2.5 MVA of commercial load. There are also future plans to develop the adjacent greenfields region (Concordia), with more than double the potential ultimate demand increase. Residential development commenced at Gawler East in 2014, with an anticipated requirement for the new 132/11 kV zone substation by the end of 2022.

SA Power Networks have advised that they plan to work with ElectraNet to commence a Regulatory Investment Test for Distribution (RIT-D) assessment by issuing a Non-Network Options Report (NNOR) at a future date.

A suitable ElectraNet 132 kV transmission line traverses the planned greenfields residential development region. Compared to the alternative of extending SA Power Networks’ 66 kV network, a new connection point is better placed both environmentally (as the 132 kV line already exists), and in terms of total cost to South Australian distribution customers (as the total cost is lower), to supply SA Power Networks’ proposed 25 MVA 11 kV substation.

The preferred option will be determined by the outcome of the RIT-D assessment (Table 8-5).

Table 8-5: Options considered for a new Gawler East connection point

Option	Description	Comment	Estimated cost ($ Million)
1	Build 132 kV bus to provide supply to a 132/11 kV substation	ElectraNet to provide 132 kV bus and connection point; SA Power Networks to own 1x25 MVA 132/11 kV transformer	11-14 (ElectraNet and SA Power Networks)
2	Build a 132/11 kV substation with a single 25 MVA transformer	ElectraNet to own 1x25 MVA 132/11 kV transformer and provide an 11 kV connection point	11-14 (ElectraNet and SA Power Networks)
3	Distribution solution: SA Power Networks to construct a new 66 kV line and 66/11 kV zone substation	This option is expensive and is excluded from further consideration	16-34 (SA Power Networks)

8.5 Market benefit opportunities

ElectraNet monitors congestion on the South Australian transmission network. We also consider information regarding future likely generator and load connections, along with AEMO's most recent NTNDP, to predict new constraints that may develop in future years.

Over the next year, we plan to complete projects that form part of our 2014-15 to 2017-18 Network Capability Incentive Parameter Action Plan (NCIPAP, sections 8.5.1 and 8.5.2). We have also proposed a full range of market benefit driven projects, up to the maximum allowance for NCIPAP projects, and one further market benefit project for the 2018-19 to 2022-23 regulatory control period (sections 8.5.3 to 8.5.9). The locations of these projects are illustrated in Figure 8-4.

8.5.1 Uprate Riverland 132 kV lines

Scope of work: Uprate the Robertstown to North West Bend No. 2 132 kV line and the North West Bend to Monash No. 2 132 kV line from 80 °C design clearances to 100 °C design clearances

Estimated cost: <$5 million

Project category: NCIPAP

Timing: June 2017

Project status: Committed

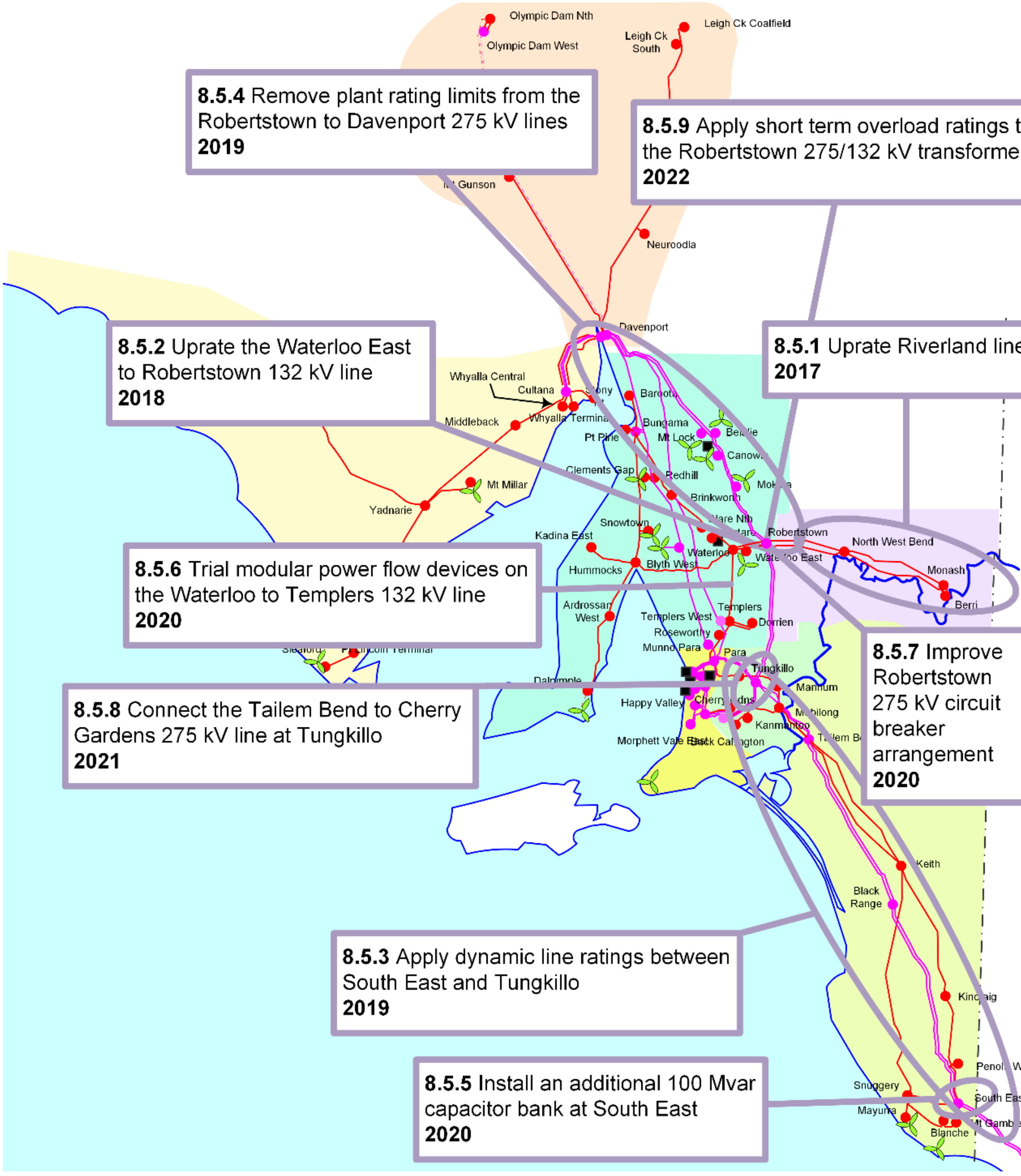

Figure 8-4: Committed and proposed market benefit projects

Project need and option analysis:

This project is in ElectraNet's NCIPAP for the 2014-15 to 2017-18 period. It will increase the transfer capacity of selected Riverland 132 kV lines that connect to the Murraylink interconnector, enabling increased power export to Victoria under high Riverland demand by about 24 MW. It will also increase the capability of South Australian wind farms to export power under high wind generation conditions at all times of the year. This will be achieved by increasing the design operating temperatures of the selected lines, from 80°C design clearances to 100°C design clearances.

ElectraNet envisages that this project will impact inter-regional transfer.

8.5.2 Uprate the Waterloo East to Robertstown 132 kV line

Scope of work: Uprate the Waterloo East to Robertstown 132 kV line from 80°C design clearances to 100°C design clearances

Estimated cost: <$5 million

Project category: NCIPAP

Timing: June 2018

Project status: Planned

Project need and option analysis:

This project is in ElectraNet's NCIPAP for the 2014-15 to 2017-18 period. Increasing the transfer capacity of this line will reduce congestion on the Murraylink interconnector, enabling increased power export to Victoria under high Riverland demand by about 37 MW. It will also increase the capability of South Australian wind farms to export power under high wind generation conditions at all times of the year. This will be achieved by increasing the design operating temperatures of the selected lines, from 80°C design clearances to 100°C design clearances.

ElectraNet envisages that this project will impact inter-regional transfer.

8.5.3 Apply dynamic ratings to transmission lines between South East and Tungkillo

Scope of work: Apply dynamic ratings to the Tailem Bend to Tungkillo, Tailem Bend to Cherry Gardens, South East to Tailem Bend No. 1, and South East to Tailem Bend No. 2 275 kV lines and to the Tailem Bend to Mobilong 132 kV line

Estimated cost: <$5 million

Project category: Proposed for 2018-19 to 2022-23 NCIPAP

Timing: June 2019

Project status: Proposed

Project need and option analysis:

This project is in ElectraNet's proposed NCIPAP for the 2018-19 to 2022-23 period. Increasing the dynamic rating of these lines will reduce congestion on the Heywood interconnector, enabling increased power transfers to and from Victoria by about 31 MW. This is the average improvement expected from improving the ratings of the Tailem Bend to Tungkillo 275 kV line summer ratings by 47 MW and the spring/autumn ratings by 15 MW, up to the 650 MW Heywood interconnector limit.

ElectraNet envisages that this project will impact inter-regional transfer, by increasing the thermal transfer capacity across the Heywood interconnector.

8.5.4 Remove plant rating limits from the Robertstown to Davenport 275 kV lines

Scope of work:	Remove and replace plant that are rated lower than the design capability of the conductors on the 275 kV lines between Robertstown and Davenport, to release further transfer capacity
Estimated cost:	<$5 million
Project category:	Proposed for 2018-19 to 2022-23 NCIPAP
Timing:	June 2019
Project status:	Proposed

Project need and option analysis:

This project is in ElectraNet's proposed NCIPAP for the 2018-19 to 2022-23 period. Increasing the rating of this line will alleviate forecast congestion between the northern region of SA, where AEMO has identified that 1,400 MW of renewable generation may connect by 2020-21, and the Adelaide metropolitan region.

This will increase the capability of the Davenport to Robertstown 275 kV lines by at least 115 MVA under summer ratings, and by more under spring/autumn and winter ratings.

ElectraNet envisages that this project will impact intra-regional transfer, but not inter-regional transfer.

8.5.5 Install an additional 100 Mvar 275 kV capacitor bank at South East

Scope of work:	Install an additional 100 Mvar 275 kV switched capacitor at South East substation
Estimated cost:	<$5 million
Project category:	Proposed for 2018-19 to 2022-23 NCIPAP
Timing:	June 2021
Project status:	Proposed

Project need and option analysis:

This project is in ElectraNet's proposed NCIPAP for the 2018-19 to 2022-23 period. Installing this capacitor will alleviate forecast congestion on the Heywood interconnector due to voltage stability limits.

This will increase the 'firmness' of Heywood interconnector's notional 650 MW capability, providing increased availability of the full capability.

ElectraNet envisages that this project will impact inter-regional transfer, by enabling voltage stability to be maintained at increased transfer levels across the Heywood interconnector.

8.5.6 Trial modular power flow control elements to relieve congestion

Scope of work: Install modular power flow control elements to relieve congestion on the Waterloo to Templers 132 kV line, and uprate the parallel Robertstown to Tungkillo and Robertstown to Para 275 kV lines as well as the Templers to Roseworthy 132 kV line

Estimated cost: $3-6 million

Project category: Proposed for 2018-19 to 2022-23 NCIPAP

Timing: June 2020

Project status: Proposed

Project need and option analysis:

This project is in ElectraNet's proposed NCIPAP for the 2018-19 to 2022-23 period. Uprating the relevant 275 kV and 132 kV lines and installing the modular power flow control elements on the Waterloo to Templers 132 kV line will reduce forecast congestion between the Adelaide metropolitan region and the northern region of SA, where AEMO has identified that 1,400 MW of renewable generation may connect by 2020-21.

This will increase the transfer capacity between the northern region of SA and the Adelaide metropolitan region by about 17 MW. During network conditions that have high flows on the 132 kV lines relative to the 275 kV lines, the dynamic line impedance devices are expected to alleviate constraints by more than 17 MW.

ElectraNet envisages that this project will impact intra-regional transfer, but not inter-regional transfer.

8.5.7 Improve Robertstown circuit breaker arrangement

Scope of work: Install a single 275 kV circuit breaker and associated equipment (including isolators, current transformer and protection) between the 275 kV buses at Robertstown

Estimated cost: $5-8 million

Project category: Security/Compliance

Timing: June 2020

Project status: Proposed

Project need and option analysis:

The present layout of Robertstown substation poses operational challenges. During planned outages of certain items of plant, it is possible for an unplanned 275 kV line outage to electrically separate the 275 kV buses. This would result in large power flows travelling from one 275 kV bus, through one Robertstown 275/132 kV transformer, and back up the other Robertstown 275/132 kV transformer to the other 275 kV bus. To guard against the risk of transformer overload during such times, the Murraylink interconnector needs to be significantly constrained and generation north of Robertstown may need to be constrained to limit potential post-contingency flows.

This project will reduce the costs to end-use customers under outage conditions, by reducing the constraints that are currently unavoidable due to the existing 275 kV circuit breaker arrangement at Robertstown.

ElectraNet envisages that this project will impact inter-regional transfer, by alleviating constraints on Murraylink interconnector during planned outages at Robertstown substation.

8.5.8 Connect the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo

Scope of work:	Populate one additional diameter at Tungkillo to connect the Tailem Bend to Cherry Gardens 275 kV line, to improve inter-regional transfer capacity
Estimated cost:	$3-6 million
Project category:	Proposed for 2018-19 to 2022-23 NCIPAP
Timing:	June 2020
Project status:	Proposed

Project need and option analysis:

This project is in ElectraNet's proposed NCIPAP for the 2018-19 to 2022-23 period. Tying in the Tailem Bend to Cherry Gardens 275 kV line is expected to alleviate voltage limitations on the Heywood interconnector, allowing the 650 MW operational limit to be available more often.

At times when voltage limits restrict flows on the Heywood interconnector, this project will increase the interconnector's transfer capability by 10 MW.

ElectraNet envisages that this project will impact inter-regional transfer.

8.5.9 Apply short term overload ratings to the Robertstown 275/132 kV transformers

Scope of work:	Install transformer management relays and bushing monitoring equipment to enable the application of short term ratings to the Robertstown 275/132 kV transformers
Estimated cost:	<$5 million
Project category:	Proposed for 2018-19 to 2022-23 NCIPAP
Timing:	June 2022
Project status:	Proposed

Project need and option analysis:

This project is in ElectraNet's proposed NCIPAP for the 2018-19 to 2022-23 period. Uprating the Robertstown 275/132 kV transformers will reduce forecast congestion between the Riverland and the northern region of SA, where AEMO has identified that 1,400 MW of renewable generation may connect by 2020-21.

This will increase the ratings of the Robertstown transformers by 48 MVA, alleviating forecast constraints on Murraylink interconnector.

ElectraNet envisages that this project will impact inter regional transfer, by improving the export capability of Murraylink interconnector.

8.6 Maximum demand

Maximum demands on South Australia's electricity transmission network typically occur during heatwave conditions in summer (section 5.1).

We have assessed the ability of the network to deliver maximum demand without overload with all system elements in service, and allowing for any one item of plant to be out of service.

As a result, we are projecting that the transmission network is adequate to supply forecast maximum demand for the duration of the 10-year planning period. However, two projects to reinforce 132 kV transmission lines may be needed if potential significant spot loads connect in certain locations (Figure 8-5, with details in sections 8.6.1 and 8.6.2).

8.6.1 Upper North region eastern 132 kV line reinforcement

Scope of work:	Uprate or rebuild the Davenport to Leigh Creek 132 kV line and establish associated substation assets (including reactive support).
Estimated cost:	$60 million
Project category:	Augmentation
Timing:	Uncertain
Project status:	Contingent – refer to Table 4 for trigger

Project need and option analysis:

The existing Davenport to Leigh Creek 132 kV transmission line was designed with a thermal rating of 49 °C (120 °F), which has been shown to be inadequate for Australian summer conditions. Most circuits designed and built to this standard have been uprated or replaced. However, the Davenport to Leigh Creek 132 kV line continues to have an adequate rating for the small load it currently supplies at Neuroodla, the Leigh Creek coal mine and Leigh Creek Township, so uprating or replacement has not yet been necessary.

Aerial laser survey data has revealed that, assuming the structures are mechanically capable, the connection of a 35 MW load at Leigh Creek would require some 300 of the total 600 spans in the existing 240 km line to be uprated to meet minimum ground clearance requirements.

Any step load increase causing the line to exceed its thermal limit of 10 MVA would require the line to be significantly uprated or rebuilt.

Both the timing and scope of this project are uncertain at this point in time.

