SOUTH AUSTRALIAN TRANSMISSION ANNUAL PLANNING REPORT

June 2016

ElectraNet

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Executive Summary

The energy industry is changing at an increasing pace. Customers now use, produce and value electricity services in different ways and are transforming electricity systems worldwide. Nowhere is this more evident than in South Australia, where intermittent renewable energy penetration rates are the highest in the country and amongst the highest in the world. Strongly supportive Federal and State government policies are expected to continue to drive further significant increases in renewable energy generation in South Australia.

South Australia's transmission network needs to evolve to meet these changing needs. ElectraNet is continually looking ahead to identify any obstacles or opportunities and put plans in place to accommodate them, as part of our annual planning process.

This South Australian Transmission Annual Planning Report provides a summary of 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 what ElectraNet is doing to help address the emerging challenges of integrating higher levels of intermittent renewable energy into the power system. This includes investigating the technical and economic feasibility of a new transmission interconnector between South Australia and New South Wales or Victoria, and the role of grid connected energy storage to provide system security services to support higher levels of intermittent renewable energy.

New challenges that are emerging include reducing system strength (minimum fault currents) and declining minimum demand. Minimum fault currents are reduced when less conventional generators are operating. ElectraNet is investigating whether lower fault currents will adversely impact customers or the operation of the network, and is exploring potential ways to address any adverse impact. The continued growth in solar PV connections is contributing to declining minimum demand in South Australia. This increases the challenge of managing high system voltages under these conditions and is expected to require additional reactive plant to be installed over the planning period.

Looking ahead, our network planning is based on three main scenarios for South Australia's future: Base; SA Mining Growth; and SA Renewable Generation Expansion. The report identifies emerging limitations for these scenarios and their potential solutions (summarised in Table 1).

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

This report is also part of a suite of documents, including the *Network Vision Discussion Paper,* the *Network Capability Incentive Parameter Action Plan* for 2015–2018 and the *2016 South Australian Connection Point Forecasts* report, that address the future of the network.[1] As South Australia's Transmission Network Service Provider, the presentation of this report also satisfies our reporting requirements under the National Electricity Rules (Appendix B).

[1] Each of these documents is available on electranet.com.au.

Table 1: High level summary of planning scenario outcomes

Scenario	Description	Network reinforcement required (10-year planning outcomes)
Base	ElectraNet's central planning scenario	Dynamic 275 kV reactive support at Davenport following the closure of Northern Power Station Potential market benefits could be released with additional interconnector capacity
SA Mining Growth	Considers a number of potential mining loads, incorporating general information from connection enquiries that is generalised for long-term planning	Dynamic 275 kV reactive support at Davenport following the closure of Northern Power Station. Significant network reinforcement in specific parts of the network, depending on actual mining developments driving this investment Potential market benefits could be released with additional interconnector capacity
SA Renewable Generation Expansion	Represents a further possible expansion of SA wind generation, above that already included in the base scenario. It is based on connection enquiries, which have been generalised for long-term planning	Dynamic 275 kV reactive support at Davenport following the closure of Northern Power Station. Moderate network reinforcement to avoid significant network congestion at maximum demand times At low demand times, wind generation output may be limited by the ability to export power from South Australia Potential market benefits could be released with additional interconnector capacity

We invite you to provide feedback on any aspects of this report, from our demand projections and emerging network limitations to proposed solutions, the scope of our planning scenarios 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 is a specialist 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 the economy.

Our business includes South Australia's regulated transmission network. ElectraNet plans, builds, operates, maintains and owns South Australia'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 that transports power generated from local and interstate sources to metropolitan and regional areas of demand (load centres).

Our network safely transports electricity over long distances to metropolitan, regional and remote areas. It is made up of over 5,600 circuit kilometres of transmission lines and cables that operate at voltages of 275 kV, 132 kV and 66 kV, as well as 90 high-voltage substations with modern centralised monitoring, control and switching facilities.

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 on the cost and reliability of electricity for customers that are connected to SA Power Networks' distribution network.

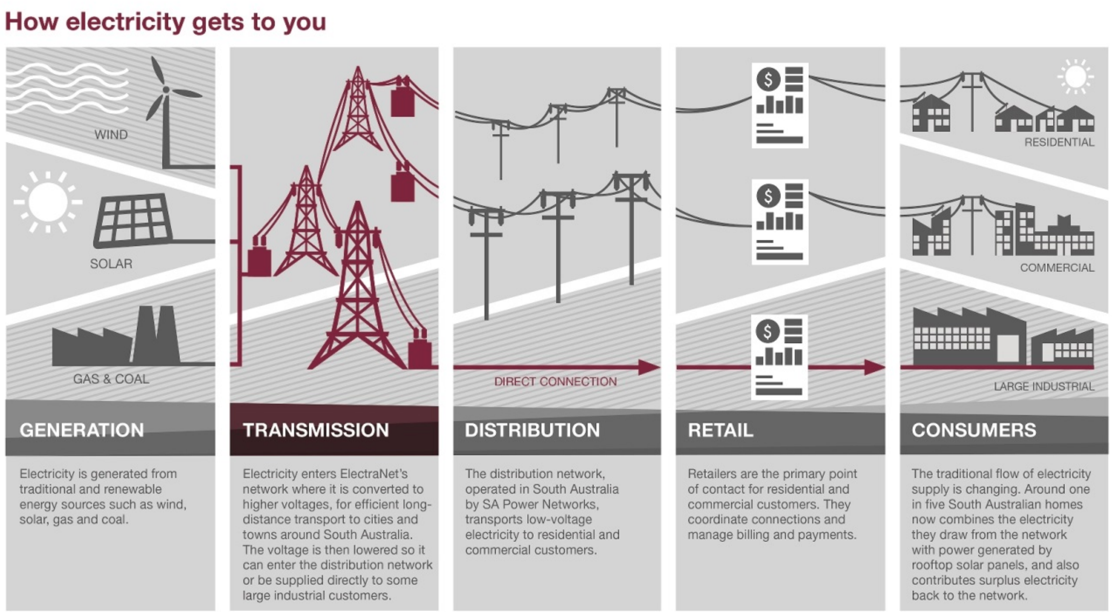

Figure 1-1: ElectraNet's role in supplying electricity

1.2 Network planning approach and reporting

Each year, ElectraNet reviews the capability of its transmission network and regulated connection points to meet ongoing demand for electricity, 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 (Figure 1-2) fit with the various regulatory arrangements and environments (Appendix A) that impact the annual planning outcomes.