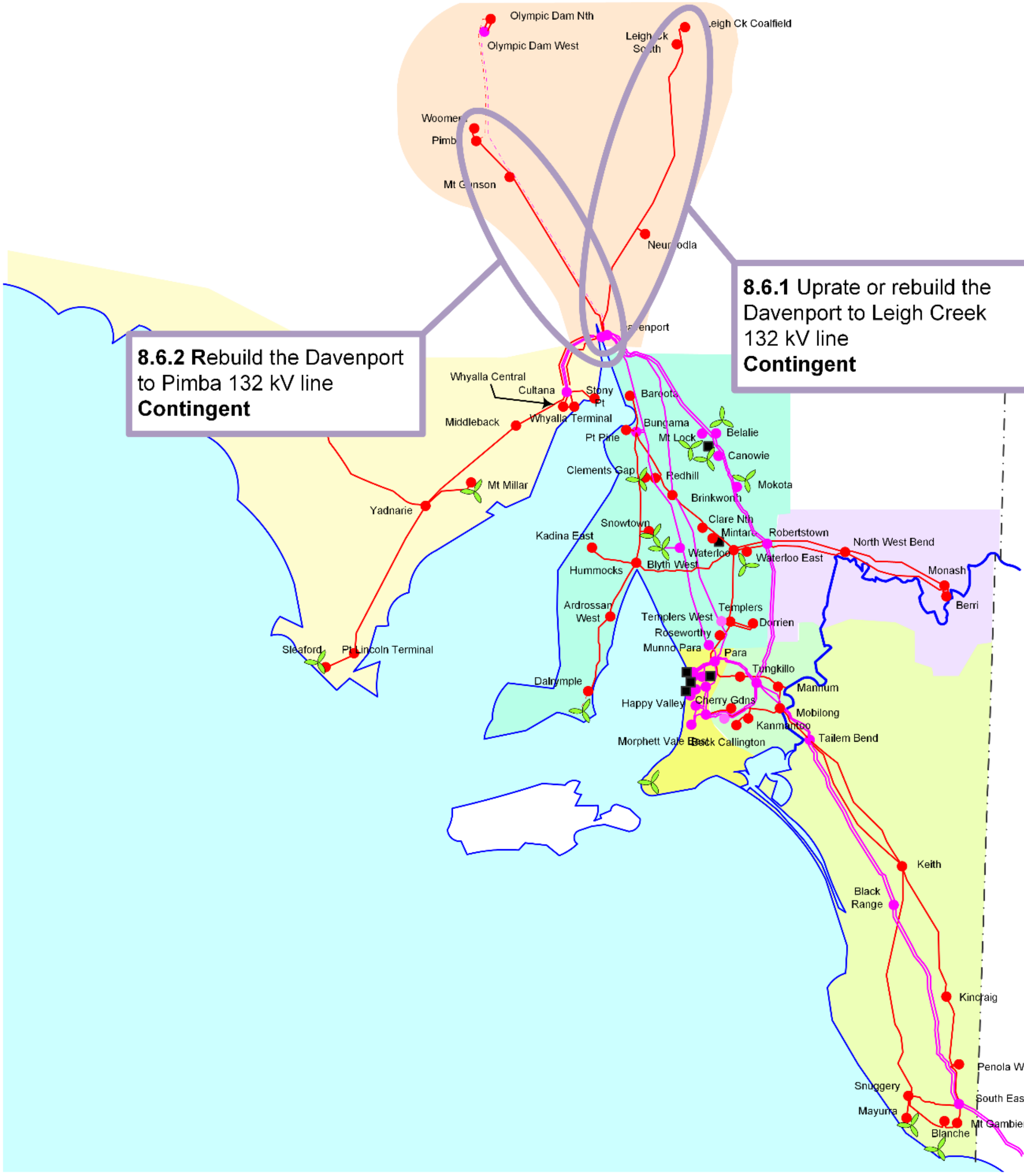

Figure 8-5: Projects that may be required if potential spot loads connect

8.6.2 Upper North region western 132 kV line reinforcement

Scope of work:	Rebuild the Davenport to Pimba 132 kV line and establish associated substation assets (including reactive support).
Estimated cost:	$110 million
Project category:	Augmentation
Timing:	Uncertain
Project status:	Contingent – refer to Table 4 for trigger

Project need and option analysis:

The existing Davenport to Pimba 132 kV transmission line was designed with a thermal rating of 49 °C (120 °F), which has been shown to be inadequate for Australian summer conditions. The line has a rating of 76 MVA, as it was uprated to allow this level of loading during the 1980s to support the initial development of Olympic Dam. That uprate work involved lifting the lowest spans using insulated cross-arms. This uprating represents the mechanical limit for the structures involved.

Any step load increase causing the line to exceed its thermal limit of 76 MVA would require the line to be rebuilt.

Both the timing and scope of this project are uncertain at this point in time.

8.7 Minimum demand

For many years, minimum demands on South Australia's electricity transmission network typically occurred at roughly 4 AM in the morning during periods of mild weather, such as during April and Spring. More recently, the increasing penetration of rooftop solar PV has seen periods in the middle of the day record even lower demand levels, typically on mild, sunny weekends or public holidays. AEMO forecasts the level of minimum demand in South Australia to continue to decrease over the forecast period (section 5.2.1).

Low demands drawn from the transmission level can correlate closely with a decreased dispatch of large synchronous generators, the impacts of which are considered in section 8.3.

Our analysis has shown that high main grid voltage levels are expected to occur at such times of extremely low demand. Investment is needed to prevent voltage levels from exceeding equipment ratings during system normal conditions or after an unplanned outage of any single line, transformer, or other network element.

As a result, we have determined that four projects will be needed over the 10-year planning period to manage the impact of declining minimum demand (Figure 8-6, details in sections 8.7.1 to 8.7.4).

8.7.1 Install a 50 Mvar 275 kV switched reactor at Templers West

Scope of work:	Install a switched 50 Mvar 275 kV reactor at Templers West
Estimated cost:	<$5 million
Project category:	Security/Compliance
Timing:	November 2018
Project status:	RIT-T to be commenced in second half of 2017

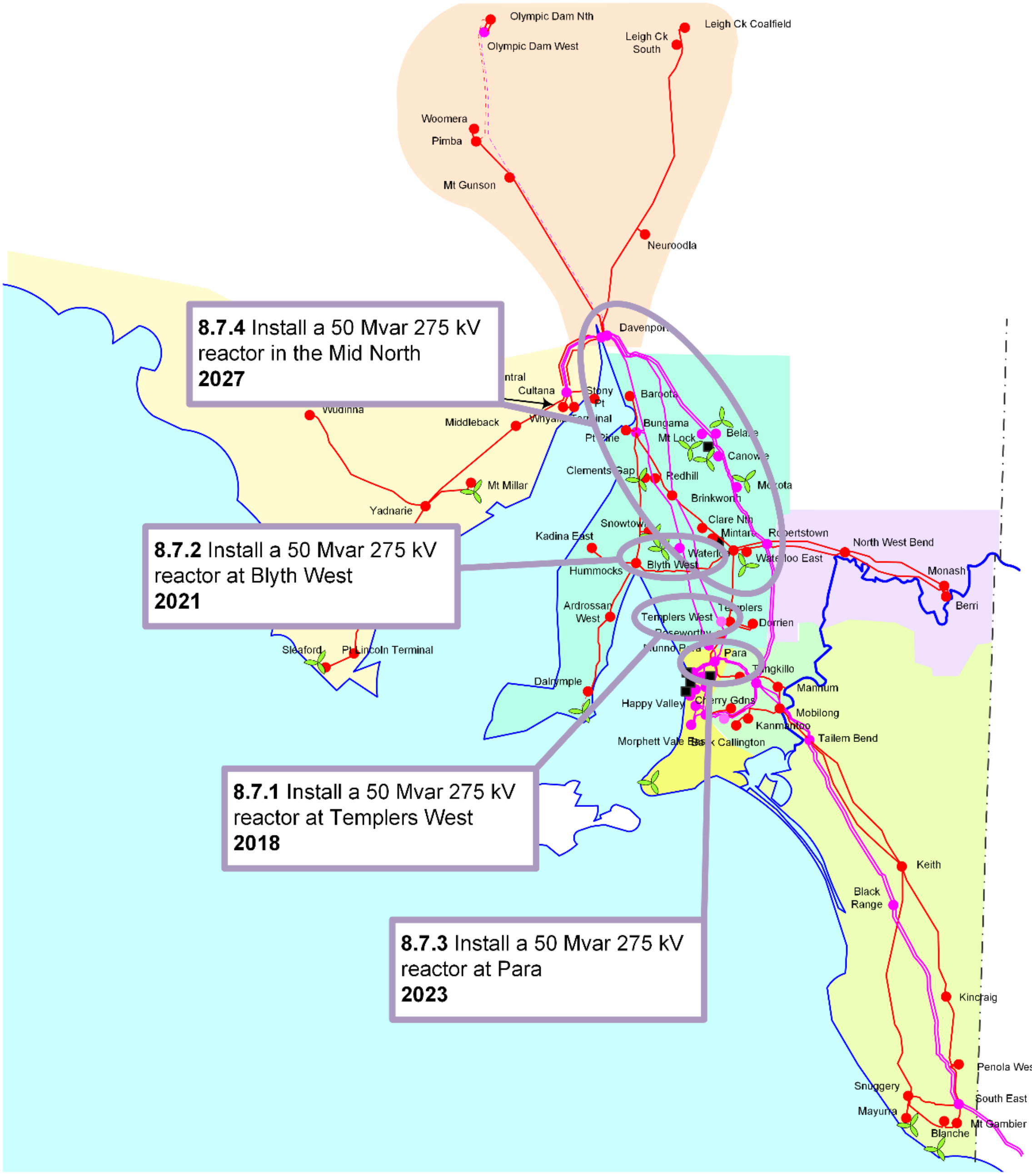

Figure 8-6: Projects that are proposed to manage the impact of declining minimum demand

Project need and option analysis:

Studies have shown that steady-state voltage levels on the South Australian transmission system may breach 110% at times of low demand from 2018-19, following a single contingency event of an in-service generator or significant item of reactive control plant. This can be addressed by installing an additional 50 Mvar 275 kV reactor in 2018 to limit high voltage levels on the transmission network at times of low system demand.

Studies indicate that installing this reactor at Templers West will optimise the benefit.

As this planned reactor in combination with the other reactors planned at Blyth West and Para (sections 8.7.2 and 0) target a similar identified need and the total cost exceeds $6 million, the RIT-T will be applied to the proposed series of investments to the RIT-T. A more detailed options analysis, including consideration of network support options, is planned to be done as part of the RIT-T for this project.

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

8.7.2 Install a 50 Mvar 275 kV switched reactor at Blyth West

Scope of work:	Install a switched 50 Mvar 275 kV reactor at Blyth West
Estimated cost:	<$5 million
Project category:	Security/Compliance
Timing:	August 2021
Project status:	Proposed

Project need and option analysis:

Studies have shown that steady-state voltage levels on the South Australian transmission system may breach 110% at times of low demand from 2021–22, following a single contingency event of an in-service generator or significant item of reactive control plant. This can be addressed by installing an additional 50 Mvar 275 kV reactor in 2021 to limit high voltage levels on the transmission network at times of low system demand.

Studies indicate that installing this reactor at Blyth West, along with the reactor proposed for Templers West in 2018 (section 8.7.1) will optimise the benefit. A more detailed options analysis, including consideration of network support options, is planned to be done as part of the RIT-T for the Templers West reactor project.

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

8.7.3 Install a second 50 Mvar 275 kV switched reactor at Para

Scope of work:	Install a second switched 50 Mvar 275 kV reactor at Para
Estimated cost:	<$5 million
Project category:	Security/Compliance
Timing:	August 2023
Project status:	Proposed

Project need and option analysis:

Studies have shown that steady-state voltage levels on the South Australian transmission system may again breach 110% at times of low demand from 2023–24,

following a single contingency event of an in-service generator or significant item of reactive control plant. This can be addressed by installing an additional 50 Mvar 275 kV reactor in 2023 to limit high voltage levels on the transmission network at times of low system demand.

Studies indicate that installing this reactor at Para, along with the reactors proposed for Templers West in 2018 (section 8.7.1) and Blyth West in 2021 (section 8.7.2) will optimise the benefit. A more detailed options analysis, including consideration of network support options, is planned to be done as part of the RIT-T for the Templers West reactor project.

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

8.7.4 Install an additional 50 Mvar 275 kV switched reactor in the Mid North

Scope of work:	Install an additional switched 50 Mvar 275 kV reactor in the Mid North
Estimated cost:	<$5 million
Project category:	Security/Compliance
Timing:	Before August 2027
Project status:	Proposed

Project need and option analysis:

AEMO's 2016 NEFR forecast that minimum demand supplied by SA's transmission network may drop to below zero from summer 2027-28 (that is, continued rooftop solar PV installations would reach a level that will more than offset consumer demand). ElectraNet's studies show that steady-state voltage levels on the South Australian transmission system may again breach 110% at such times of low demand, following a single contingency event of an in-service generator or significant item of reactive control plant. This can be addressed by installing an additional 50 Mvar 275 kV reactor before August 2027, to limit high voltage levels on the transmission network at times of low system demand.

Studies indicate that installing this reactor at a suitable location in the Mid North, along with the reactors proposed for Templers West in 2018 (section 8.7.1), Blyth West in 2021 (section 8.7.2), and Para (section 0) will optimise the benefit.

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

8.8 Maximum fault levels

For safety reasons, transmission system maximum 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.

Based on the 2016 NTNDP least cost generation expansion plan, there will be minimal new conventional generation built in South Australia within the next ten years. Substation fault levels were assessed (Appendix E) to ensure they will remain within design and equipment limits.

8.9 Emergency Control Schemes

Effective 6 April 2017, the AEMC implemented a new rule to establish a framework for the consideration and management of power system frequency risks arising from non-credible contingency events.[45]

The framework has three main parts.

1. Power System Frequency Review

   AEMO is obliged to collaborate with TNSPs to undertake an integrated, periodic review of power system frequency risks associated with non-credible contingency events at least every two years, with the first review expected to be completed by April 2018.

2. New and improved emergency frequency control schemes

   Where the Power System Frequency Review identifies the need for new or modified emergency control schemes, the RIT-T or RIT-D is to be used to assess the economic case for the change, in accordance with the existing framework for planning.

3. The declaration and management of a Protected Event

   Where the Power System Frequency Review identifies one or more non-credible contingency events which AEMO considers it may be economically efficient to manage using operational measures in addition to some limited load or generation shedding, AEMO will submit a request to the Reliability Panel to have the event declared a “protected event”. The Reliability Panel will then perform an economic assessment, and declare the event a protected event if the benefits of managing the event outweigh the costs.

   After a protected event has been declared, AEMO will operate the power system so that the power system security standards will be maintained if the protected event were to occur.

   If the Reliability Panel’s assessment shows that a new or modified emergency frequency control scheme is an efficient investment to manage the protected event, the Panel will define the target capabilities of the scheme. NSPs would be required to design, implement and monitor the scheme in accordance with the standard, and would be exempt from applying the RIT-T or RIT-D.

AEMO is yet to undertake the first power system frequency review. However, ElectraNet and AEMO have previously collaborated to develop an Over Frequency Generation Shedding Scheme (section 8.9.1), and have commenced collaboration to design a special protection scheme to protect the South Australian electricity system against the risks of certain non-credible events (section 8.9.2).

[45] Details available at aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen.

8.9.1 Implement a coordinated Over Frequency Generation Shedding scheme

Scope of work: Implement an Over-frequency Generation Shedding (OFGS) scheme for South Australian wind farms, including a backup scheme on the network side of the wind farm connections

Estimated cost: <$5 million

Project category: Security/Compliance

Timing: 2017

Project status: Committed

Project need and option analysis:

AEMO has identified that uncontrolled generator trips could happen if an unplanned outage of the Heywood interconnector occurred at a time when generation from South Australian wind farms exceeded South Australian demand. To address this risk, AEMO and ElectraNet are working together to implement a coordinated OFGS scheme, to trip excess generation in a controlled order to restore the balance between supply and demand and allow the South Australian frequency to recover to within the frequency operating standards.

The OFGS scheme will operate by tripping South Australian wind farms in a pre-determined sequence starting at 51.0 Hz, with those that make the smallest contribution to system inertia tripped earliest in the sequence.

8.9.2 Protect against system islanding for the non-credible loss of multiple generators

Scope of work: Implement a Special Protection Scheme to maintain system security and prevent the islanding of the South Australian power system during non-credible events

Estimated cost: $4-8 million

Project category: Security/Compliance

Timing: Stage 1: 31 December 2017, Stage 2: 2019-20

Project status: Planned

Project need and option analysis:

As part of AEMO's final report into the South Australian black system event on 28 September 2016[46], AEMO found that because of the difficulties in forming a stable island in South Australia, it would be preferable to avoid islanding if at all possible.

As a result, the AEMO report included a recommendation (Recommendation 8) for AEMO to work with ElectraNet to investigate the feasibility of developing a Special Protection Scheme (SPS). The SPS will be designed to operate in response to sudden excessive flows on the Heywood interconnector, to initiate load shedding quickly enough to prevent separation.

[46] March 2017 AEMO report – Black System South Australia 28 September 2016, available from aemo.com.au

ElectraNet and AEMO are currently consulting together on the design of such an SPS. The SPS is proposed to be developed in a staged approach:

Stage 1: Develop an interim special protection scheme to mitigate risks to the South Australian system by implementing very rapid load shedding to:

- help quickly restore the balance between supply and demand following the loss of multiple generators in South Australia
- reduce the risk separation of South Australia from the rest of the NEM.

This interim scheme is proposed to be implemented in a short time frame and the approach will simply trip pre-identified loads, largely using existing detection devices to deliver a practical scheme in the short time frame.

Stage 2: Develop a more sophisticated and adaptive scheme with dedicated processors that use real time load-generation balancing algorithms, real time measurement of loads, battery status and HVDC interconnector flows. The approach will be to use predictive methods to more accurately identify the amount of load that needs to be tripped, after taking into account the available response from devices that can provide rapid power injection and load relief. The SPS will initiate action after the loss of multiple generators within South Australia, to restore the balance between supply and demand and thereby prevent sudden excessive flows on the Heywood interconnector and the loss of synchronism of the South Australian system, enabling South Australia to remain connected to the rest of the NEM.

ElectraNet

South Australian Transmission Annual Planning Report

Appendices

June 2017

Appendix A Transmission Planning Framework

A1 South Australian electricity market framework

A1.1 Australian Energy Market Operator (AEMO)

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

- performance assessments of connection points 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
- the historical and forecast future demand for electricity based on both seasonal peak usage and aggregate energy usage.

AEMO provides the above information in a collection of advisory reports for South Australia, which are released during each year (available on AEMO's South Australian Advisory Functions[47] webpage), and in the NTNDP which is published annually in December.

A1.2 Essential Services Commission of South Australia (ESCOSA)

The Essential Services Commission Act 2002, together with the Electricity Act 1996 and regulations, establishes the Essential Services Commission of South Australia with regulatory powers in relation to regulated industries.

Those powers include the ability to make codes, rules and guidelines, and to undertake performance monitoring. This legislation is intended to support competitive markets in the electricity supply industry, and provide regulatory oversight of the monopoly transmission and distribution network sectors of the industry.

Major features of the regulatory regime include the establishment of:

- the Essential Services Commission, with specified regulatory powers in relation to the electricity supply industry, and with significant independence from Government.
- the Energy & Water Ombudsman SA scheme (EWOSA Scheme) which provides customers of licensed transmission, distribution and retail businesses with access to free and alternative dispute resolution mechanisms.

[47] Available at aemo.com.au.

- the establishment of the Technical Regulator, under Part 2 of the Electricity Act 1996, which has responsibility for specified technical and safety matters in relation to the electricity supply industry.

The principal functions and powers of the Essential Services Commission in relation to the electricity supply industry include:

- administering the licensing regime for electricity entities (generation, transmission, distribution, system control and off-grid suppliers), including the issuing and ongoing monitoring of those licences
- monitoring and reporting on the performance of licensed entities with regulatory obligations imposed under Acts of Parliament, the licences they hold, industry codes, rules and guidelines issued by the Essential Services Commission
- making industry codes regulating the behaviour of licensed entities
- enforcing compliance with licensees' regulatory obligations, including undertaking enforcement action as appropriate.

A1.3 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. This includes the requirement 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 www.aemc.gov.au.

At time of publication, the current version of the Rules is Version 92.

A2 ElectraNet's responsibilities under the Rules

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 earlier in Appendix A.

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

- ensure that the network is planned, designed, constructed, operated and maintained with the safety of the public and workers as the paramount consideration
- ensure that the network is operated with sufficient capability to provide the minimum level of transmission network services required by customers
- ensure that the network complies with technical and reliability standards contained in the Rules and jurisdictional instruments such as the ETC
- ensure 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
- conduct joint planning with 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
- provide information to registered participants and interested parties on projected network limitations and the required timeframes for action
- develop 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.

A2.1 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

- 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 2017 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 A, which demonstrates ElectraNet's assessment of compliance with the requirements of the Rules.

A2.2 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 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.[48] 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 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 $6 million
- replacement and maintenance projects where the estimated capital cost of the augmentation component (if there is one) is less than $6 million
- network reconfigurations that have an estimated capital cost of less than $6 million, or otherwise, are likely to have no material impact on network users
- connection assets
- negotiated transmission service investments
- protected event Emergency Frequency Control Scheme investment that is also not intended to augment the transmission network.

The RIT-T 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.[49]

[48] Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-investment-test-for-transmission-rit-t-and-application-guidelines-2010.

[49] 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).

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. Details of proposed non-network solutions can be submitted to consultation@electranet.com.au. All RIT-T reports published by ElectraNet and non confidential submissions received during the consultation process are available from electranet.com.au.

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

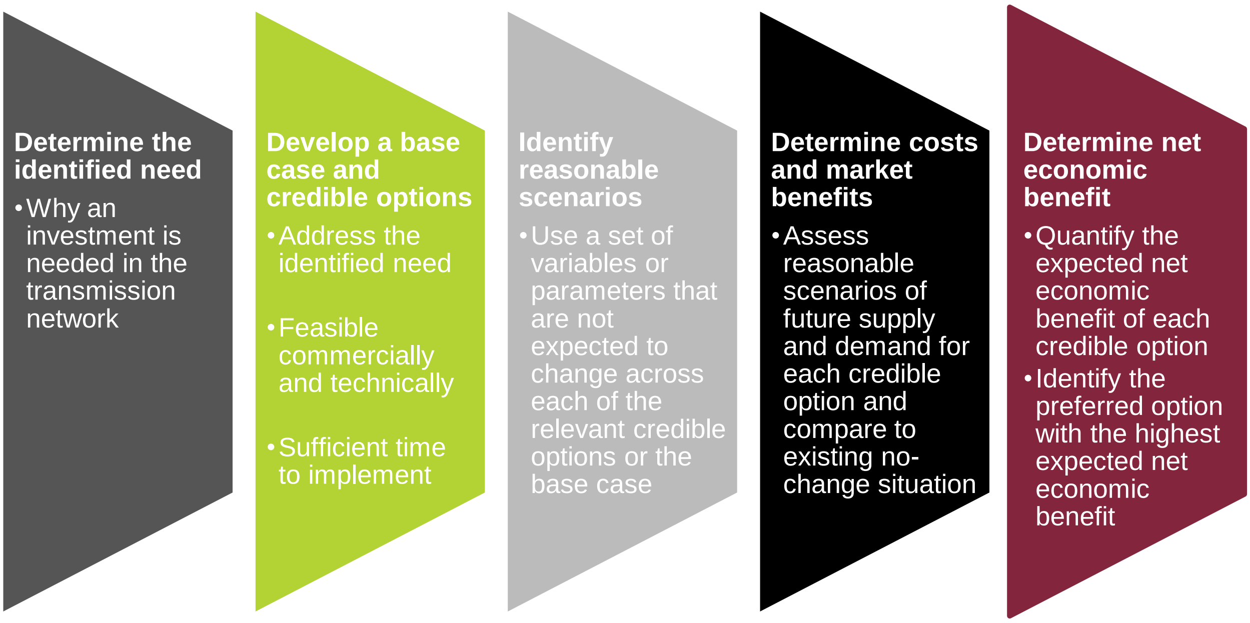

Figure A-1: ElectraNet's approach to the Regulatory Investment Test for Transmission (RIT-T) process

A3 ElectraNet's responsibilities under the Electricity Transmission Code (ETC)

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.

ESCOSA most recently amended the reliability standards contained in the ETC to be effective from 1 July 2018 (Table A-1).[50]

[50] The full version of the ETC version TC/09 is available at escosa.sa.gov.au.

Table A-1: Summary of ETC redundancy requirements

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 maximum demand (AMD)				
'N-1' capacity	Nil		100% of AMD		
'N-1' continuous capability	Nil			100% of AMD 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 176 MW
Restoration time to 'N-1' standard after outage	N/A		As soon as practicable - best endeavours		
Transformer capacity					
'N' capacity	100% of AMD				
'N-1' capacity	Nil	100% of AMD			
'N-1' continuous capability	None stated	100% of AMD for loss of single transformer or network support arrangement	Nil	100% of AMD 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 176 MW
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 AMD 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.

Appendix B Compliance checklist

This section sets out a compliance checklist which demonstrates the compliance of ElectraNet's 2017 Transmission Annual Planning Report with the requirements of clause 5.12.2(c) of version 92 of the Rules.

Table B-1: Compliance Checklist

Summary of requirements	Section
The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[51] and 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), including at least: (i) a description of the forecasting methodology, sources of input information, and the assumptions applied in respect of the forecast loads; (ii) a description of high, most likely and low growth scenarios in respect of the forecast loads; (iii) an analysis and explanation of any aspects of forecast loads provided in the Transmission Annual Planning Report that have changed significantly from forecasts provided in the Transmission Annual Planning Report from the previous year; and (iv) an analysis and explanation of any aspects of forecast loads provided in the Transmission Annual Planning Report from the previous year which are significantly different from the actual outcome;	Chapter 5, and the *2017 South Australian Connection Point Forecasts Report*[52]
(2) planning proposals for future connection points;	Section 6.4
(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, including at least: (i) a description of the constraints and their causes; (ii) the timing and likelihood of the constraints; (iii) a brief discussion of the types of planned future projects that may address the constraints over the next 5 years, if such projects are required; and (iv) sufficient information to enable an understanding of the constraints and how such forecasts were developed;	Chapter 8
(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;	N/A

51 The first TAPR Guideline is yet to be developed by the AER.
52 Available at electranet.com.au

Summary of requirements	Section
(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;	Sections 8.3 to 8.8
(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;	Section 4.1
(6A) for proposed new or modified emergency frequency control schemes, the manner in which the project relates to the most recent power system frequency risk review;	Section 8.9
(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;	Table G-3
(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;	N/A
(9) emergency controls in place under clause S5.1.8, including the Network Service Provider’s assessment of the need for new or altered emergency controls under that clause;	Sections 3.5.5 and 8.9
(10) facilities in place under clause S5.1.10; and	Section 3.5.5

Summary of requirements	Section
(11) an analysis and explanation of any other aspects of the Transmission Annual Planning Report that have changed significantly from the preceding year's Transmission Annual Planning Report, including the reasons why the changes have occurred; and	Executive Summary
(12) the results of joint planning (if any) undertaken with a Transmission Network Service Provider under clause 5.14.3 in the preceding year, including a summary of the process and methodology used by the Transmission Network Service Providers to undertake joint planning and the outcomes of that joint planning.	Sections 3.5.1, 3.5.3, 3.5.5, 8.4, and 8.9

Appendix C Regional networks

ElectraNet's Main Grid (Figure 2-2) is connected to seven regional networks and two interconnectors of varying transfer capability (Appendix D) that connect South Australia to the Victorian region of the NEM.

C1 Metropolitan region

The 275 kV transmission Metropolitan region includes connection points that service the Adelaide central business district (CBD) and metropolitan residential, commercial and industrial loads (Figure C-1). Over 80% of the South Australian population is contained within and serviced by the metropolitan transmission region. 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.

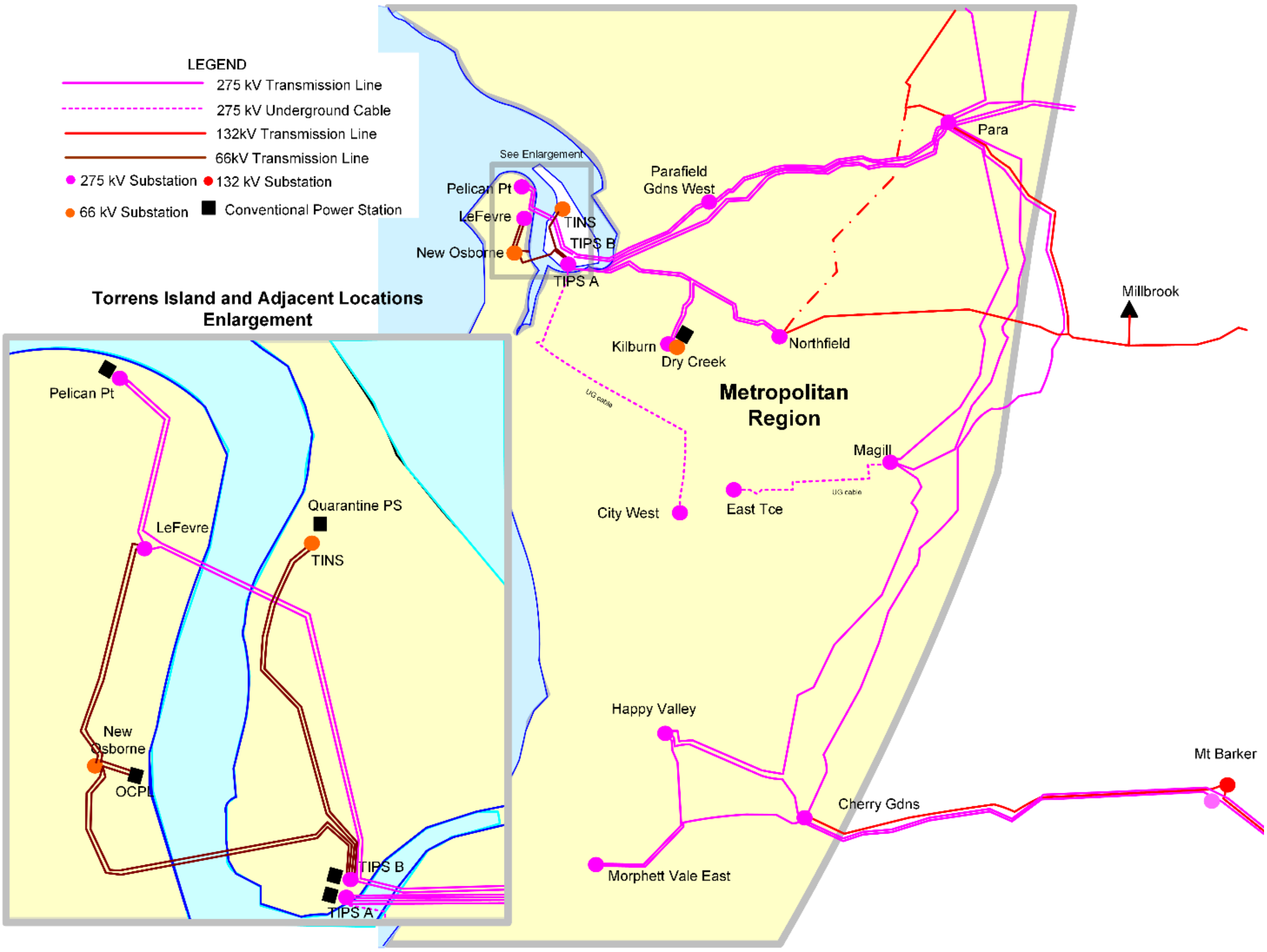

Figure C-1: Metropolitan transmission network and supply region

C2 Eastern Hills region

The Eastern Hills 132 kV transmission system (Figure C-2) supplies six major load centres and electricity to five SA Power Networks connection point substations as well as seven SA Water pumping stations. The Eastern Hills derives its supply from the Main Grid 275 kV network via three 275/132 kV substations. The Eastern Hills 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 Heywood interconnection. As a consequence, power flows in the Eastern Hills are determined by flows on the Heywood interconnector as well as loads supplied within the region.