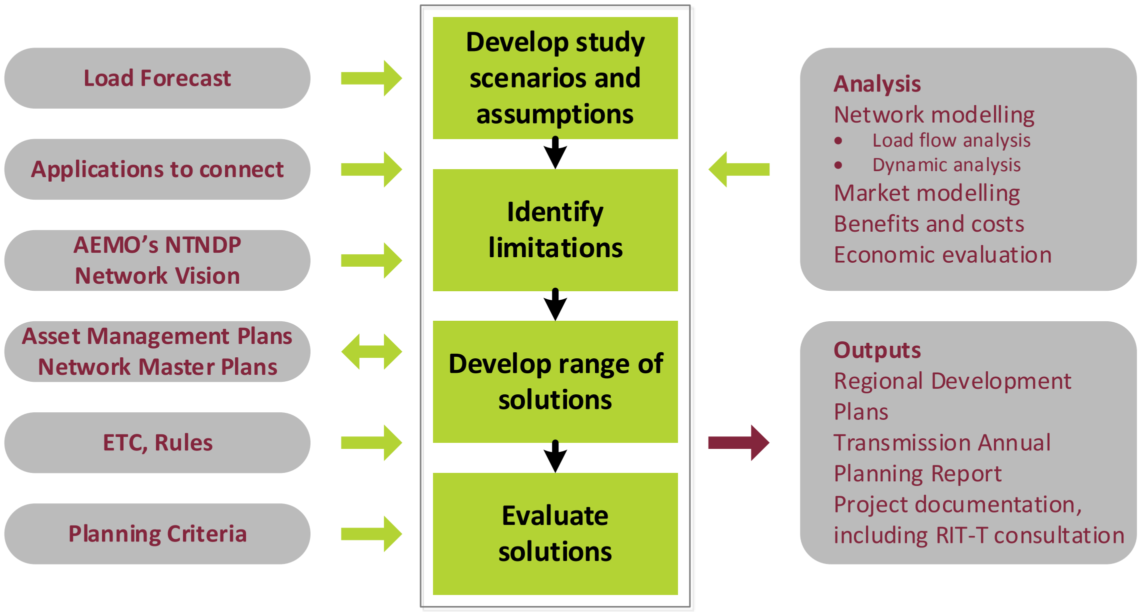

Figure 1-2: ElectraNet's approach to network planning

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 the next 10-year planning period (1 July 2016 to 30 June 2026) and identifies potential network capability limitations and possible solutions.

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 forecasted 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).

This report does not define a single specific future development plan for the South Australian transmission system, but rather is intended to form part of a consultation process to make sure that 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 How does this report differ from the 2015 Transmission Annual Planning Report?

We are committed to continuous improvement of the Transmission Annual Planning Report and its value to our customers and industry stakeholders. Key changes in 2016 include:

- a stronger focus on the emerging challenge of integrating further intermittent renewable energy into the South Australian network (chapter 3)
- new information has been added on planning for significant investments to replace or refurbish assets (Section 7.3)
- streamlining the report to improve readability, including moving reference information to appendices – for example, the detailed summary tables of projects can now be found in Appendix G

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

1.4 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 such that 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). 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. We also participate in inter-regional system tests associated with new or augmented interconnections.

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)
- 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 forecast and generator behaviour as well as changes in government policies.

2. The South Australian transmission system

2.1 Overview

The South Australian transmission system connects the major load centres with the 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.

ElectraNet's Main Grid (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.

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 790 MW.[2] The combined maximum transfer capability for export from South Australia to Victoria under existing system normal operating conditions is 650 MW.[3] The combined limit will be further increased once the Black Range series capacitors enter into service in mid-2016, as part of the Heywood interconnector upgrade (section 7.1.2.1).

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 limitations. Actual transfer also depends on the market dispatch of scheduled generation, and the operation of non-scheduled generation.