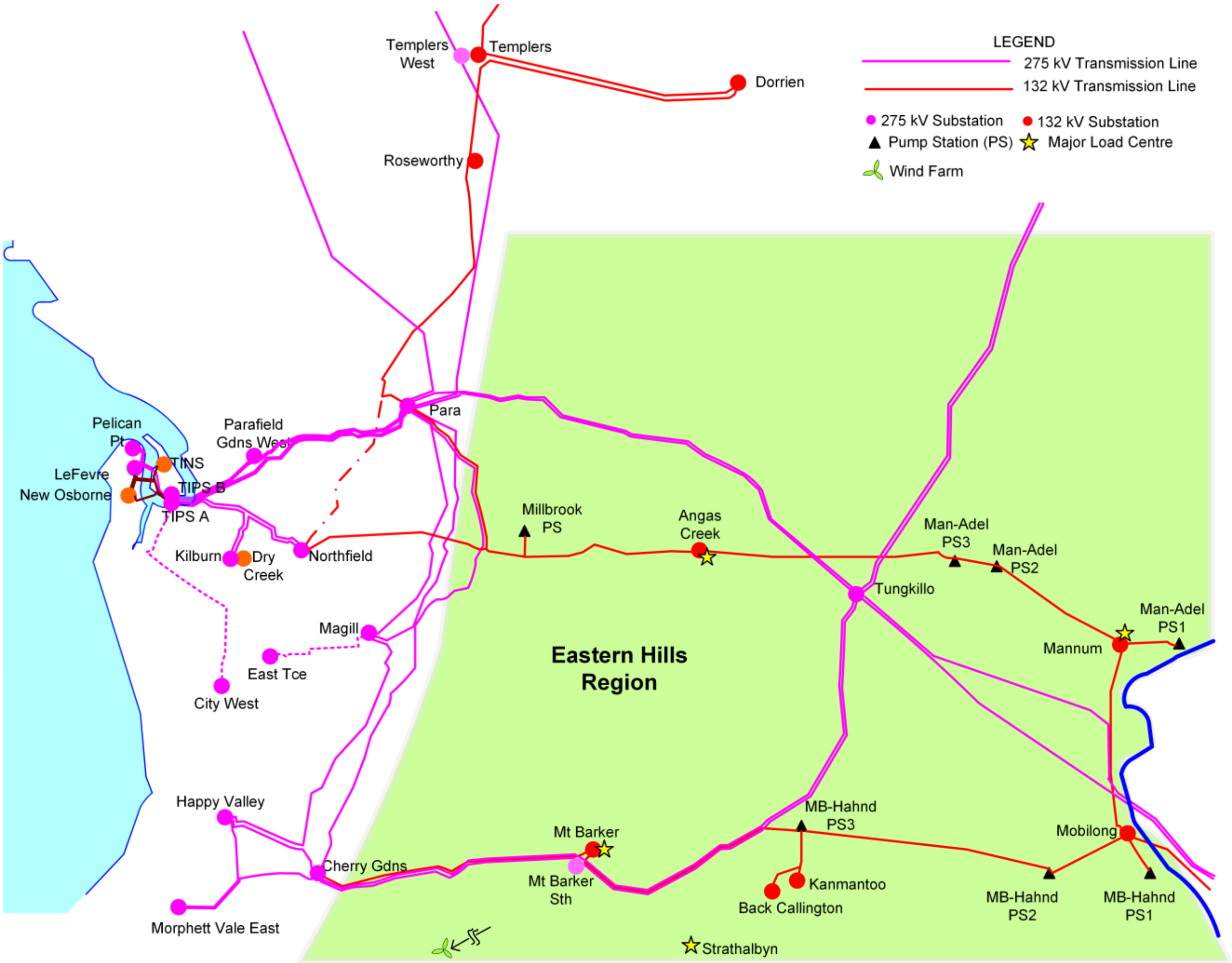

Figure C-2: Eastern Hills transmission network and supply region

C3 Mid North region

The Mid North 132 kV sub-transmission system network (Figure C-3) supplies five major load centres as well as the Barossa Valley and Yorke Peninsula regions. It is supplied from the Main Grid 275 kV system via five 275/132 kV substations. It is also connected to the 132 kV Eastern Hills sub-transmission system at Para, and the 132 kV Riverland sub-transmission system at Robertstown. The Mid North system has been developed progressively since 1952 and now operates in parallel with the Main Grid system that connects the major sources of generation in the Mid North region 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 flows on the Main Grid between Davenport and the Metropolitan region.

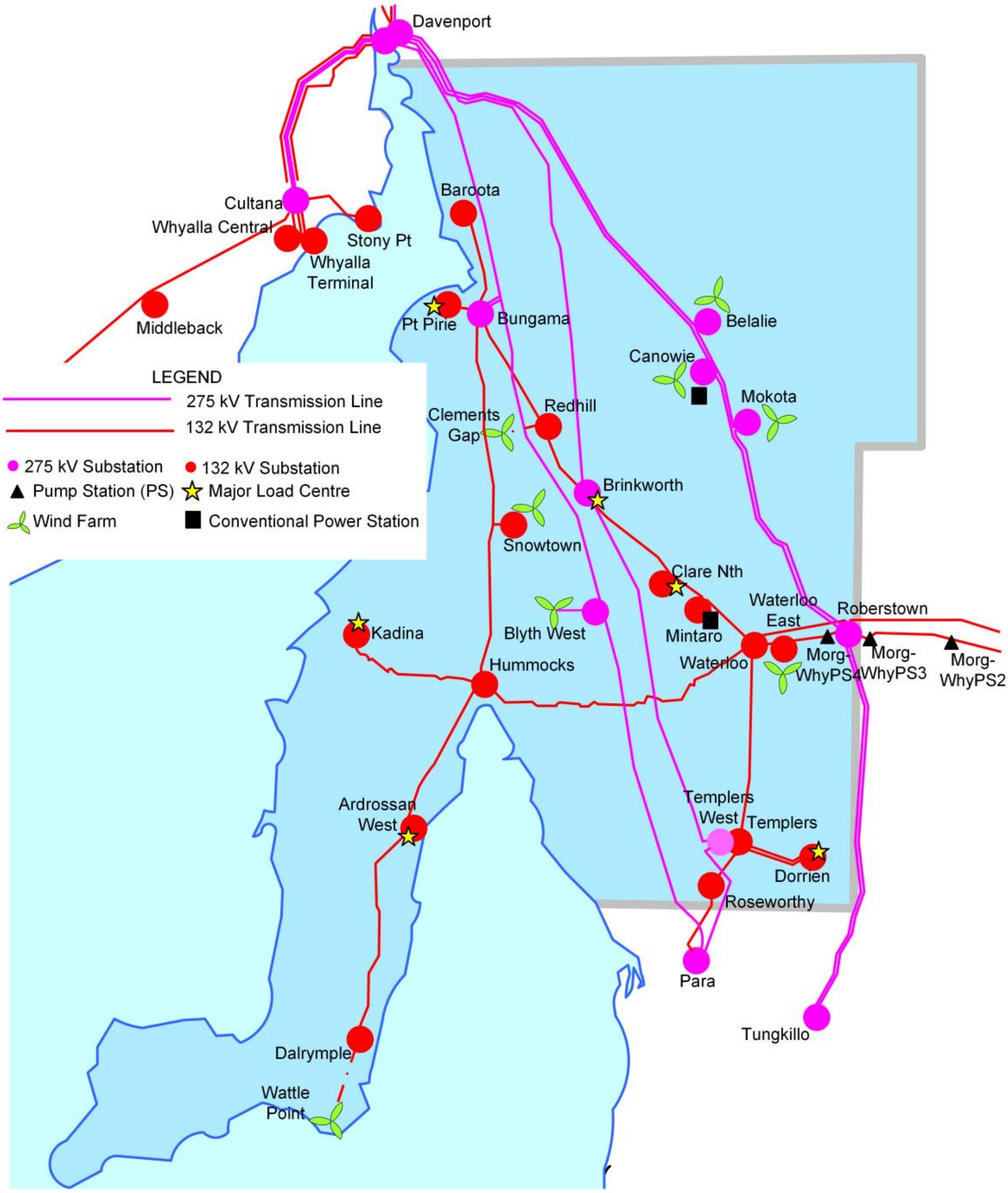

Figure C-3: Mid North transmission network and supply region

C4 Riverland region

The Riverland 132 kV transmission system (Figure C-4) comprises a network that supplies six major load centres, numerous SA Water pumping stations and SA Power Networks' connection point substations. It derives its electricity supply from the Main Grid through two 275/132 kV transformers located at the Robertstown substation and from the Murraylink interconnector. The Riverland system has been progressively developed since 1953 and comprises two 132 kV circuits that essentially connect the Robertstown and Berri substations via a number of intermediate connection points. The system is a connection point 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.

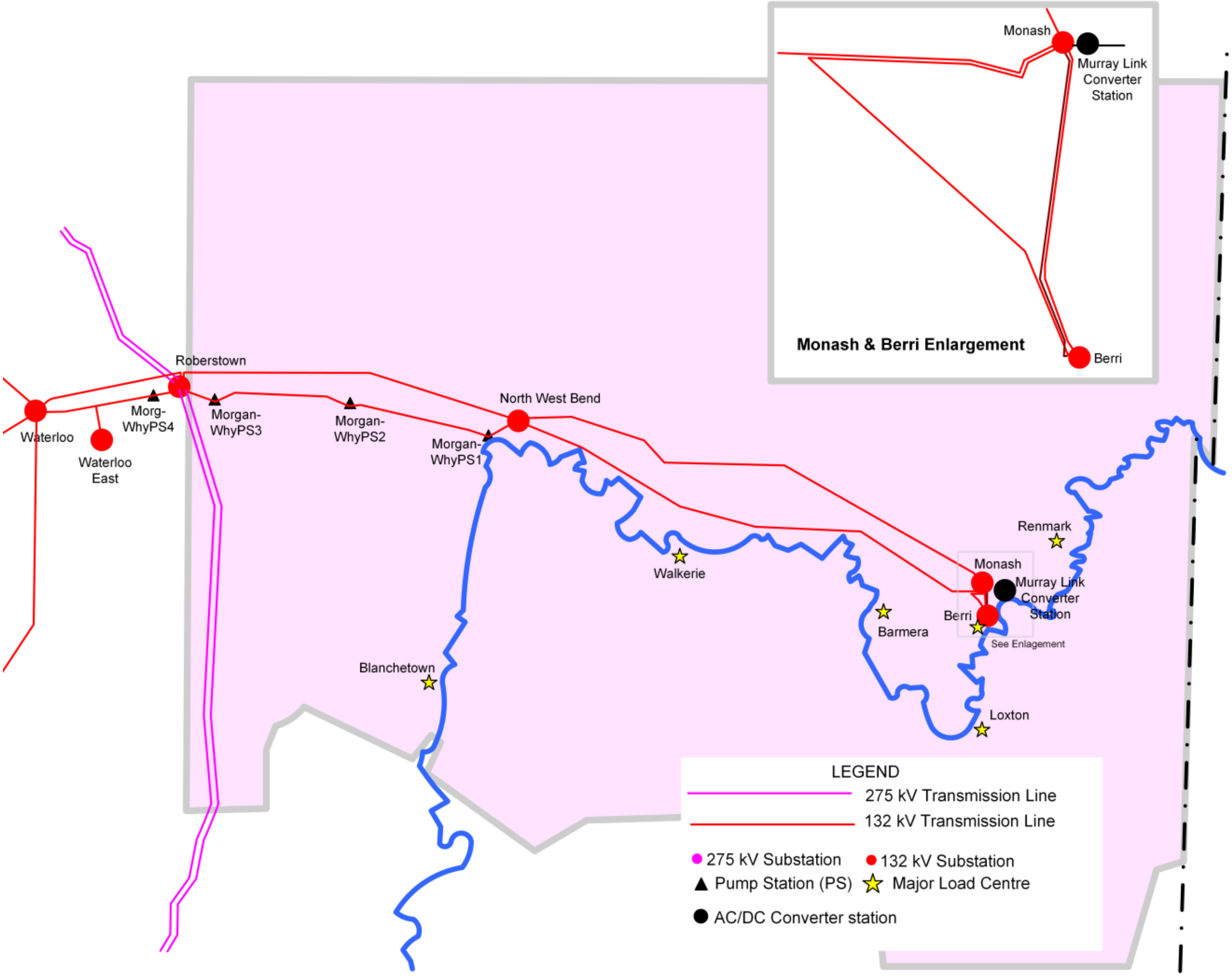

Figure C-4: Riverland transmission network and supply region

C5 South East region

The South East region (Figure C-5) contains a mixture of electrical loads including agricultural; light and heavy industrial; rural; urban; and commercial. The South East 132 kV transmission system supplies ten major load centres and it derives its supply from the Main Grid via 275/132 kV substations located at Tailem Bend and South East. The network was extended to Tailem Bend in 1976 and a 275/132 kV substation was established there to feed into South East. Gas turbine generating plant was installed at Snuggery in 1980 and a 132/33 kV substation constructed at Blanche in 1981. The South East network was further augmented 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 also connected to the Victorian transmission system at Heywood 500/275 kV substation.

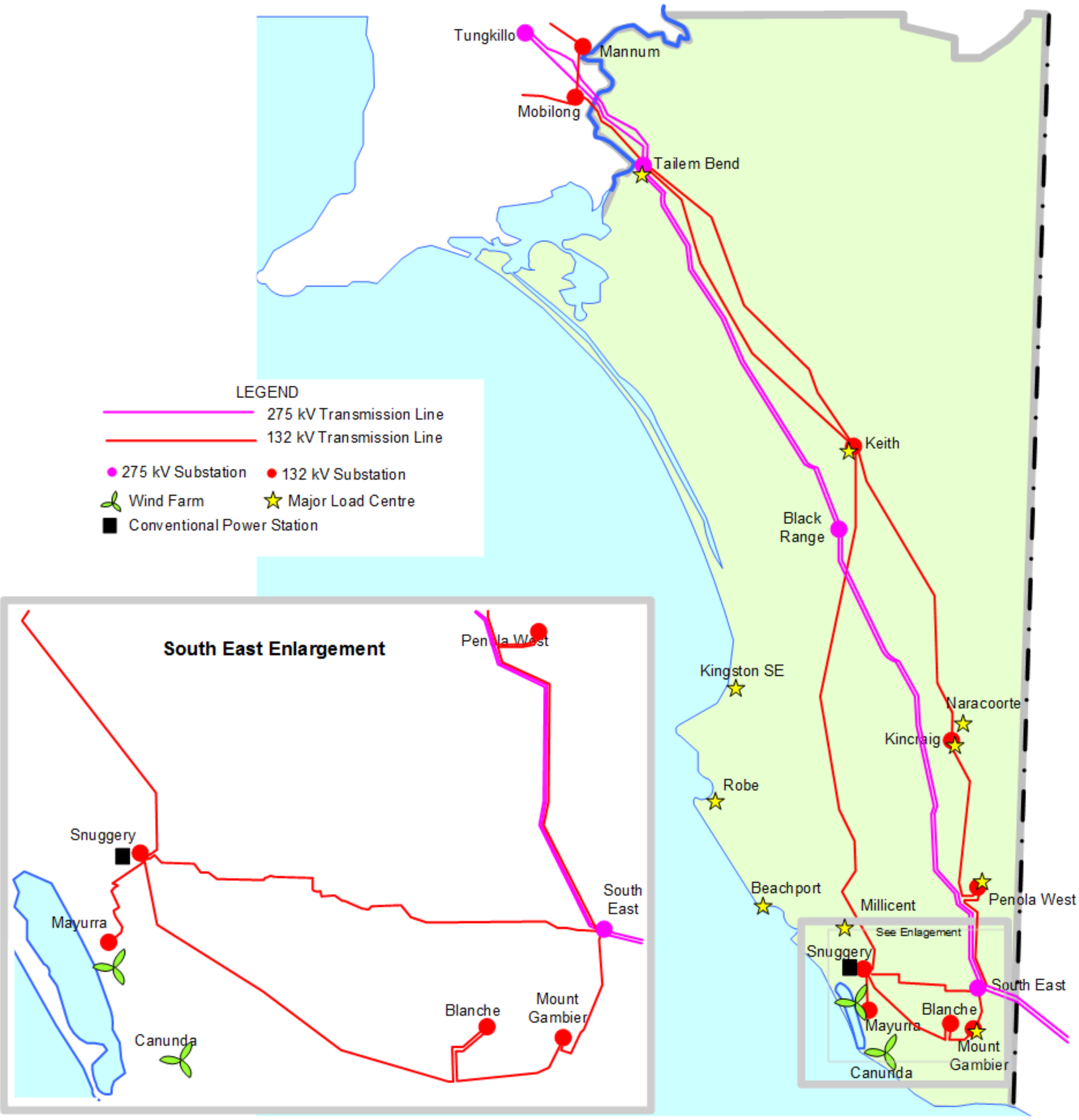

Figure C-5: South East transmission network and supply region

C6 Eyre Peninsula region

The Eyre Peninsula (Figure C-6) 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 via the 275/132 kV Cultana substation. The major industrial centre of Whyalla is supplied from Cultana by 132 kV lines, which are operated in parallel. 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.

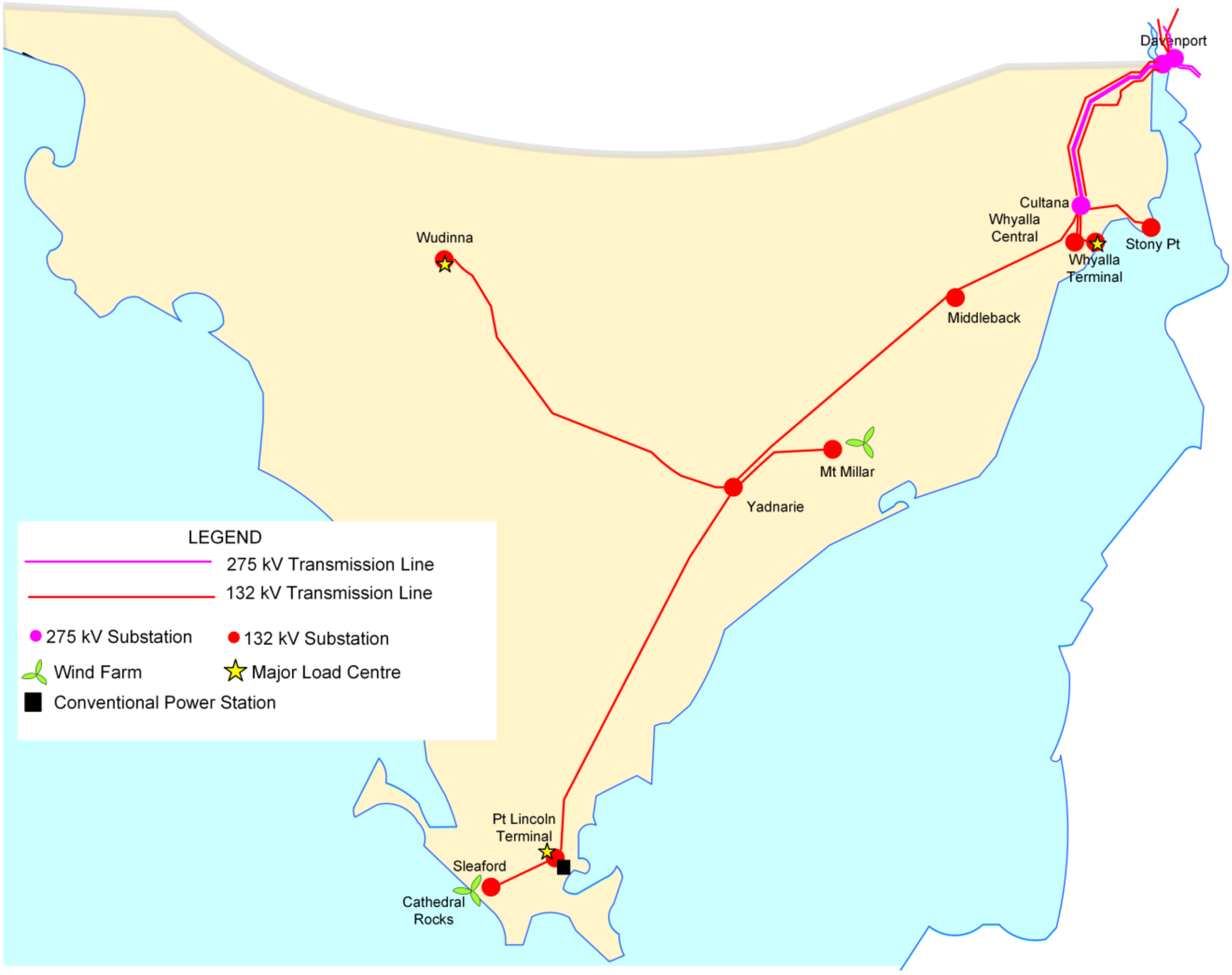

Figure C-6: Eyre Peninsula transmission network and supply region

C7 Upper North region

The Upper North 132kV sub-transmission network (Figure C-7) supplies major mining loads and a mix of agricultural, industrial, rural, urban and commercial loads. Its supply comes from the Main Grid via a 275/132 kV Davenport substation (near Port Augusta), which also supplies the region's major commercial centre. The Upper North 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. A 275 kV connection point was provided at Davenport in 1998 to facilitate expansion of mining operations at Olympic Dam and there are now two privately owned lines in the region: the Olympic Dam to Pimba 132 kV line and the Davenport to Olympic Dam 275 kV line.

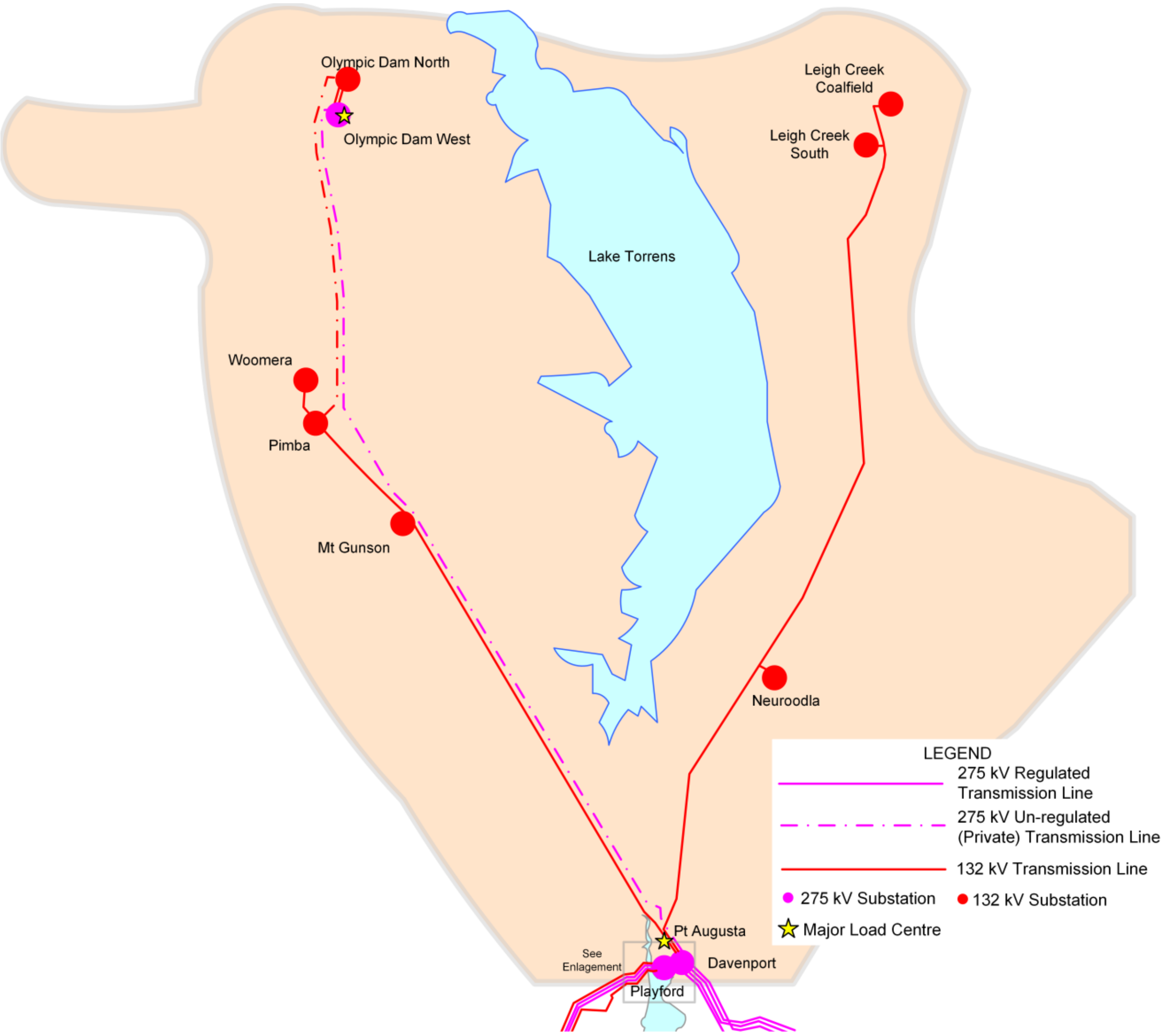

Figure C-7: Upper North transmission network and supply region

Appendix D Inter-regional transfer capacity

The combined maximum transfer capability for import into South Australia from Victoria under system normal operating conditions is currently 820 MW across the Heywood (section D1) and Murraylink (section D2) interconnectors.

The interconnector transfer capability will change once the full upgraded capacity of the Heywood interconnector has been released, which will occur after the completion of interconnected network tests. The combined maximum transfer capability between South Australia and Victoria under system normal operating conditions will then increase to 870 MW across the Heywood and Murraylink interconnectors.

D1 Heywood interconnector

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

Heywood interconnector transfer capacity is principally limited by thermal and voltage stability related constraints. There are also small signal oscillatory constraints on the South Australian network.

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

D1.1 Import and export capability

The import capability of the interconnector is defined by three 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.

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 Victoria.

   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. Limit equations are based on system load indices of Np = 1.4 and Nq = 3.0.

   The SA system normal equations are included in Section D1.2 of this Transmission Annual Planning Report.

3. Oscillatory Stability Transfer Capability

The oscillatory stability import and export limit in South Australia under various system operating 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 import and export capability up to 870 MW and 810 MW. 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.

D1.2 Heywood interconnector transfer limit equations

The import and export capability of the Heywood interconnector due to long term voltage stability under system normal operating conditions has been updated to take account of all recently completed projects in South Australia, as well as the Heywood interconnector upgrade project. These updated South Australian system normal import and export equations, which will apply after the full capacity of the upgraded Heywood interconnector has been released, are shown below.

Long term voltage stability transfer capability based on SA largest generation loss contingency

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	=	2.03
Lad	=	Ladbroke Grove Power Station output in MW
C2	=	-0.52
LB1	=	Lake Bonney Wind Farm Stage 1 output in MW
C3	=	-0.65
Can	=	Canunda Wind Farm output in MW
C4	=	-0.74
LB2	=	Lake Bonney Wind Farm Stage 2 output in MW
C5	=	-0.79
LB3	=	Lake Bonney Wind Farm Stage 3 output in MW
C6	=	-0.79
Snug	=	Snuggery Power Station output in MW
C7	=	-1.24
SALGEN	=	South Australia’s largest single in-service generator in MW (largest potential generation loss under a single credible contingency)
C8	=	-1.25
Const	=	917

Short term voltage stability transfer capability based on SA largest generation loss contingency

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	=	2.13
Lad	=	Ladbroke Grove Power Station output in MW
C2	=	-0.17
LB1	=	Lake Bonney Wind Farm Stage 1 output in MW
C3	=	-0.38
Can	=	Canunda Wind Farm output in MW
C4	=	-1.30
LB2	=	Lake Bonney Wind Farm Stage 2 output in MW
C5	=	-0.75
LB3	=	Lake Bonney Wind Farm Stage 3 output in MW
C6	=	-0.75
Snug	=	Snuggery Power Station output in MW
C7	=	-0.52
SALGEN	=	South Australia's largest single in-service generator in MW (largest potential generation loss under a single credible contingency)
C8	=	-1.50
Const	=	927

Long term voltage stability transfer capability based on the South East – Tailem Bend 275 kV line contingency

SA import transfer capability [MW] = C1*SESA DEM + C2*LAD + C3*LB1 + C4*CAN + C5*LB2 + C6*LB3 + C7*SNUG + CONST

Where:

SESA DEM	=	total South East Region demand in MW (Keith, Kincraig, Snuggery, Blanche, Mt Gambier, Penola West)
C1	=	1.27
Lad	=	Ladbroke Grove Power Station output in MW
C2	=	-0.65
LB1	=	Lake Bonney Wind Farm Stage 1 output in MW
C3	=	-0.88
Can	=	Canunda Wind Farm output in MW
C4	=	-0.85
LB2	=	Lake Bonney Wind Farm Stage 2 output in MW
C5	=	-0.92
LB3	=	Lake Bonney Wind Farm Stage 3 output in MW
C6	=	-0.92
Snug	=	Snuggery Power Station output in MW
C7	=	-1.58
Const	=	720

Short term voltage stability transfer capability based on the South East – Tailem Bend 275 kV line contingency

SA import transfer capability [MW] = C1*SESA DEM + C2*LAD + C3*LB1 + C4*CAN + C5*LB2 + C6*LB3 + C7*SNUG + CONST

Where:

SESA DEM	=	total South East Region demand in MW (Keith, Kincraig, Snuggery, Blanche, Mt Gambier, Penola West)
C1	=	1.71
Lad	=	Ladbroke Grove Power Station output in MW
C2	=	-0.33
LB1	=	Lake Bonney Wind Farm Stage 1 output in MW
C3	=	-0.84
Can	=	Canunda Wind Farm output in MW
C4	=	-0.96
LB2	=	Lake Bonney Wind Farm Stage 2 output in MW
C5	=	-1.01
LB3	=	Lake Bonney Wind Farm Stage 3 output in MW
C6	=	-1.01
Snug	=	Snuggery Power Station output in MW
C7	=	-1.38
Const	=	680

Short term voltage stability transfer capability based on the South East – Tailem Bend 275 kV line contingency

SA import transfer capability [MW] = C1*SESA DEM + C2*LAD + C3*LB1 + C4*CAN + C5*LB2 + C6*LB3 + C7*SNUG + 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	=	1.11
LB1	=	Lake Bonney Wind Farm Stage 1 output in MW
C3	=	0.81
Can	=	Canunda Wind Farm output in MW
C4	=	0.78
LB2	=	Lake Bonney Wind Farm Stage 2 output in MW
C5	=	0.72
LB3	=	Lake Bonney Wind Farm Stage 3 output in MW
C6	=	0.72
Snug	=	Snuggery Power Station output in MW
C7	=	1.74
Const	=	782

D2 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 include the Murraylink interconnector flow term, assuming system normal conditions.

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

D2.1 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 Murraylink interconnector 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 this factor limits the amount of real power that can be supplied into South Australia by Murraylink.

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.

D2.2 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 and equipment ratings and 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 or other stability limitations which govern the Murraylink interconnector transfer capability into South Australia.

Appendix E Fault levels and circuit breaker ratings

We have estimated the three-phase and single phase-to-ground fault levels under the 10% POE loading conditions for the South Australian transmission system (Table E-1). The fault level interruption capacity of the lowest rated circuit breaker(s) at each location should be taken only as a guide.

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. Fault levels may be higher than shown at some locations, predominantly due to the impact of embedded generation. 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.

The following assumptions were made when calculating maximum 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, Whyalla, Canunda and KCA is online
- system normal network configuration – all network elements are in service.

The following assumptions were made when calculating minimum fault levels:

- solid fault condition (i.e. no fault impedance modelled)
- depending on the type of wind farm, their contribution has been either assumed to be zero, or limited to their active power rating
- embedded generation is offline
- system normal network configuration – all network elements are in service (this means that fault levels could be lower under network element outage conditions).