2 Consisting of 570 MW import through Heywood interconnector and 220 MW import through Murraylink interconnector.

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

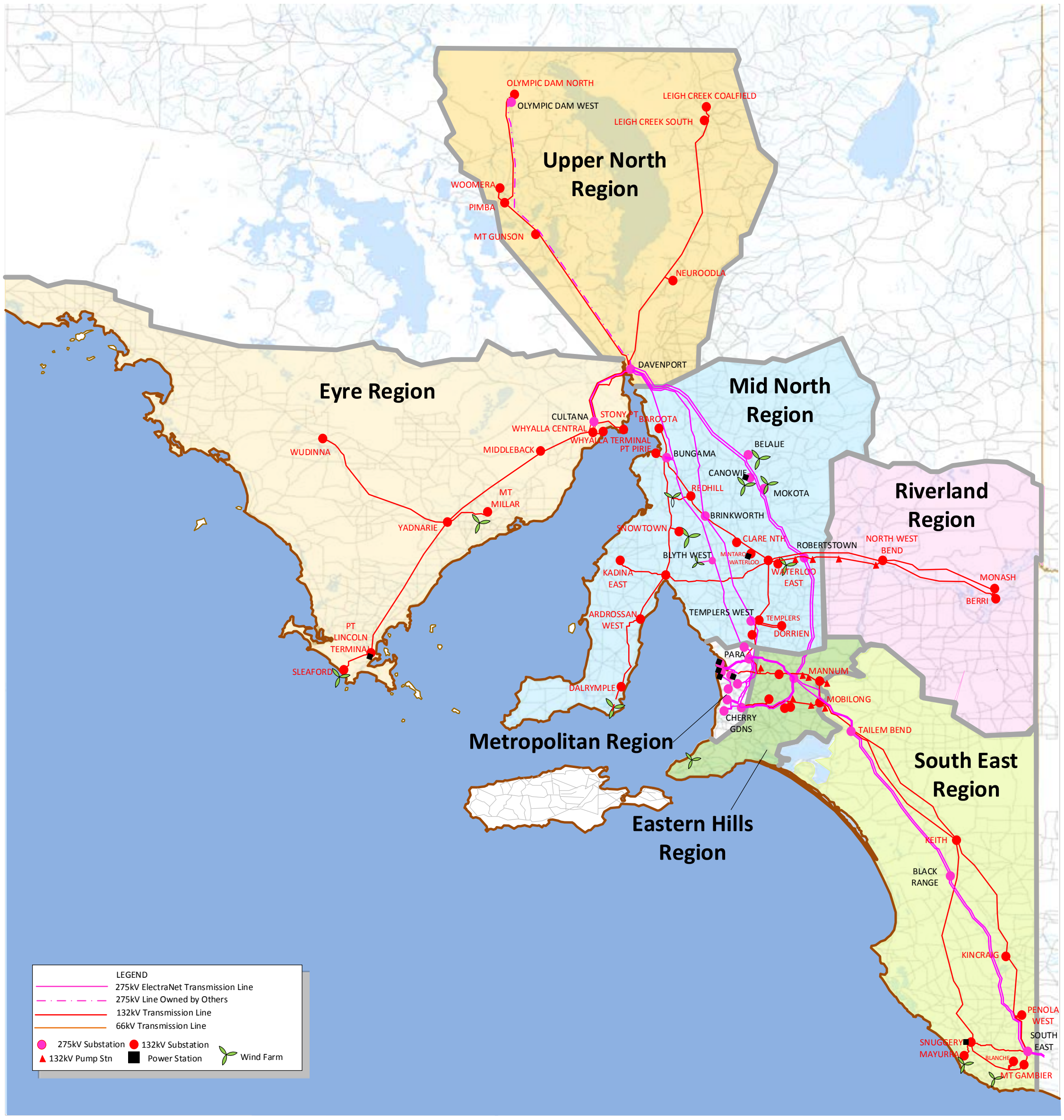

Figure 2-1: **South Australia's transmission system**

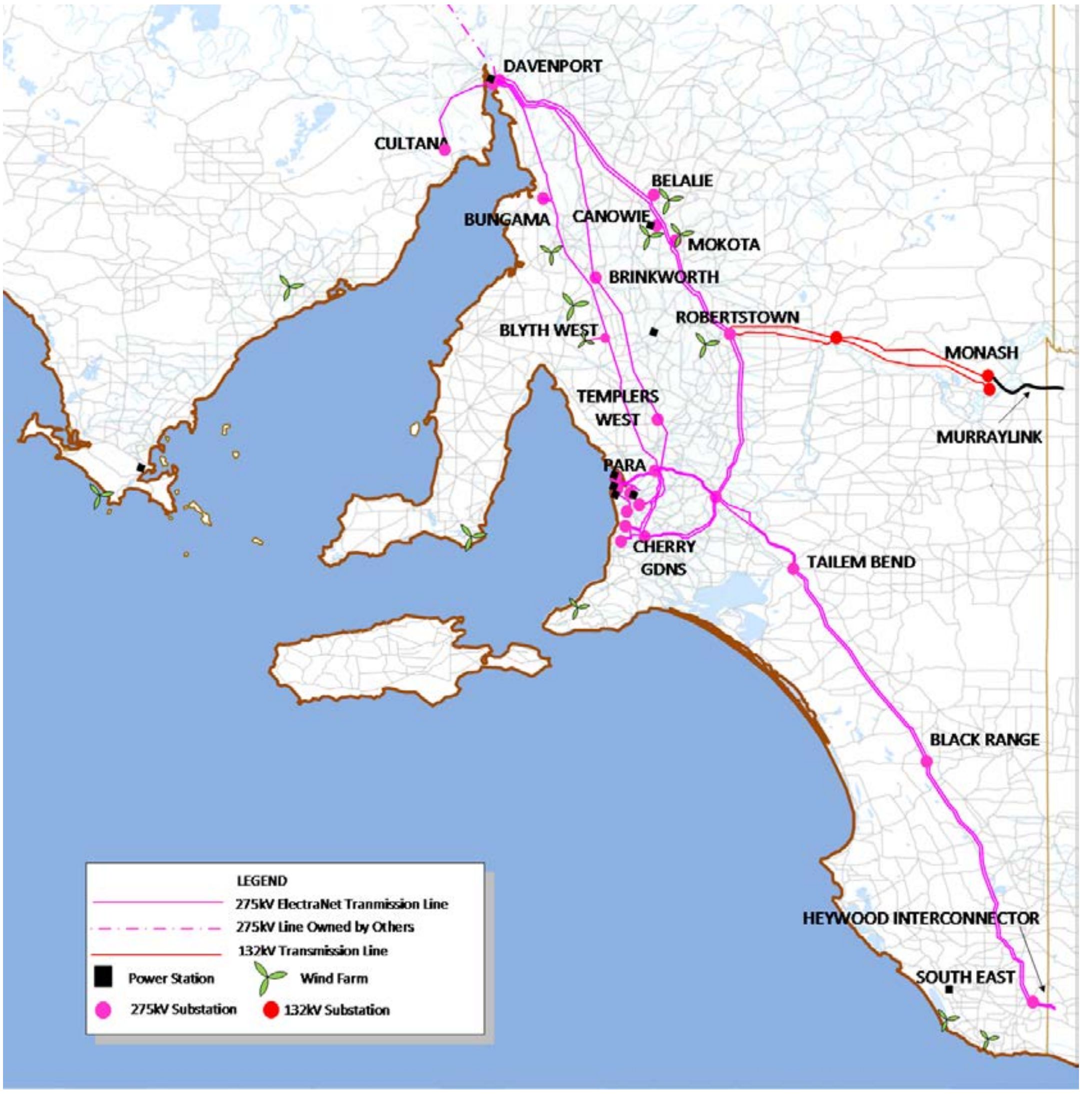

Figure 2-2: ElectraNet's Main Grid

2.2 Renewable energy generation

An increasing number of renewable energy generators have connected to the transmission network since 2000 when government policy began responding to climate change. About 1500 MW of wind generation has been installed to date, and wind supplied about 33% of the State's energy in 2014–15.[4] There is continued interest in wind generation as South Australia still has high quality wind resources available, as shown by the connection of Hornsdale wind farm in 2016. Interconnectors were increasingly used to export power out of South Australia as wind generation increased.

However, importing power has again become more common in the last few years, due to increasing gas prices and the availability of lower cost generation from elsewhere in the national electricity market – even during lower demand periods with good levels of wind generation. Significant wind generation coupled with low system demand can also result in low levels of conventional generating units connected to the system. The implications of this changing generation mix are explored in Chapter 3.

[4] South Australian Wind Study Report, AEMO, p. 21. Published October 2015. Available at http://www.aemo.com.au/Electricity/Planning/South-Australian-Advisory-Functions/South-Australian-Wind-Study-Report

Wind is an intermittent energy source that cannot 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 will be at least 9.9% of installed capacity in South Australia during high demand periods over summer.[5]

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 may indicate an overall declining trend (Figure 2-3).

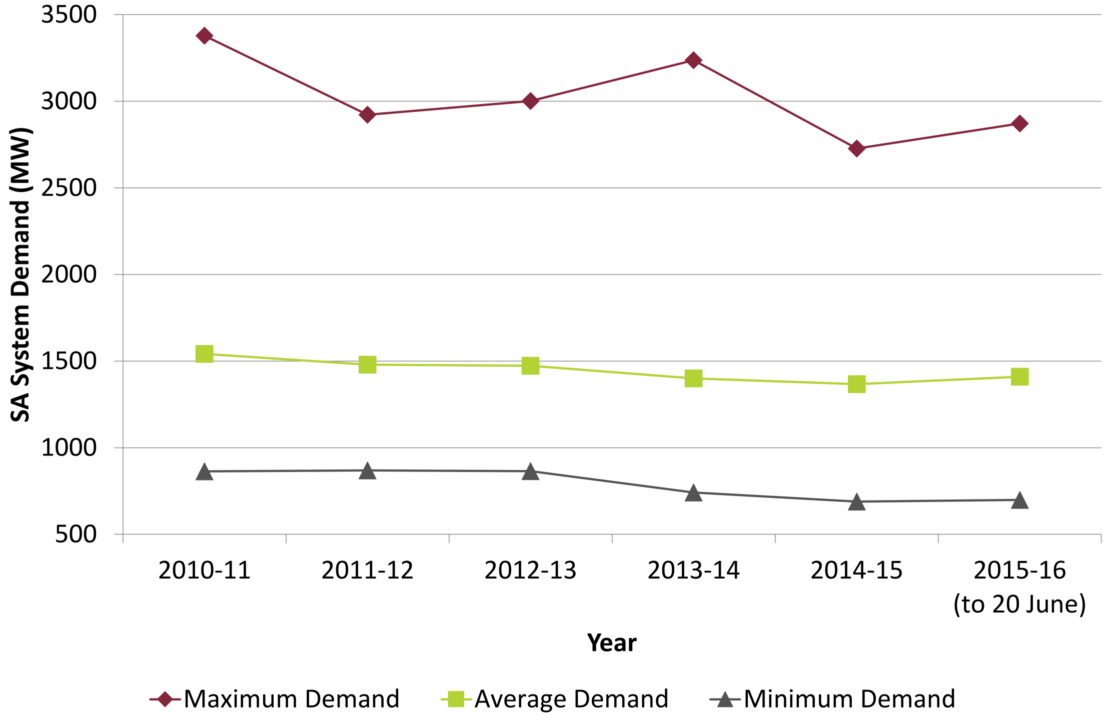

Figure 2-3: Maximum, average, and minimum electricity demands on ElectraNet's network

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, 1000–2000 MW demand is more 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.