Table E-1: Circuit breaker ratings and system fault levels

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating (kA)	2016-17 Maximum Fault Level (kA)		Minimum Fault Level (kA) 2 x GTs		Minimum Fault Level (kA) No GTs	
			3 phase	1 phase	3 phase	1 phase	3 phase	1 phase
Angas Creek	132	31.5	4.9	4.6	3.5	3.7	2.7	3.0
Angas Creek	33	13.1	5.3	6.6	4.7	6.0	4.4	5.7
Ardrossan West	132	21.9	2.6	2.6	1.4	1.6	1.2	1.5
Ardrossan West	33	17.5	4.5	3.4	3.2	2.8	3.0	2.7
Baroota	132	4.4	3.4	3.1	2.3	2.4	1.9	2.1
Baroota	33	17.5	1.6	1.7	1.5	1.6	1.4	1.6
Belalie	275	31.5	5.7	4.0	2.2	2.2	1.5	1.7
Berri	132	10.9	2.7	3.1	1.8	2.1	1.6	1.9
Berri	66	21.9	4.3	5.5	3.1	3.8	2.8	3.4

Location	Bus Voltage (kV)	Circuit Breaker Lowest	2016-17 Maximum Fault Level (kA)		Minimum Fault Level (kA) 2 x GTs		Minimum Fault Level (kA) No GTs	
Berri	11	20	11.5	9.7	9.1	7.4	8.7	7.1
Back Callington	132	31.5	4.7	4.0	3.5	3.4	2.7	2.8
Back Callington	11	25	9.0	0.6	8.5	0.6	8.2	0.6
Black Range	275	40	6.5	3.6	4.7	3.2	3.8	2.9
Black Range	275	40	8.6	4.2	4.2	3.1	2.5	2.4
Blanche	132	21.9	5.5	5.6	3.6	4.0	3.3	3.8
Blanche	33	17.5	8.4	11.4	6.9	9.5	6.7	9.3
Blyth	275	31.5	5.3	4.8	2.4	2.8	1.6	2.0
Brinkworth	275	21	5.0	4.0	2.3	2.5	1.6	1.8
Brinkworth	132	15.3	7.9	8.8	4.0	5.0	2.9	3.8
Brinkworth	33	17.5	3.0	3.7	2.7	3.4	2.6	3.3
Bungama	275	31.5	5.2	4.4	2.3	2.5	1.5	1.9
Bungama	132	10.9	7.0	8.0	3.6	4.7	2.7	3.6
Bungama	33	13.1	10.6	6.5	7.9	5.7	6.9	5.4
Canowie	275	31.5	7.5	5.4	2.2	2.5	1.5	1.9
Cherry Gardens	275	31.5	13.1	13.4	4.0	5.2	2.1	2.9
Cherry Gardens	132	15.3	7.2	7.6	4.6	5.5	3.3	4.1
City West	275	40	14.4	17.8	4.0	5.4	2.0	2.8
City West - CBD	66	40	22.6	21.9	11.4	13.1	7.1	9.0
City West - South	66	40	19.0	13.7	10.5	9.8	6.9	7.4
Clare North	132	40	6.8	6.8	3.5	3.9	2.6	3.2
Clare North	33	31.5	9.5	7.0	7.1	5.9	6.3	5.6
Cultana	275	31.5	4.9	4.8	2.0	2.5	1.5	1.9
Cultana	132	31.5	6.7	7.1	3.2	4.0	2.5	3.3
Dalrymple	132	40	2.2	2.2	0.9	1.1	0.8	1.0
Dalrymple	33	8	4.1	5.5	2.5	3.4	2.3	3.3
Davenport	275	31.5	7.0	7.3	2.4	3.1	1.6	2.2
Davenport	132	40	7.4	8.5	3.7	4.8	2.8	3.8
Davenport	33	31.5	9.5	9.5	7.2	7.9	6.4	7.3
Dorrien	132	21.9	7.2	7.4	4.0	4.7	2.9	3.6
Dorrien	33	17.5	15.6	10.5	9.3	8.1	7.8	7.4
Dry Creek_West	66	21.9	20.9	18.0	9.8	9.5	6.5	7.2
Dry Creek_East	66	21.9	20.3	18.8	9.8	9.1	6.5	7.0
East Terrace	275	N/A	12.8	13.6	3.9	5.0	2.0	2.8
East Terrace	66	31.5	23.9	23.2	11.7	13.5	7.2	9.2

Location	Bus Voltage (kV)	Circuit Breaker Lowest	2016-17 Maximum Fault Level (kA)		Minimum Fault Level (kA) 2 x GTs		Minimum Fault Level (kA) No GTs	
Happy Valley	275	31.5	12.7	13.2	4.0	5.1	2.1	2.9
Happy Valley	66	21.9	26.0	22.6	12.3	13.7	7.6	9.0
Hummocks	132	10.9	4.1	4.1	2.2	2.5	1.8	2.2
Hummocks	33	17.5	4.8	4.7	3.7	3.9	3.5	3.8
Kadina East	132	40	2.3	2.6	1.5	1.9	1.3	1.7
Kadina East	33	17.5	5.8	4.4	4.4	3.7	4.0	3.6
Kanmantoo	132	10.9	4.9	4.2	3.6	3.5	2.8	3.0
Kanmantoo	33	N/A	1.6	1.7	1.6	1.7	1.5	1.6
Kanmantoo	11	13.1	3.9	2.4	3.8	2.4	3.7	2.3
Keith	132	15.3	2.2	2.1	1.9	1.9	1.8	1.8
Keith	33	31.5	4.0	5.1	3.7	4.9	3.6	4.7
Kilburn	275	31.5	15.7	16.4	4.0	5.3	2.0	2.8
Kilburn	66	21.9	20.9	18.0	9.8	9.5	6.5	7.2
Kincraig	132	15.3	2.6	2.6	2.1	2.2	2.0	2.1
Kincraig	33	17.5	4.3	6.0	3.9	5.4	3.8	5.3
Le Fevre	275	40	19.7	23.4	4.2	5.7	2.1	2.9
Le Fevre	66	25	29.7	27.5	11.4	12.5	7.1	8.7
Leigh Creek Coalfield	132	N/A	0.6	0.8	0.6	0.7	0.5	0.7
Leigh Creek Coalfield	33	8.7	1.5	2.2	1.5	2.1	1.4	2.0
Leigh Creek South	132	N/A	0.6	0.8	0.6	0.7	0.6	0.7
Leigh Creek South	33	18.4	1.0	1.3	0.9	1.3	0.9	1.2
Magill	275	15.7	14.2	14.8	4.0	5.2	2.1	2.8
Magill	66 (1)	21.9	23.7	27.8	11.7	15.3	7.2	9.9
Magill	66 (2)	21.9	12.0	8.3	8.0	6.7	5.8	5.3
Mannum	132	40	5.0	4.9	3.7	3.9	2.8	3.3
Mannum	33	31.5	5.2	4.9	4.7	4.6	4.4	4.4
Mannum – Adelaide Pump 1	132	N/A	4.5	4.0	3.4	3.4	2.7	2.9
Mannum – Adelaide Pump 1	3.3	N/A	25.4	25.3	24.7	24.9	23.9	24.4
Mannum – Adelaide Pump 2	132	N/A	4.7	4.1	3.5	3.4	2.7	2.9
Mannum – Adelaide Pump 2	3.3	N/A	25.5	25.5	24.7	25.0	23.9	24.5

Location	Bus Voltage (kV)	Circuit Breaker Lowest	2016-17 Maximum Fault Level (kA)		Minimum Fault Level (kA) 2 x GTs		Minimum Fault Level (kA) No GTs	
Mannum – Adelaide Pump 3	132	N/A	4.7	4.0	3.4	3.3	2.7	2.8
Mannum – Adelaide Pump 3	3.3	N/A	25.5	25.5	24.7	25.0	23.8	24.4
Mayurra	132	40	7.4	5.8	3.0	2.9	2.8	2.8
Middleback	132	40	2.9	2.6	1.6	1.7	1.4	1.6
Middleback	33	N/A	1.5	2.1	1.4	1.9	1.4	1.9
Millbrook	132	10.9	5.3	4.7	3.6	3.7	2.7	3.0
Millbrook	3.3	N/A	18.0	18.2	17.4	17.8	17.0	17.5
Mintaro	132	20	8.0	8.3	3.7	3.8	2.7	3.1
Mobilong	132	15.3	6.1	6.3	4.3	4.8	3.2	3.9
Mobilong	33	31.5	9.3	7.0	8.0	6.4	7.1	6.1
Mokota	275	50	6.2	4.3	2.3	2.4	1.6	1.8
Monash	132	31.5	2.8	3.3	1.9	2.2	1.7	2.0
Monash	66	N/A	4.2	5.5	3.0	3.8	2.7	3.4
Morgan – Whyalla Pump 1	132	15.3	4.5	4.4	2.9	3.0	2.3	2.6
Morgan – Whyalla Pump 1	3.3	N/A	27.3	27.5	23.9	24.4	23.1	23.9
Morgan – Whyalla Pump 2	132	15.3	5.1	4.3	3.2	3.0	2.5	2.6
Morgan – Whyalla Pump 2	3.3	N/A	19.0	19.0	17.3	17.4	16.8	17.2
Morgan – Whyalla Pump 3	132	15.3	8.1	7.1	4.2	4.4	3.0	3.5
Morgan – Whyalla Pump 3	3.3	N/A	19.4	19.5	17.8	18.2	17.4	17.9
Morgan – Whyalla Pump 4	132	15.3	9.8	8.6	4.5	4.9	3.2	3.7
Morgan – Whyalla Pump 4	3.3	N/A	19.4	19.7	17.9	18.4	17.5	18.1
Morphett Vale East	275	31.5	11.7	11.8	3.9	4.9	2.1	2.8
Morphett Vale East	66	25	22.0	17.4	11.0	11.3	7.1	8.0
Mount Barker	132	31.5	6.7	6.7	4.4	4.9	3.2	3.9
Mount Barker	66	31.5	11.3	11.9	7.9	9.1	5.9	7.3
Mount Barker South	275	40	11.2	10.5	3.9	4.7	2.1	2.8
Mount Barker South	66	66	11.5	11.4	8.0	8.8	6.0	7.1

Location	Bus Voltage (kV)	Circuit Breaker Lowest Rating	2016-17 Maximum Fault Level (kA)		Minimum Fault Level (kA) 2 x GTs		Minimum Fault Level (kA) No GTs	
Mount Gambier	132	15.3	6.8	6.6	4.4	4.9	4.1	4.6
Mount Gambier	33	17.5	7.2	6.0	6.3	5.5	6.1	5.4
Mount Gunson	132	15.3	1.1	1.1	0.9	1.0	0.9	1.0
Mount Gunson	33	N/A	1.3	1.3	1.2	1.2	1.2	1.2
Mount Millar	132	40	2.2	1.7	0.7	0.8	0.7	0.8
Mount Millar	33	31.5	10.3	1.4	2.3	1.2	2.2	1.2
Munno Para	275	40	12.6	11.6	3.8	4.7	2.0	2.7
Munno Para	66	40	14.1	10.6	8.8	8.0	6.1	6.5
Murray – Hahndorf Pump 1	132	15.3	5.3	5.2	3.9	4.2	3.0	3.4
Murray – Hahndorf Pump 1	11	N/A	12.7	13.1	12.0	12.6	11.3	12.1
Murray – Hahndorf Pump 2	132	15.3	5.9	5.6	4.2	4.4	3.1	3.6
Murray – Hahndorf Pump 2	11	N/A	12.9	13.3	12.2	12.8	11.5	12.3
Murray – Hahndorf Pump 3	132	15.3	5.7	5.2	4.0	4.1	3.0	3.4
Murray – Hahndorf Pump 3	11	N/A	13.0	13.2	12.2	12.7	11.5	12.2
Neuroodla	132	N/A	1.5	1.4	1.2	1.2	1.1	1.2
Neuroodla	33	8.7	1.4	1.4	1.3	1.3	1.3	1.3
New Osborne	66	40	31.9	31.0	11.5	12.5	7.1	8.7
North West Bend	132	10.9	4.5	4.7	2.9	3.1	2.3	2.7
North West Bend	66	13.1	4.7	5.3	3.5	4.0	3.1	3.7
Northfield	275	31.5	15.5	15.7	4.0	5.2	2.0	2.8
Northfield	66	31.5	27.7	24.8	12.3	13.6	7.4	9.2
Para	275	31.5	18.3	20.5	4.2	5.7	2.1	2.9
Para	132	21.9	8.5	9.0	4.8	5.8	3.3	4.2
Para	66	21.9	18.6	15.7	10.4	10.8	6.8	8.0
Para	11 (SVC)	N/A	32.8	28.4	28.0	24.2	24.3	21.0
Parafield Gardens West	275	31.5	16.6	18.1	4.1	5.4	2.1	2.8
Parafield Gardens West	66	31.5	18.5	15.4	10.3	10.6	6.8	7.9
Pelican Point	275	40	19.5	22.8	4.2	5.6	2.1	2.8
Penola West	132	31.5	5.1	5.8	3.3	3.2	3.0	3.1
Penola West	33	31.5	5.3	5.4	4.6	4.5	4.5	4.5

Location	Bus Voltage (kV)	Circuit Breaker Lowest	2016-17 Maximum Fault Level (kA)		Minimum Fault Level (kA) 2 x GTs		Minimum Fault Level (kA) No GTs	
Pimba	132	31.5	0.9	0.9	0.8	0.9	0.7	0.8
Playford	275	10.5	6.7	6.9	2.4	3.0	1.6	2.1
Playford	132	10.9	4.4	4.8	2.8	3.4	2.3	2.9
Port Lincoln Terminal	132	10.9	2.7	3.0	0.5	0.7	0.5	0.7
Port Lincoln Terminal	33	17.5	6.5	5.1	1.8	2.1	1.7	2.0
Port Lincoln Terminal	11	13.1	9.0	7.7	4.1	3.5	4.0	3.4
Port Pirie	132	40	5.6	5.9	3.2	3.8	2.5	3.1
Port Pirie	33	13.1	8.9	5.3	6.9	4.7	6.1	4.5
Redhill	132	N/A	6.6	5.4	3.5	3.6	2.6	3.0
Robertstown	275	31.5	9.3	7.4	2.9	3.4	1.8	2.3
Robertstown	132	31.5	10.9	11.0	4.8	5.7	3.3	4.2
Roseworthy	132	31.5	7.3	6.2	4.2	4.3	3.0	3.4
Roseworthy	11	25	9.0	12.5	8.4	11.6	8.1	11.2
Sleaford	132	40	2.4	1.8	0.5	0.6	0.5	0.6
Snowtown	132	N/A	4.4	3.1	2.2	2.1	1.8	1.8
Snuggery	132	10.9	8.5	8.9	3.4	3.8	3.2	3.7
Snuggery (Industrial)	33	8.7	13.1	16.6	6.4	8.8	6.2	8.6
Snuggery (Industrial)	11 (Cap)	13.1	12.6	10.9	9.2	8.0	9.0	7.8
Sunggery (Rural)	33	8.7	3.5	4.7	3.0	4.1	3.0	4.1
Snuggery (Rural)	11 (Cap)	13.1	5.7	5.0	5.4	4.6	5.3	4.6
South East	275	31.5	8.7	8.6	5.9	6.5	4.8	5.6
South East	132	20	10.8	11.8	6.3	7.7	5.7	7.0
Stony Point	132	31.5	3.6	2.8	2.3	2.1	1.9	1.9
Stony Point	11	N/A	9.7	0.3	8.6	0.3	8.3	0.3
Tailem Bend	275	21	8.5	5.9	4.2	4.1	2.6	3.0
Tailem Bend	132	21.9	6.7	7.7	4.9	5.9	3.6	4.7
Tailem Bend	33	25	5.9	7.6	5.4	7.0	5.1	6.6
Templers	132	10.9	7.8	7.4	4.3	4.8	3.0	3.7
Templers	33	8.7	10.1	7.3	7.9	6.4	6.9	6.0
Templers West	275	31.5	8.4	7.3	3.2	3.7	1.8	2.4
Templers West	132	40	7.4	7.1	4.3	4.8	3.0	3.7
Quarantine 1	66	N/A	14.5	14.0	7.3	6.3	5.3	5.3

Location	Bus Voltage (kV)	Circuit Breaker Lowest	2016-17 Maximum Fault Level (kA)		Minimum Fault Level (kA) 2 x GTs		Minimum Fault Level (kA) No GTs	
Quarantine 2	66	N/A	16.6	12.9	7.9	6.5	5.6	5.4
Torrens Island	275	31.5	20.7	25.7	4.3	5.9	2.1	2.9
Torrens Island	66	40	32.2	30.9	11.6	12.9	7.1	8.9
Tungkillo	275	50	12.6	10.8	4.0	4.8	2.2	2.9
Waterloo	132	10.9	10.0	8.7	4.3	4.6	3.0	3.5
Waterloo	33	13.1	6.2	4.4	5.1	3.9	4.7	3.7
Waterloo East	132	N/A	9.9	8.1	4.2	4.4	3.0	3.5
Whyalla Central	132	40	6.0	6.4	3.0	3.7	2.4	3.1
Whyalla Central	33	40	14.8	8.2	7.6	6.1	6.8	5.8
Whyalla Terminal (LMF)	132	10.9	5.8	6.1	2.9	3.6	2.4	3.1
Whyalla Terminal (LMF)	33	17.5	4.7	4.6	4.1	4.2	3.9	4.1
Wudinna	132	31.5	1.0	1.1	0.6	0.7	0.5	0.7
Wudinna	66	21.9	1.5	1.8	1.0	1.2	0.9	1.2
Yadnarie	132	10.9	2.6	2.5	0.9	1.1	0.8	1.1
Yadnarie	66	40	2.7	3.2	1.4	1.8	1.3	1.7
Yadnarie	11 (Reactor)	18.4	6.3	5.5	4.6	4.0	4.5	3.9

Appendix F Network support solutions

In accordance with clause 5.12.1(b).4 of the Rules, ElectraNet considers potential network support solution options on an equal basis with network options for addressing network limitations or constraints.

F1 Network support solutions framework

ElectraNet's network support solutions framework facilitates a timely, efficient, and transparent transmission planning process. It defines ElectraNet's commitment to develop and maintain reliable and cost efficient solutions to address network limitations or constraints. The merits of network support solutions, either stand-alone or combined with network solutions, are considered equally.

ElectraNet seeks proposals from non-network solution providers for potentially viable non network options, and considers the merits of all proposals received. This includes detailed assessment of technical feasibility, timelines, and efficiency. If a network support solution option is shown to be the most cost effective technically viable solution, then a network support agreement is negotiated with the proponent.

F2 Network support solutions planning assessment

Network support options are assessed according to their ability to:

- provide a level of net demand reduction that will resolve the identified limitation
- 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)
- be provided at the lowest net present value (NPV) cost
- provide reliable demand reduction.

Options that are able to be delivered in time to meet the identified network need are ranked from lowest to highest NPV in terms of cost per megawatt. The options can be considered individually or combined with other options. A network support 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.

For 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.

F3 Projects for potential network support solutions

Recently completed, in-progress, and planned consultations for forecast limitations on which ElectraNet has sought or seeks proposals for network support solutions are outlined in Table F-1.

Table F-1: Planned projects for which ElectraNet seeks or has sought proposal for network support solutions

Project	Expected project commitment date	Consultation status
Managing Main Grid High Voltage Levels Refer to sections 8.7.1 to 8.7.4 of this report	Early 2018, for first stage completion in late 2018	Declining levels of minimum demand are forecast to reach levels from spring 2018 that may result in voltage levels on the Main Grid that exceed equipment ratings if a credible contingency event was to occur at low demand times A PSCR is planned to be published in the second half of 2017
Eyre Peninsula Electricity Supply Options Refer to section 8.4.1	2018, for completion by 2022	The current network support arrangement that enables ElectraNet to meet the ETC category 3 reliability standard at Port Lincoln expires in December 2018, and significant portions of the conductor on the Eyre Peninsula 132 kV lines are in poor condition ElectraNet is currently considering the best way to continue to meet the ETC category 3 reliability standard at Port Lincoln and address the poor conductor condition The PSCR was published in April 2017 and remains open for consultation until 21 July 2017[53]
South Australian Energy Transformation Refer to section 8.3.2 of this report	2018, for completion in 2021 or later	ElectraNet is investigating the feasibility of an additional interconnector between South Australia and the Eastern States, as outlined in the PSCR published in November 2016[54] A PADR is planned to be published in the second half of 2017
Gawler East New Connection Point Refer to section 8.4.2 of this report	2021, for completion in 2022	Application of the RIT-D is planned to begin with publication by SA Power Networks of a NNOR for this project well before project commitment Proponents of potential network support solutions will be encouraged to make a submission in response to the NNOR

53 Available from electranet.com.au.
54 Available from electranet.com.au.

Appendix G Committed, pending, proposed and potential projects

Emerging network limitations and solution options have been identified during scenario analysis Table G1. The committed, pending and proposed solutions are 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. We've also included committed, pending and proposed projects already covered in chapters 7 and 8 to provide a complete overview of all augmentation and market benefit projects.

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 timing and scope of projects are indicative only.

ElectraNet also has a range of committed, pending and proposed projects that relate to the maintenance of ElectraNet's security and compliance obligations Table G2, including the security and compliance projects already covered in section 7.2.

There are many significant asset replacement projects (>$3M at a single site) proposed, which are planned based on asset condition Table 0, including the projects already covered in chapter 8. Currently there are no economically feasible non-network solutions that could resolve the limitations presented.

ElectraNet has assessed detailed asset condition and replacement requirements for the 2018-19 to 2022-23 regulatory control period. Summary entries for line, substation and protection system unit asset replacements are provided. These summaries relate to types of projects that we have included in our 2018-19 to 2022-23 revenue proposal, which we submitted to the AER in March 2017.

Contingent projects that that we have included in out 2018-19 to 2022-23 revenue proposal are listed in Table G-4.

G1 Summary of committed, pending, proposed and potential augmentation projects

Table G-1: Committed, pending and proposed and potential augmentation projects

Project timing	Limitation	Proposed solution	Category	Region	$ million
Committed and Pending Projects					
2017	Heywood Interconnector transfer limitations due to system stability and thermal constraints	Minor works outstanding, including implementation of control scheme to bypass the capacitors under certain conditions	Augmentation and market benefit	Main Grid and South East	35-45 (ElectraNet costs only)
2017	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 implementation of dynamic line ratings on critical circuits	Augmentation and market benefit	Various	<5
2017	Congestion on the 132 kV network between Robertstown and Monash restricts 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	Market benefit (NCIPAP)	Riverland	<5
2017 (subject to receipt of ARENA grant)	Large scale renewable energy sources connected to the transmission network are intermittent and do not contribute to frequency control to the same extent as conventional generation, causing potential frequency control issues that may threaten South Australian system security at times when few conventional generators are dispatched	Design and build a grid-connected, utility scale battery energy storage system at Dalrymple that will help to manage frequency related system security issues, as well as improve the reliability of supply for customers at Dalrymple connection point and provide other market benefits	Augmentation and market benefit	Mid North	5-8 (ElectraNet costs only)
2018	Congestion on the 132 kV network between Waterloo East and Robertstown restricts exports from South Australia to Victoria across the Murraylink Interconnector	Uprate the Waterloo East – Robertstown 132 kV line to 100˚C line clearances	Market benefit (NCIPAP)	Mid North	<5
Proposed Projects					
2018	Low rated plant at Templers substation constrains power flows in the Mid North region	Upgrade Templers 132 kV bus and primary plant to carry a minimum current of 1600 A	Augmentation	Mid North	<5

Project timing	Limitation	Proposed solution	Category	Region	$ million
2018	Difficulty in manually and effectively controlling the increasing number of reactive plant and voltage control facilities across the Main Grid	Install a coordinated control scheme to better use existing reactive plant and voltage control facilities to minimise system constraints, whilst managing system voltage levels	Augmentation	Main Grid/ Various	<5
2019	Thermal congestion across the Heywood interconnector between Tailem Bend and Tungkillo and between Tailem Bend and Mobilong when the interconnector is limited below 650 MW	Apply dynamic ratings to the key circuits that make up the Heywood interconnector in South Australia to better account for favourable weather conditions and release further transfer capacity	Market benefit (NCIPAP)	Main Grid	<5
2019	Substation plant and secondary system ratings limit full utilisation of the Davenport-Robertstown 275 kV transmission lines thermal capacity	Remove, replace or change plant and secondary systems that are rated lower than the design capability of the conductors	Market benefit (NCIPAP)	Main Grid	<5
2020	Congestion on the Waterloo-Templers 132 kV line limits power flows in the Mid North region	Install power flow control technology that will increase impedance of the Waterloo-Templers 132 kV line and thereby improve overall transfer capacity by increasing power flows on lines with surplus capacity	Market benefit (NCIPAP)	Mid North	3-6
2020	Transient (rotor angle) and voltage stability limit the inter-regional transfer capacity of the Heywood interconnector	Turn the Tailem Bend - Cherry Gardens 275 kV line into Tungkillo substation, fully populating the diameter that is benched and prepared ready for this	Market benefit (NCIPAP)	Main Grid	4-8
2021	Voltage limitations around South East substation prevent the full thermal capacity of the Heywood interconnection corridor being utilised	Install an additional 100 Mvar capacitor at South East substation	Market benefit (NCIPAP)	Main Grid	<5
2022	Thermal design ratings of the Robertstown 275/132 kV transformers limit transfer capability across the Murraylink interconnector	Install new transformer management relays and bushing monitoring add-on equipment and apply short term ratings to the two 275/132 kV transformers at Robertstown (NCIPAP)	Market benefit (NCIPAP)	Mid North / Murraylink Inter-connector	<5

Project timing	Limitation	Proposed solution	Category	Region	$ million
2022	Expiry of existing contract for network support at Port Lincoln Significant lengths of conductor on the Whyalla to Yadnarie and the Yadnarie to Port Lincoln 132 kV lines are in poor condition and need to be replaced	Construct new double circuit lines from Cultana to Yadnarie and from Yadnarie to Port Lincoln, and decommission the existing 132 kV lines	Augmentation (Contingent)	Eyre Peninsula	200-550
2022	Significant residential developments near Gawler that cannot be supplied by SA Power Networks' existing distribution network in the area	Establish a new 132 kV exit point on the Para – Roseworthy 132 kV line at Gawler East to provide supply to a 132/11 kV distribution substation that will be constructed and owned by SA Power Networks	Connection	Mid North	3-6 (ElectraNet costs only)
2024-2028	Constraints applied to generation connected to Davenport-Robertstown 275 kV transmission lines	Uprate selected spans to achieve T120 rating, uprate protection and metering systems, and implement calculation of real-time ratings	Market benefit	Main Grid	<5
2024-2028	Transient (rotor angle) and voltage stability limit the inter-regional transfer capacity of the Heywood interconnector	Turn the Robertstown - Para 275 kV line into Tungkillo substation, fully populating the diameter that is benched and prepared ready for this	Market benefit	Main Grid	4-8
Potential Projects					
When or if needed: 2021 or after	Facilitate greater competition in the wholesale electricity market, provide appropriate security of supply, and facilitate the transition to lower carbon emissions	Establish a new high capacity interconnector between South Australia and the eastern states, or implement a range of network support solutions	Market benefit (Contingent)	Main Grid	200 – 500 (SA component only)
When or if needed: by 2027?	Connection of a step load increase that could cause the line loading to exceed its thermal limit of 76 MVA	Rebuild the Davenport to Pimba 132 kV line and establish associated substation assets (including reactive support)	Augmentation (Contingent)	Upper North	110
When or if needed: by 2027?	Connection of a step load increase that could cause the line loading to exceed its thermal limit of 10 MVA	Uprate or rebuild the Davenport to Leigh Creek 132 kV line and establish associated substation assets (including reactive support)	Augmentation (Contingent)	Upper North	60

G2 Summary of committed, pending and proposed security and compliance projects

Table G-2: Committed, pending and proposed security and compliance projects

Project timing	Limitation	Proposed solution	Region	$ million
Committed and Pending Projects				
2017	Uncontrolled tripping of SA generation due to over-frequency could lead to significant loss of frequency control capability in SA	Implement Over-frequency Generation Shedding (OFGS) scheme for SA wind farms, including a backup scheme on the network side of the wind farm connections	Various	<5
2017	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 and secondary systems, and rearrange 275 kV line exits	Main Grid	8-10
2017	Transformer oil containment systems need refurbishing in accordance 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	8–10
2018	Changing generation patterns have resulted in complex voltage interactions in 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	Spencer Gulf high tower crossings for the Davenport-Cultana 275 kV transmission lines, supplying the entire Eyre Peninsula region, would prove difficult or impossible to restore to in a timely manner following an asset failure	Undertake preparatory site works and procure spares to support a rapid restoration	Eyre Peninsula	<5
2018	The Heywood interconnector is constrained during an outage of the existing single 275/132 kV transformer at Tailem Bend substation	Install, connect and commission the spare 160 MVA 275/132 kV transformer as a second transformer on hot standby at Tailem Bend substation	South East	<5
2018	High voltage hazard due to lack of remote visibility of manually operated isolator and earth switch status	Install status indication on isolators and earth switches where there currently is none	Various	<5

Project timing	Limitation	Proposed solution	Region	$ million
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	4-8
2018	Existing backups for ElectraNet's control centre and data centre requirements require improvement to address emerging security threats	Construct a new Backup Control and Data Centre to meet current physical and electronic security requirements	Metropolitan	4-8
2018	Following a single contingency of an in-service generator, steady-state voltage levels on the South Australian transmission system may breach 110% of the nominal 275 kV at times of light load, high solar PV generation and low wind generation from 2018	Install a switched 50 Mvar 275 kV reactor at Templers West substation	Main Grid	<5
2019	High voltage hazard due to risk of failure of mechanical or electrical lock-off points on motorised air insulated high voltage isolators	Replace or refurbish mechanical and electrical isolation lock-off points on all motorised air insulated isolators	Various	10-15
2019	Geomagnetic induced currents resulting from enhanced solar activity may induce DC currents on transmission lines and possible transformer damage or failure	Install protective monitoring and alarming to enable affected transformers to be tripped prior to serious damage occurring	Various	<5
2019	Failure of Gas Insulated Switchgear (GIS) plant at Kilburn substation places significant load at risk from the next single contingency	Design, procure and have on standby the necessary line components to bypass Kilburn substation	Metropolitan	<5
2019	Unavailability of Gas Insulated Switchgear (GIS) connection spares hinders restoration of supply following a 225 MVA 275/66 kV transformer failure at East Terrace, Northfield or Kilburn substation	Design and procure all the plant and equipment required to support the rapid restoration of a failed GIS-connected 225 MVA 275/66 kV transformer	Metropolitan	<5
2019	Loss of AC auxiliary supplies hinders restoration of supply during black start or other abnormal operating conditions	Provide alternative diesel generator supplies to critical substations (where not already provided), connection points for mobile generators to non-critical substations, and related AC and DC supply improvements	Various	5-10
2019	Inadequate access tracks in difficult terrain hinder inspection and restoration of transmission lines following a fault	Upgrade transmission line access tracks at vulnerable locations across the network	Various	<5

Project timing	Limitation	Proposed solution	Region	$ million
2019	Loss of multiple generators and/or islanding of South Australia from the remainder of the NEM puts SA system security at risk from loss of synchronism	Implement a Special Protection Scheme (SPS) and Wide Area Monitoring Scheme (WAMS) utilising transmission-level load tripping and phasor measurement capabilities	Various	4-8
2020	Either Murraylink interconnection or generation north of Robertstown must be constrained during scheduled maintenance of centre breakers or associated plant at the Robertstown substation	Install a single 275 kV circuit breaker and associated equipment between the 275 kV busses at the Robertstown substation	Mid North / Murraylink Inter-connector	5–8
2021	Generator disconnection 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	Mid North	<5
2021	Following a single contingency of an in-service generator, steady-state voltage levels on the South Australian transmission system may breach 110% of the nominal 275 kV at times of light load, high solar PV generation and low wind generation from 2021	Install a switched 50 Mvar 275 kV reactor at Blyth West substation	Main Grid	<5
When or if needed	Minimum fault levels in South Australia may fall below the level that is needed to ensure the ongoing stable operation of South Australia's electricity system	Upgrade existing protection devices and install six synchronous condensers at selected locations across the 275 kV transmission network	Main Grid	60-80
2023	Following a single contingency of an in-service generator, steady-state voltage levels on the South Australian transmission system may breach 110% of the nominal 275 kV at times of light load, high solar PV generation and low wind generation from 2023	Install a switched 50 Mvar 275 kV reactor at Para substation	Main Grid	<5
2023	Risk of thermal damage to neutral earthing reactors and resistors, and consequent unsafe operating conditions and risk of damage to larger plant	Install a monitoring and protection scheme for the neutral earthing reactor and resistor installations across the network	Various	<5
2023	Operational difficulties with starting Quarantine Power Station #5 generator during black start conditions	Install a 66 kV circuit breaker and associated equipment to tie the two Torrens Island North lines in the Torrens Island North 66 kV switchyard	Metropolitan	<5

Project timing	Limitation	Proposed solution	Region	$ million
2027	Following a single contingency of an in-service generator or significant reactive control plant, steady-state voltage levels on the South Australian transmission system may breach 110% of the nominal 275 kV at times when minimum system demand drops to below zero due to high rooftop solar PV generation from 2027	Install a switched 50 Mvar 275 kV reactor in the Mid North region	Main Grid	<5
2024–2028	Generation constraints and/or loss of load during plant outages at the Blanche substation	Install an additional 132 kV circuit breaker and associated equipment at the Blanche substation	South East	<5
2024–2028	Mintaro and Angaston generators are constrained off during 132 kV outages that result in these generators being radialised	To be considered for 2024-2028 NCIPAP Implement full single pole reclosing capability on the 132 kV circuits in the Mid North region	Mid North	<5
2024–2028	Ladbroke Grove and Snuggery generators are constrained off during 132 kV outages that result in these generators being radialised	To be considered for 2024-2028 NCIPAP Implement full single pole reclosing capability on the 132 kV circuits in the South East region	South East	<5