5 South Australian Wind Study Report, AEMO, p. 15. Published October 2015. Available at http://www.aemo.com.au/Electricity/Planning/South-Australian-Advisory-Functions/South-Australian-Wind-Study-Report

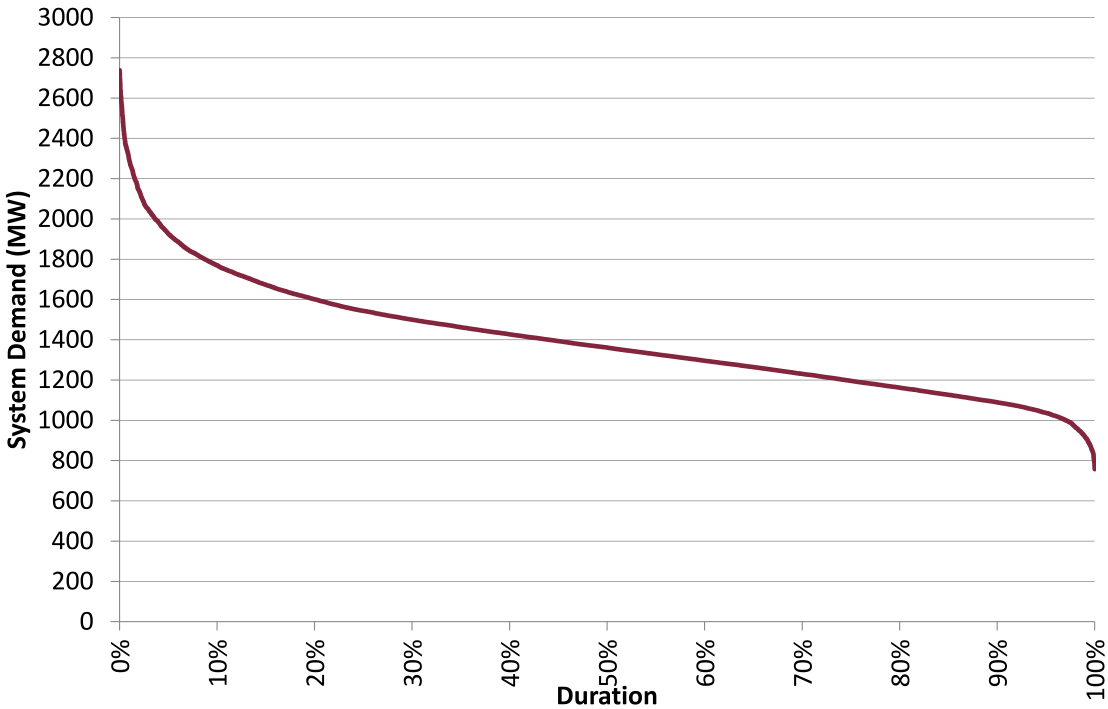

Figure 2-4: South Australian system wide load duration curve for 2015-16 (to 20 June 2016)

Note the very small percentage of time that relatively high demands (above 2,500 MW) are present on the South Australian transmission network.

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

2.4 Interconnector transfer capability

The interconnector transfer capability will change once the upgrade to the Heywood interconnector is complete (mid 2016). The combined maximum transfer capability between South Australia and Victoria under system normal operating conditions will increase to about 870 MW across the Heywood and Murraylink interconnectors, but could be higher or lower depending on conditions at the time. Interconnected network tests will 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.

2.5 Northern Power Station closure

Alinta Energy announced in June 2015 that the Northern Power Station would not operate beyond March 2018.[6] Northern Power Station subsequently ceased electricity generation on 9 May 2016.[7] The impacts of this closure are discussed further in section 3.2.1.

[6] Alinta Energy news announcement on 11 June 2015, available at: https://alintaenergy.com.au/about-us/news/flinders-operations-announcement

[7] Alinta Energy news announcement on 9 May 2016, available at: https://alintaenergy.com.au/about-us/news/augusta-power-station-ceases-generation.

3. An emerging challenge – integration of renewable energy

The energy industry is changing at an increasing pace. Customers now use, produce and value electricity services in different ways and are transforming electricity systems worldwide. Nowhere is this more evident than in South Australia where intermittent renewable energy penetration rates are the highest in the country and amongst the highest in the world.

The transmission network continues to evolve to meet customers' changing needs and reflect new technology and supply options available at both the large and small scale (e.g. rooftop solar PV installations combined with battery storage).

Customers who adopt new energy technologies in their homes or businesses continue to receive additional benefits from being connected to the network (Figure 3-1) and a cheaper overall solution than relying on a stand-alone power system.

ElectraNet continues to plan and prepare the network to accommodate the changing ways that electricity will be generated and consumed in the future.

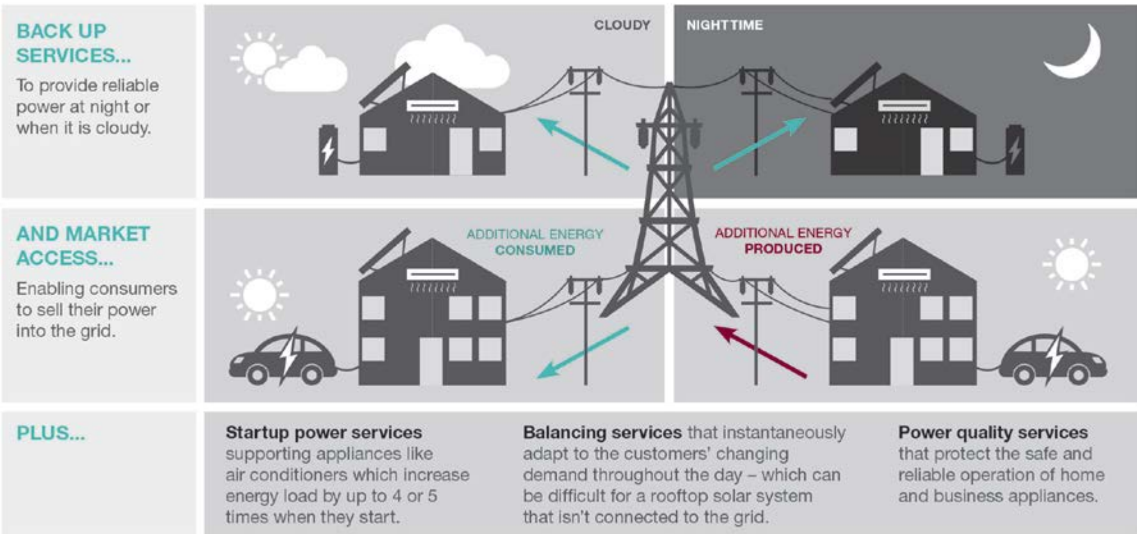

Figure 3-1: The value of the grid

The grid offers power back up services; market access for customers to sell power; and many other services to customers who have alternate technology installed in their home.