G3 Summary of committed, pending and proposed asset replacement projects

Table G-3: Committed, pending and proposed asset replacement projects

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
Committed and Pending Projects					
2017	Morgan to Whyalla pumping station #4 primary plant is at end-of-technical-life and the site is not aligned with current environmental practices and company policies	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	10–13	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 is at end-of-technical-life and the site is 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	10–14	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 is at end-of-technical-life and the site is 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	10–14	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites
2017	A number of substation battery charger units have reached the end of their practical life. Spare parts are not available	Implement a planned replacement program to remove battery chargers from service and replace with modern, fit-for-purpose equipment	Various	<5	Replace battery chargers on failure

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
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	Mid North	5–8	Rebuild substation at a new location
2017	Porcelain disc insulators on the Brinkworth to Mintaro 132 kV line are at end-of-life, leading to a high failure rate and fire start risk	Replace all porcelain disc insulators, along with defective poles and cross arms, on the Brinkworth to Mintaro 132 kV line to achieve a 15-year life extension	Mid North	6–8	Assess and replace insulators on sample-based testing results
2017	Mannum to Adelaide pumping station #1 primary plant is at end-of-technical-life and the site is 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. Replace associated line assets that are in poor condition	Eastern Hills	15–20	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites
2018	Gas Insulated Switchgear (GIS) plant at East Terrace substation requires an effective monitoring system to mitigate operational and environmental risks associated with a gas leak	Replace existing combined phases gas monitoring system with isolated per phase systems	Metro-politan	<5	Install additional barriers for separate monitoring of gas compartments or Replace GIS plant
2018	Many items of online condition monitoring equipment are now 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

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
2018	Millbrook pumping station primary plant is at end-of-technical-life and the site is not aligned with current environmental practices and company policies	Rebuild the Millbrook pumping station 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	12–16	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites
2014-2018	Substation assets have been identified with high failure rates and safety risks or have been assessed to be at the end of their technical and economic lives	Program of unit asset replacements at multiple substations	Various	40-50	Replace individual assets on failure
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 11 substations	Various	8-12	Replacing sub-standard and hazardous equipment is considered to be the only viable option
2018	Operational risks and delays in protection and control systems at Monash and Berri substations	Replace protection relays and communication gateway	Riverland	<5	Replace communication gateway only
2018	Outages and constraints on the Murraylink Interconnector	Redesign and replace the Murraylink control scheme	Riverland / Murraylink Inter-connector	<5	Replace the Murraylink control scheme with no redesign
2018	Load-releasing cross arms on the Para-Brinkworth-Davenport 275 kV line are a safety risk and inadequate for access and maintenance. Porcelain disc insulators are at end-of-life, which can lead 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 to achieve a 15-year life extension	Main Grid	55-65	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 use sample-based testing results to assess and replace insulators

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
2019	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
2019	Risk of unplanned outages on Magill - East Terrace 275 kV underground cable	Replace degraded underground fluid instrumentation and associated telecommunications and infrastructure	Metro-politan	<5	Defer replacement and manage risk or Continue corrective maintenance program only
Proposed Projects					
2018	Davenport-Pimba 132 kV transmission line cannot safely achieve its designed nominal ratings at T65 operating temperature	Treat low spans to achieve the designed nominal ratings for Davenport – Mt Gunson section	Upper North	4-8	Treat low spans for Davenport – Mt Gunson – Pimba or Install grid support
2019	Transformer fire suppression systems at Magill substation have been identified as a safety hazard and asset risk	Investigate, design and install refurbished or replacement fire suppression systems	Metro-politan	<5	Replace fire suppression systems with no redesign
2019	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 two 5 MVA transformers with a single new 5 MVA 132/11 kV transformer and associated plant at Leigh Creek South substation	Upper North	<5	Replace asset on failure or Establish micro-grid
2021	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	<5	Replace asset on failure

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
2022	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 20 MVA transformers with two new 25 MVA 132/33 kV transformers (nearest ElectraNet standard transformer size) at Mannum substation	Eastern Hills	<5	Replace assets on failure
2022	South East SVC computer control system at end-of-life, leading to SVC reliability risk and interconnector constraints	Replace the existing SVC computer control system at South East substation with a new fully supported system	SA-Vic Inter-connector	4-8	Replace South East substation SVCs
2019–2023	Transmission line support systems (towers, poles) components at end-of-life, leading to a high failure rate, and safety and network availability risk	Refurbish transmission line support systems and extend the life of the Snuggery – Blanche – Mt Gambier 132 kV line by renewing line asset components	South East	8–10	Replace individual components or sections on failure or Full line replacement
2019–2023	Transmission line insulator systems at end-of-life, leading to a high failure rate, safety and network availability risk, and fire start risk	Implement a program of transmission line insulator system refurbishment to renew line asset components and extend line life	Various	50–70	Replace individual components or sections on failure or Full line replacement
2019–2023	Transmission line conductor and earthwire components at end-of-life, leading to a high failure rate, safety and network availability risk, and fire start risk	Implement a program of transmission line conductor and earthwire refurbishment to renew line asset components and extend line life	Mid North / Riverland	10–20	Replace individual corroded conductor sections or Full line replacement
2019–2023	Significant lengths of conductor on the Cultana to Yadnarie 132 kV line are in poor condition, leading to a high failure rate, safety and network availability risk, and fire start risk	Refurbish conductor and earthwire and extend the life of the Cultana to Yadnarie 132 kV transmission line	Eyre Peninsula	30–45	Replace individual corroded conductor sections or Full line replacement
2019–2023	Significant lengths of conductor on the Yadnarie to Port Lincoln 132 kV line are in poor condition, leading to a high failure rate, safety and network availability risk, and fire start risk	Refurbish conductor and earthwire and extend the life of the Yadnarie to Port Lincoln 132 kV transmission line	Eyre Peninsula	30–45	Replace individual corroded conductor sections or Full line replacement

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
2019–2023	Substation assets have been identified with high failure rates and, safety risks or have been assessed to be at the end of their technical and economic lives	Implement a program of unit asset replacement projects at various substations	Various	50–65	Replace assets on failure
2019–2023	Various individual substation protection and control systems have been assessed to be at the end of their technical and economic lives. An increased risk of failure could cause safety and reliability issues	Implement a program of unit protection relay and control system replacement projects at various substations	Various	25–35	Replace assets on failure
2019–2023	Many items of online condition monitoring equipment will be near the end of their usable lives in the 2019-2023 period (12-20 years old) and are exhibiting high failure rates	Replace obsolete online asset condition monitoring equipment	Various	4-8	Continue corrective maintenance program only
2024–2028	Transmission line support systems (towers, poles) components at end-of-life, leading to a high failure rate, and safety and network availability risk	Implement a program of transmission line support system refurbishment to renew line asset components and extend line life	Various	10–15	Replace individual components or sections on failure or Full line replacement
2024–2028	Transmission line insulator systems at end-of-life, leading to a high failure rate, safety and network availability risk, and fire start risk	Implement a program of transmission line insulator system refurbishment to renew line asset components and extend line life	Various	50–80	Replace individual components or sections on failure or Full line replacement
2024–2028	Transmission line conductor and earthwire components at end-of-life, leading to a high failure rate, safety and network availability risk, and fire start risk	Implement a program of transmission line conductor and earthwire refurbishment to renew line asset components and extend line life	Mid North / Riverland	70–100	Replace individual corroded conductor sections or Full line replacement
2024–2028	Substation assets have been identified with high failure rates and, safety risks or have been assessed to be at the end of their technical and economic lives	Implement a program of unit asset and infrastructure replacement projects at various substations	Various	50–80	Replace assets on failure

Project timing	Limitation	Recommended solution	Region	$ million	Alternative option(s)
2024–2028	Various individual substation protection and control systems have been assessed to be at the end of their technical and economic lives. An increased risk of failure could cause safety and reliability issues	Implement a program of unit protection relay and control system replacement projects at various substations	Various	30–50	Replace assets on failure

G4 Summary of contingent projects

Table G-4: Contingent projects

Project	Proposed trigger[55]	Reference	$ million
Eyre Peninsula major upgrade Options currently being considered are described in the Eyre Peninsula Electricity Supply Options PSCR, published in April 2017	Successful completion of the RIT-T including an assessment of credible options identifying the duplication or replacement of the existing Cultana-Yadnarie and/or Yadnarie-Port Lincoln transmission lines as the preferred option	Section 8.4.1	200[56]
Insufficient system strength Install synchronous condensers specifically designed to contribute strongly to fault currents at a central location or locations	• Confirmation by AEMO of the existence of a Network Support and Control Ancillary Services (NSCAS) gap relating to system strength, or other requirement for ElectraNet to address a system strength requirement, in the South Australian region. • Successful completion of the RIT-T (or equivalent economic evaluation) including an assessment of credible options showing a transmission investment is justified.	Section 8.3.3	40-70
South Australian Energy Transformation Options currently being considered are described in the South Australian Energy Transformation PSCR, published in November 2016	Successful completion of the RIT-T for the South Australian Energy Transformation with the identification of a preferred option or options: • demonstrating positive net market benefits and/or • addressing a reliability corrective action.	Section 8.3.2	200-500[57]
Upper North region eastern 132 kV line upgrade Rebuild the Davenport to Leigh Creek 132 kV line	• Customer commitment for additional load to connect to the transmission network causing the Davenport to Leigh Creek 132kV line to exceed its thermal limit of 10 MVA. • Successful completion of the RIT-T including an assessment of credible options showing a new connection point and line upgrade is justified.	Section 8.6.1	60

55 In addition, the following two trigger conditions are proposed to apply to each of the projects listed:
- Determination (if applicable) by the AER under clause 5.16.6 of the Rules that the proposed investment satisfies the RIT-T
- ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

56 The differential cost over the alternative partial replacement option listed in Table G-1 at about $80 million would be around $120 million, for which funding would be sought should the contingent project be triggered.

57 This represents an estimate of the South Australian portion of the cost of a new interconnector.

Project	Proposed trigger[55]	Reference	$ million
Upper North region western 132 kV line upgrade Uprate or rebuild the Davenport to Pimba 132 kV line	• Customer commitment for additional load to connect to the transmission network causing the Davenport to Pimba 132kV line to exceed its thermal limit of 76 MVA. • Successful completion of the RIT-T including an assessment of credible options showing a transmission investment is justified.	Section 8.6.2	110

Abbreviations

AC	Alternating current
ADE	Adelaide zone as outlined in the NTNDP.
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMD	Agreed maximum demand
ARENA	Australian Renewable Energy Agency
CBD	Central business district
DNSP	Distribution network service provider
ESCOSA	Essential Services Commission of South Australia
ESCRI-SA	Energy Storage for Commercial Renewable Integration – South Australia
ESD	Energy storage device
ESOO	Electricity statement of opportunities, published by AEMO
ETC	Electricity Transmission Code (South Australia)
FCAS	Frequency control ancillary service
HVAC	High voltage alternating current
HVDC	High voltage direct current
km	Kilometres
kV	Kilovolts
MVA	Megavolt-ampere (a unit of apparent power)
Mvar	Megavolt-ampere reactive (a unit of reactive power)
MW	Megawatt (a unit of active power)
NCIPAP	Network Capability Incentive Parameter Action Plan
NEFR	National Electricity Forecast Report, published by AEMO
NEM	National Electricity Market
NNOR	Non Network Options Report (part of the RIT-D)
NPV	Net present value
NSA	Northern South Australia zone as identified in the NTNDP
NSCAS	Network support and control ancillary service
NTNDP	National Transmission Network Development Plan.
PACR	Project Assessment Conclusions Report (part of the RIT-T)
PADR	Project Assessment Draft Report (part of the RIT-T)
POE	Probability of exceedance
PSCR	Project Specification Consultation Report (part of the RIT-T)
PV	Photovoltaic
RET	Renewable energy target
RIT-D	Regulatory investment test for distribution

AC	Alternating current
RIT-T	Regulatory investment test for transmission
RoCoF	Rate of change of frequency
Rules	National Electricity Rules
SESA	South East South Australia region as identified in the NTNDP
SVC	Static Var compensator
TNSP	Transmission Network Service Provider
UFLS	Under-frequency Load Shedding. The primary control measure used to maintain viable frequency operation following a system separation event.
Var	Volt-ampere reactive (a unit of reactive power: one million Var equal one Mvar)

Glossary of Terms

Term	Description
10% POE	10% probability of exceedance. This is used to indicate a value that is expected to be exceeded once in every 10 years
90% POE	90% probability of exceedance. This is used to indicate a value that is expected to be exceeded nine times in every 10 years
Base scenario	A planning scenario developed and evaluated as part of ElectraNet's planning process. This scenario informs ElectraNet's business plan. See also SA Mining Growth scenario and SA Renewable Generation Expansion scenario
Constraint	A limitation on the capability of a network, load or a generating unit that prevents it from either transferring, consuming or generating the level of electrical power which would otherwise be available if the limitation was removed
Dynamic rating	A thermal rating for equipment that is variable, based on prevailing conditions such as: ambient temperature, actual plant loading, wind speed and direction, solar irradiation, and thermal mass of plant
Eastern Hills Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
Eyre Peninsula Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
Frequency control ancillary service (FCAS)	Contingency FCAS helps to stabilise system frequency from the first few seconds after a separation event, while regulation FCAS raise and lower services help AEMO control system frequency over the longer term
Jurisdictional Planning Body	ElectraNet is the Jurisdictional Planning Body for South Australia under clause 11.28.2 of the Rules. This means that ElectraNet has specific obligations with regard to network connection, network planning and establishing or modifying a connection point
Main Grid	ElectraNet's Main Grid is a meshed 275 kV network that is connected to two interconnectors and seven regional networks in South Australia
Maximum demand	The highest amount of electricity drawn from the network within a given time period
Metropolitan Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
Mid North Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
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
National Electricity Rules (Rules)	The Rules prescribe the obligations of national electricity market participants, including a TNSP's obligations regarding network connection, network planning, network pricing and establishing or making modifications to connection points
Net present value (NPV)	Net present value, usually expressed as cost per megawatt, is used to help assess the economic feasibility of network and non-network solutions to network limitations

Term	Description
Nominal voltage levels	The design voltage level, nominated for a particular location on the power system, such that power lines and circuits that are electrically connected other than through transformers have the same nominal voltage. In ElectraNet's transmission system the nominal voltage level is typically 275 kV, 132 kV, or 66 kV
Non-network options	Non-network options, generally refers to options which address a network that don't include network infrastructure, such as generation, market network services and demand-side management initiatives
Over voltage	A system condition in which actual voltage levels at one or more locations exceeds 110% of the nominal voltage
Over-frequency generator shedding (OFGS)	A control scheme that coordinates tripping of generators when the system frequency increases due to supply exceeding demand
Peaking power plant	A power plant that only generally runs during periods of very high wholesale electricity prices, which typically correlate with times of very high electricity demand
Reactive power margin	The reactive power margin at a given location is the amount of additional reactive power that could be drawn that location without initiating voltage collapse
Registered participants	As defined in the Rules
Riverland Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
Rules	The National Electricity Rules which prescribe the obligations of national electricity market participants, including a TNSP's obligations regarding network connection, network planning, network pricing and establishing or making modifications to connection points
SA Mining Growth scenario	A planning scenario developed and evaluated as part of ElectraNet's planning process. This scenario considers a number of potential mining loads, incorporating general information from connection enquiries that is generalised for long-term planning
SA Renewable Generation Expansion scenario	A planning scenario developed and evaluated as part of ElectraNet's planning process. This scenario represents an extreme yet possible expansion of SA wind generation
South East Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
Thermal ratings	The maximum amount of electrical power that a piece of equipment can accommodate without overheating
Transfer limit	The maximum permitted power transfer through a transmission or distribution network
Under frequency load shedding (UFLS)	The primary control measure used to maintain viable frequency operation following a system separation event
Upper North Region	One of ElectraNet's seven regional networks in South Australia. See Appendix B for details
Voltage collapse	An uncontrolled decay in voltage due to reactive power losses and loads exceeding reactive power sources, culminating in a sudden and precipitous collapse of voltage. Voltage collapse is associated with cascading network outages due to the mal-operation of protection equipment at low voltage levels, leading to widespread load loss