3.1 South Australian context

In recent years, renewable energy generation has also increased as a proportion of the total generation mix across the NEM. However, South Australia has by far the highest intermittent renewable energy penetration of any NEM region and has world-leading penetration levels of renewable generation compared to demand. This has been driven by the quality of solar and wind resources available as well as supportive state government policies. As the penetration of intermittent renewable generation has increased in South Australia, the contribution from conventional generators has reduced (Figure 3-2 and Figure 3-3).[8]

[8] Source: AEMO's *South Australian Historical Market Information Report*, July 2015, page 9, available at http://www.aemo.com.au/Electricity/Planning/South-Australian-Advisory-Functions/South-Australian-Historical-Market-Information-Report

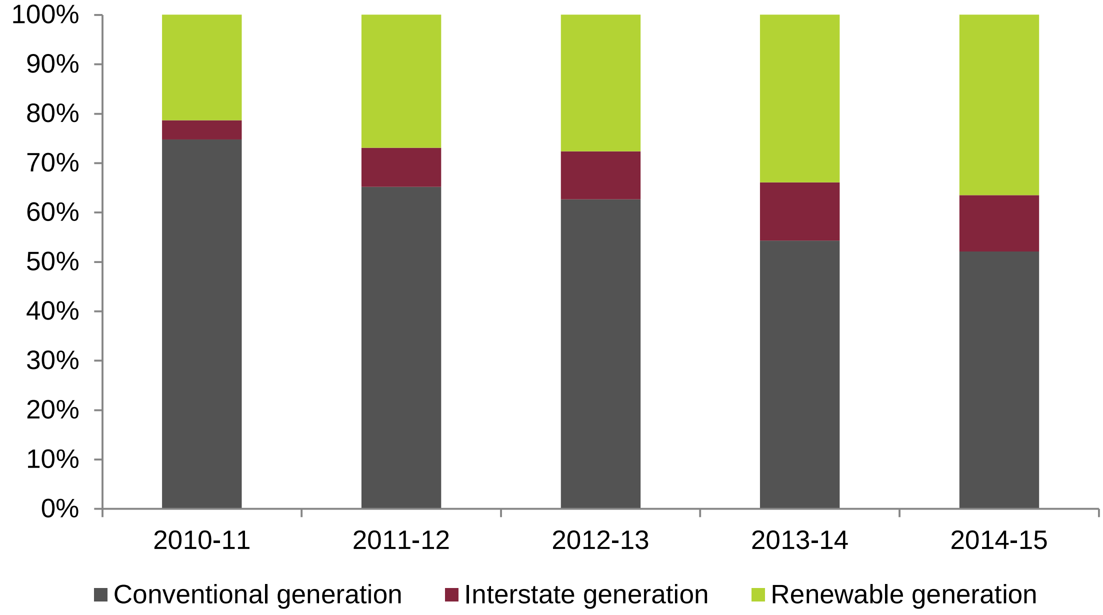

Figure 3-2: Energy generation patterns have changed significantly over the last five years

Source: AEMO's 2015 South Australian Historical Market Information Report

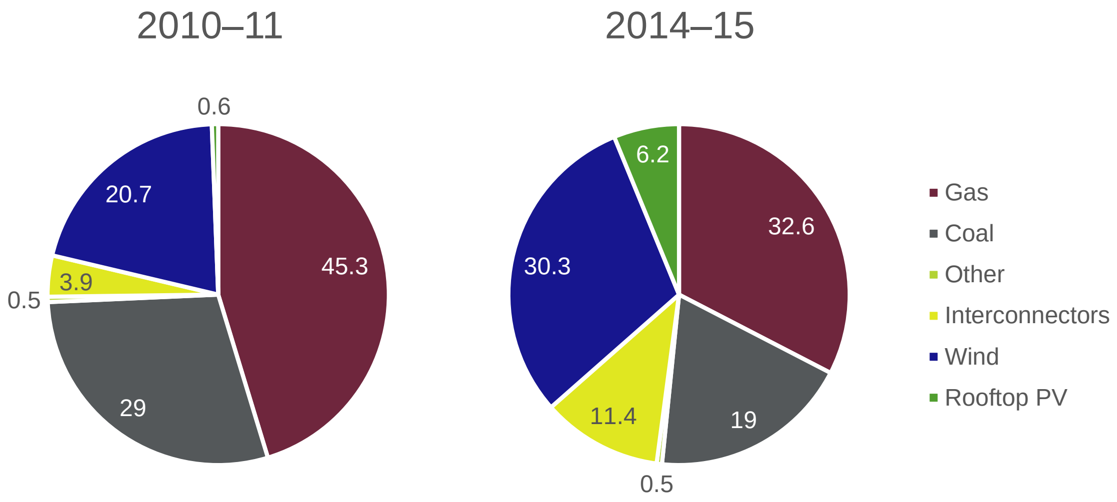

Figure 3-3: Renewable energy from wind and solar roof photovoltaic systems has increased significantly over the last five years

Source: AEMO's 2015 South Australian Historical Market Information Report

South Australian government policy continues to have a strong focus on unlocking the full potential of South Australia's renewable energy resources. Policy targets include:

- achieving 50% renewable energy production by 2025
- enabling investment of $10 billion in low carbon generation by 2025
- establishing Adelaide as the world's first carbon neutral city.[9]

[9] RenewablesSA, *A Low Carbon Investment Plan for South Australia*, available at http://www.renewablessa.sa.gov.au/files/93815-dsd-low-carbon-investment-plan-for-sa-final-web-copy.pdf.

Federal government policy is also expected to influence future renewable energy penetration through:

- a national renewable energy target (RET) of 33,000 GWh of large scale renewable energy generation by 2020 (announced May 2015).
- an economy-wide emissions reduction target of 26-28% of 2005 levels by 2030 (announced August 2015). The policy design required to meet the 2030 target will be settled in 2017-18.[10]
- signing of a voluntary agreement with 196 nations (Paris agreement) agreeing to 'holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels'.[11]

ElectraNet expects that these and future policies will continue to influence renewable energy development and in particular drive ongoing investment in large scale wind and solar energy generation.

We anticipate that the combination of these strongly supportive State and Federal government policies will enable South Australia to continue to attract a significant proportion of the NEM's renewable energy investment due to the high quality of wind and solar resources available in the State, especially if a new interconnector can unlock the opportunity for more renewable energy to be exported to New South Wales or Victoria.

3.2 How will rising renewable energy generation impact on the transmission system?

AEMO and ElectraNet have been working together to study the potential impact of high levels of renewable energy generation and low levels of conventional synchronous generation. In February 2016, AEMO and ElectraNet issued a joint technical report[12] on the work undertaken to identify limits to the secure operation of the South Australian system. Overall, the studies highlighted the increasing importance of the Heywood interconnector as a source of frequency control and system strength to support the secure and reliable operation of the South Australian power system.

In the longer term, the need for changes to market arrangements or infrastructure may increase to meet security and reliability expectations, particularly at times when South Australia is islanded (separated) from the remainder of the NEM.

Key challenges include:

- Ensuring voltage control in the north of South Australia continues to be adequate following the closure of Northern Power Station
- Ensuring satisfactory South Australian frequency control following an islanding event
- Investigating the potential benefit of additional interconnector capacity

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10 https://www.dpmc.gov.au/sites/default/files/publications/Summary%20Report%20Australias%202030%20Emission%20Reduction%20Target.pdf

11 United Nations Framework Convention on Climate Change, *Adoption of the Paris Agreement*, page 2, December 2015, available at https://unfccc.int/resource/docs/2015/cop21/eng/l09.pdf

12 AEMO and ElectraNet, *Update to Renewable Energy Integration in South Australia*, February 2016, available at http://www.aemo.com.au/Electricity/Market-Operations/Power-system-security

- Determining how best to use battery storage to meet system needs

Ensuring electricity supply continues to be safe, reliable, and of high quality. ElectraNet's work program over the next six to twelve months builds on the work described in the joint report and is described briefly in the sections that follow.

3.2.1 Voltage control in the north of South Australia

The Northern Power Station (NPS) performed an important transmission network voltage control service at the Davenport 275 kV substation in the Upper North region of South Australia, until it ceased electricity generation on 9 May 2016.[13]

ElectraNet analysis shows that the withdrawal of NPS will create challenges for transmission network voltage control in the Upper North and Eyre Peninsula regions during certain system operating conditions. ElectraNet has performed system studies to identify potential network adequacy and security limitations resulting from the withdrawal of NPS. These studies, and a review of past operational experience, have revealed the following limitations under certain credible demand and generation scenarios:

- Reactive power margin – reactive power reserve margins may not be met at the Davenport 275 kV connection point at times of high demand drawn from the Davenport to Olympic Dam 275 kV line; moderate to high system demand; and low wind generation in the Mid North region.
- Voltage collapse – for N-1-1[14] conditions the system would be at risk of voltage collapse under certain operating conditions.
- Over-voltage – the Davenport 275 kV connection point voltage is often operating above 105% of its nominal voltage to mitigate against the risk of voltage collapse in the network supplied by the Davenport to Olympic Dam 275 kV line. Operating above 105% is expected to result in over-voltage at times of low wind generation in Mid North following an unplanned outage of the Davenport to Olympic Dam 275 kV line.

ElectraNet considers that improved voltage control in the northern regions of South Australia is needed and intends to initiate a Regulatory Investment Test for Transmission (RIT-T) to procure the most economic network or non-network solution that resolves the issue. There is interest from proponents in developing large-scale solar thermal generation at Port Augusta.[15] ElectraNet will consider all the latest available information in conducting the RIT-T process.

3.2.2 Frequency control following separation of South Australia from the NEM

The separation of South Australia from the NEM constitutes a significant event that requires post-contingency control systems to ensure that the islanded South Australian network continues to operate and is secure.

Under-frequency load shedding (UFLS) is the primary control measure used to maintain viable frequency operation following a system separation event. AEMO is responsible for

[13] Alinta Energy news announcement on 9 May 2016, available at: https://alintaenergy.com.au/about-us/news/augusta-power-station-ceases-generation
[14] An N-1-1 condition is a measure of system security, and means that the system is able to withstand the consecutive loss of any two components of the power system.
[15] http://reneweconomy.com.au/2016/hewson-backed-company-plans-170mw-solar-thermal-baseload-power-plant-for-port-augusta-76729.

liaising with network service providers to ensure that the South Australian UFLS scheme is able to successfully contribute to frequency recovery following a separation event.

ElectraNet has recently analysed the existing South Australian UFLS scheme. A key finding is that at times of high rooftop solar PV generation, the reduced nett demand covered by the UFLS scheme may reduce its ability to restore frequency stability after a separation event. This will increasingly be the case as the amount of generation from rooftop solar PV exceeds the local demand at more and more locations.

The potential impact of a system separation event will increase following the increase in available interstate transfer capacity that will be delivered by the Heywood interconnector upgrade from mid-2016. The effectiveness of the South Australian UFLS scheme may be able to be increased by:

- extending its coverage to loads that are not currently participating in the UFLS scheme
- incorporating relays sensitive to rate of change of frequency (RoCoF) in the UFLS design
- upgrading equipment to enable UFLS to be selectively disarmed in locations where the local generation exceeds the local demand.

ElectraNet is assisting AEMO and SA Power Networks to review and implement a range of short and long term measures to ensure that the South Australian UFLS will continue to be able to restore frequency stability after a separation event.

We are also working with AEMO and other stakeholders on the design and implementation of an Over Frequency Generation Shedding scheme for South Australia. This scheme would maintain frequency stability in South Australia in a controlled way following an unplanned islanding event at times when surplus generation was being exported prior to the separation event.

Murraylink opportunities

ElectraNet is engaging with APA (operator of the Murraylink interconnector); AusNet Services; and AEMO, in its capacity as the Victorian transmission network planner, to consider the technical feasibility, cost, and potential benefits of implementing frequency control through the Murraylink interconnector. This could:

- help to limit the RoCoF immediately following a separation event (too high a RoCoF could cause generators to trip off, which would further increase the frequency instability)
- provide contingency frequency control ancillary services (FCAS), which help the system frequency to stabilise in the first few seconds after a system separation event
- provide regulation FCAS raise and lower services, which enable AEMO to provide long-term control of the system frequency

The initial focus is on finding a way for Murraylink to provide regulation FCAS for South Australia. This could be achieved at relatively low cost by using existing facilities, with only minor modifications.

3.2.3 Additional interconnector capacity

ElectraNet has undertaken a pre-feasibility assessment of the costs and likely benefits of increasing the level of interconnection between South Australia and the Eastern states that would also address system security concerns in South Australia. The outcome of this work shows the potential for new interconnectors to be economically feasible. The South Australian government is contributing $500,000 towards a detailed feasibility study.[16]

In the pre-feasibility assessment, ElectraNet assessed the likely benefits of an upgrade between Robertstown in South Australia and Darlington Point in New South Wales, with an estimated cost of about $500 million. The assessment indicated that such an interconnector would likely deliver sufficient market benefits to customers and producers of electricity, and warrants further investigation.

This will now be explored in more detail with TransGrid, the transmission network service provider for New South Wales, and AEMO. It will also be subject to extensive consultation with electricity consumers and industry stakeholders.

ElectraNet intends to commence a RIT-T consultation in September 2016. The RIT-T will consider a range of potential interconnector options to either New South Wales or Victoria, and also seek alternative solutions that might deliver similar market benefits.

Expected market benefits will include NEM wide fuel cost savings, capital investment savings and improved system security and reliability outcomes for customers in South Australia and the NEM. Any final investment decision will be subject to a rigorous regulatory process with oversight by the Australian Energy Regulator (AER).

A potential new interconnector would further build upon the benefits provided by ElectraNet's upgrade of the existing South Australia to Victoria (Heywood) interconnector.

3.2.4 Grid connected energy storage

ElectraNet has examined the business case for medium to large scale (5–30 MW) non-hydro energy storage systems to assist in intermittent renewable energy integration in South Australia, through the Energy Storage for Commercial Renewable Integration – South Australia (ESCRI-SA) project. This project has been partly funded by the Australian Renewable Energy Agency (ARENA) and was undertaken by a consortium consisting of AGL, ElectraNet and Worley Parsons.

ESCRI-SA Phase 1 was completed in December 2015 with the final report suggesting a potential Phase 2 delivery and testing project involving a 10 MW, 20 MWh Energy Storage Device (ESD) located on the Yorke Peninsula and providing a range of network and market services. However, the business case for such an asset was poor.[17]

The project was subsequently reconfigured as a 30 MW, 8 MWh battery to be installed at Dalrymple in South Australia and is being presented to ARENA for funding support.

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[16] Department of State Development, *State Budget 2016/17: Study into new interconnector*, 14 June 2016, available at http://www.statedevelopment.sa.gov.au/news-releases/all-news-updates/state-budget-2016-17-study-into-new-interconnector

[17] Available at: http://arena.gov.au/news/demystifying-utility-scale-battery-storage/

We are confident that utility scale energy storage can effectively address emerging system security concerns resulting from a high penetration of intermittent renewable generation and thereby be a key enabler of intermittent renewable energy on an interconnected power system

3.2.5 Reduced minimum fault currents (system strength)

System strength is related to fault current, which is the electrical current that flows when a fault occurs on the system – that is, when one or more electrical conductors contact the ground or each other. The contact could be direct or through a mediating material such as a tree branch. If allowed to continue, fault currents present a safety risk to people and equipment. Protective devices are installed throughout the system to mitigate any risk by quickly disconnecting any part of the system where a fault occurs.

These protective devices require a minimum fault current to detect fault conditions and operate as designed.

Conventional generators generally contribute more fault current than existing intermittent renewable technologies such as wind turbines and solar PV farms. This means that fault currents are expected to decrease as conventional generation is displaced from the system by intermittent renewables. This may introduce several challenges into the electricity system. ElectraNet is investigating the impacts of reduced system strength and considering whether:

- protective devices and power electronic devices on the transmission system and distribution network can continue to perform satisfactorily
- existing wind farms can continue to ride through disturbances without being disconnected
- reactive plant, such as reactors and capacitors, can continue to be switched without exceeding sudden voltage change limits.

Preliminary results indicate that existing wind farms will still be able to ride through disturbances without being affected, and reactive plant connected to the transmission network will still be able to be switched without exceeding sudden voltage change limits.

However, consideration of protective device adequacy indicates that there may be a significant number of transmission lines where protective devices will be unable to detect all faults at times of low fault current. ElectraNet is currently determining whether this could be fixed by replacing or upgrading the relevant protective devices. Alternatively, a more substantial investment, such as the installation of large synchronous condensers in strategic network locations, would help to maintain suitable levels of minimum fault currents.

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

Each year AEMO is required to publish a National Transmission Network Development Plan (NTNDP) in its role as the National Transmission Planner. The NTNDP considers both potential transmission and generation development, and aims to enable TNSPs to efficiently coordinate investment planning in the national electricity network.

The 2015 NTNDP:

- 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.[18]

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).

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.

[18] AEMO. *2015 National Transmission Network Development Plan*. Available at http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan.

4.1 Network limitations identified in the NTNDP

The 2015 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. The emerging reliability limitation that had been identified in the 2014 NTNDP on the 132 kV line between Robertstown and North West Bend in South Australia was addressed by ElectraNet during 2015 (section 7.1.1).

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.[19] The 2014 NTNDP had also identified five potential economic dispatch limitations in South Australia, of which four are common with the 2015 NTNDP limitations.

In the 2014 NTNDP, the existing constraints in the Lower South East to Heywood transmission corridor were identified and these are being addressed by the Heywood interconnector upgrade (section 7.1.2.1). The constraint E-S2 is newly identified in the 2015 NTNDP.

Table 4-1: Potential economic dispatch limitations identified in the 2015 NTNDP

NTNDP reference	NTNDP zone	Potential transmission limitations	Dispatch scenario	NTNDP scenario	2016 TAPR reference
E-S1	NSA	NSA–ADE 275 kV corridor	High wind/solar generation in the NSA zone	Gradual Evolution, Gradual Evolution Sensitivity	Table 4-4 and section 7.2.5.1
E-S2	NSA	Mid North 132 kV network	High wind/solar generation in the NSA zone	Gradual Evolution, Gradual Evolution Sensitivity, Rapid Transformation, Rapid Transformation Sensitivity	Table 4-4
E-S3	NSA	Riverland 132 kV network	High wind/solar generation in the NSA zone	Gradual Evolution, Gradual Evolution Sensitivity, Rapid Transformation, Rapid ransformation Sensitivity	Table 4-3 and section 3.2.2
E-S4	NSA	Eyre Peninsula 132 kV network	High wind/solar generation in the NSA zone	Gradual Evolution, Gradual Evolution Sensitivity, Rapid Transformation, Rapid Transformation Sensitivity	Section 7.2.4.1
E-S5	SESA	Tailem Bend–Tungkillo transmission corridor	New generation in SESA zone or high import from Victoria	Rapid Transformation, Rapid Transformation Sensitivity	Table 4-3 and Table 4-4

19 AEMO. *2015 National Transmission Network Development Plan*, page 21. Available at http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan.

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 assessed the top binding network constraints that impacted transmission network and interconnector flows during the 2015 calendar year (Table 4.2). Constraints selected for assessment were in, or were grouped with another constraint that was in, the top 10 by impact on marginal value or by binding duration in 2015.

In some cases, constraints which did not meet the criteria have been included for assessment when they were closely related to a constraint that did. Many of the constraints (Table 4-2) are managing limitations and contingencies outside of South Australia. Most of them 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 the frequency control ancillary services markets have not been included. Limitations identified in the 2015 NTNDP have been highlighted using AEMO's NTNDP naming convention in the '2015 NTNDP Status' column.

Constraint equation and description	2015 marginal values (2014)	Ranking: 2015 marginal value	2015 hours (2014)	Ranking: 2015 duration	2015 NTNDP status	Commentary
NSA_S_POR03_10 Run Port Lincoln generators in accordance with Network Support Agreement	2,577,658 (0)	1	15.7		E-S4	ElectraNet dispatches this generation under a network support agreement to supply the Port Lincoln load under islanded conditions The use of network support to supply Port Lincoln was shown to be economic in the 2013 Eyre Peninsula RIT-T assessment and will continue indefinitely, subject to periodic review
NSA_S_POR01_10 Run Port Lincoln generators in accordance with Network Support Agreement	2,509,174 (0)	2	15.3			
NSA_S_POR01+POR03_20 Run Port Lincoln generators in accordance with Network Support Agreement	137,073 (0)	12	0.8			
NSA_S_POR01_15 Run Port Lincoln generators in accordance with Network Support Agreement	82,190 (0)	26	0.5			
NSA_S_POR01_ISLD Run Port Lincoln generators in accordance with Network Support Agreement	0 (3,587,599)	N/A	0	N/A		

Constraint equation and description	2015 marginal values (2014)	Ranking: 2015 marginal value	2015 hours (2014)	Ranking: 2015 duration	2015 NTNDP status	Commentary
S_LB3_0 Lake Bonney Wind Farm No. 3 constrained to 0 MW	517,724 (60,541)	3	137.5 (45.6)	14	-	This constraint is invoked by AEMO to manage outages on the transmission network
V>>S_HYML_1 Avoid overload of the remaining in-service Heywood 500/275 kV transformer if an outage of South Australia's largest on-line generator was to occur, at times when the other transformer is not in service	89,547 (29,748)	23	210.0 (19.6)	9	-	AusNet Services installed a third 500/275 kV transformer at Heywood in December 2015, which has alleviated these constraints Incremental increases in available interconnector transfer are being released as inter-network testing progresses
V>S_NIL_HYTX_HYTX Avoid overload of one Heywood 500/275 kV transformer if an outage of the other one was to occur	400,941 (159,592)	4	818.1 (473.9)	1	-	
V>S_460 Avoid overload of one Heywood 500/275 kV transformer if an outage of the other one was to occur	106,585 (59,053)	18	263.6 (159.3)	6		
S>V_NWRB2_RBNW1 Avoid overload of the Robertstown to North West Bend 132 kV line No. 1, at times when the Robertstown to North West Bend 132 kV line No. 2 is not in service	21,343 (0)	58	94.2 (0.0)	19	E-S3	These constraints have been alleviated by the uprate of the Robertstown to North West Bend 132 kV line No. 1, which was completed by ElectraNet in 2015 - refer to section 7.1.1 for more details
S>V_NIL_NIL_RBNW Avoid overload of the Robertstown to North West Bend 132 kV line No. 1 during system normal conditions	270,134 (2,478,435)	5	451.3 (239.8)	4		

Constraint equation and description	2015 marginal values (2014)	Ranking: 2015 marginal value	2015 hours (2014)	Ranking: 2015 duration	2015 NTNDP status	Commentary
S>XKHTB1+2_SETX_SETX Avoid overload of one South East 275/132 kV transformer if an outage of the other one was to occur, at times when both Keith to Tailem Bend 132 kV lines are not in service	247,093 (0)	6	25.0 (0.0)	32	-	This constraint was due to concurrent planned outages of the Keith to Tailem Bend 132 kV lines. Implementation of a generation runback scheme, planned for completion in 2016, will alleviate this constraint
V^SML_NSWRB_2 Avoid voltage collapse in southern NSW if an outage of the Darlington Point to Buronga 220 kV line was to occur, at times when the NSW Murraylink runback scheme is not in service	207,805 (147,459)	7	72.3 (62.8)		-	AEMO monitors the performance of this constraint
V>>SML_NIL_7A Avoid overload of the Ballarat North to Buangor 66 kV line if an outage of the Ballarat to Waubra to Horsham 220 kV line was to occur	186,019 (48,808)	8	80.7 (42.6)	23	E-V4	AEMO's 2016 Victorian Transmission Annual Planning Report indicates that an automatic bus-splitting control scheme at Buangor 66 kV substation will address this constraint, and is due for completion in November 2016
VSML_220 Avoid exceeding Murraylink interconnector maximum capacity during system normal conditions	183,598 (488)	9	123.4 (1.6)	15	-	This constraint could be alleviated by duplicating the Murraylink HVDC interconnector, or by establishing a high capacity interconnector between the Northern region of South Australia and the eastern states
S>>NIL_SETB_KHTB1 Avoid overload of the Keith to Tailem Bend 132 kV line No. 1 if an outage of one of the South East to Tailem Bend 275 kV lines was to occur	181,073 (166,195)	10	172.0 (196.5)	13	-	These constraints are due to the relatively low rating of the Keith to Tailem Bend N0. 1 132 kV line in the South East to Tailem Bend corridor Congestion will be alleviated by the decommissioning of this line as part of the Heywood interconnector upgrade, see section 7.1.2.1 for further details

Constraint equation and description	2015 marginal values (2014)	Ranking: 2015 marginal value	2015 hours (2014)	Ranking: 2015 duration	2015 NTNDP status	Commentary
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	82,929 (17,198)	24	759.7 (236.2)	2	-	AEMO monitors the performance of these constraints AEMO's 2016 Victorian 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 the current generation surplus in Victoria remains over the next 10 years
V::N_NIL_V3 Avoid transient instability of generators if an outage of one of the 500 kV lines between Heywood and South Morang was to occur	18,197 (2,676)	61	191.8 (39.6)	10		
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	9,394 (7)	77	73.7 (0.4)	30		
V>>V_NIL_2A_R Avoid overload of the South Morang 500/330 kV transformer during system normal conditions	80,139 (24,342)	27	705.2 (310.8)	3	E-V1	AEMO's 2016 Victorian Transmission Annual 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
V>>V_NIL_2B_R Avoid overload of the South Morang 500/330 kV transformer during system normal conditions	13,560 (23,026)	68	184.4 (515.8)	11		
V>>S_NIL_SETB_SGKH Avoid overload of the Snuggery to Keith 132 kV line if an outage of one of the South East to Tailem Bend 275 kV lines was to occur	92,337 (63,809)	22	265.0 (287.4)	5	-	This constraint is due to the relatively low rating of the Snuggery to Keith 132 kV line in the South East to Tailem Bend corridor Congestion will be alleviated by the decommissioning of this line as part of the Heywood interconnector upgrade, see section 7.1.2.1 for further details

Constraint equation and description	2015 marginal values (2014)	Ranking: 2015 marginal value	2015 hours (2014)	Ranking: 2015 duration	2015 NTNDP status	Commentary
V::S_NIL_MAXG_AUTO Avoid transient instability of generators if an outage of South Australia's largest on-line generator was to occur	118,157 (0)	14	241.1 (0.0)	7	-	This constraint will be alleviated by the installation by mid-2016 of series capacitors at Black Range, on each of the South East to Tailem Bend 275 kV lines, as part of the Heywood interconnector upgrade
N^^V_NIL_1 Avoid voltage collapse in southern NSW if an outage of Victoria's largest on-line generator was to occur	94,201 (701,455)	21	211.7 (208.8)	8	-	AEMO monitors the performance of this constraint

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 (perhaps driven by climate change policies); 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 2015 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 New South Wales or Victoria	Augmentation may reduce losses; support development of renewable generation; improve export/import capability; and enhance reliability to the Riverland in South Australia, and Western Victoria	Build a new single or double circuit 275 kV line from Robertstown to Monash, and establish a new interconnector to New South Wales or Victoria Alternative routes for a new interconnector could be from Tungkillo in South Australia to Horsham in Victoria, or a 500 kV high capacity interconnector from Davenport in South Australia to Mount Piper in New South Wales	400 MW to 2,000 MW capacity increase	1-2 years RIT-T 3-5 years detailed design and delivery	300–700
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	400-600 MW increase in line section capacity	1-2 years RIT-T 2 years delivery	40–60

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 275 kV AC double circuit line with twin conductors	1200 MW capacity increase	1-2 years RIT-T 5 years easement acquisition, detailed design and delivery	300–400
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
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)
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	5–10

4.4 Future network congestion

The committed upgrade of the Heywood Interconnector and completed upgrade of the Robertstown to North West Bend #1 132 kV line will increase the capability of the ElectraNet network to import and export power across both interconnectors. Following this increase in capability, the generally higher flows across both interconnector corridors are at times expected to remain constrained by network import and export limitations (Table 4-5).

South Australia could see a further significant increase in connected renewable generation, partly depending on future government policy to achieve Australia's emissions reduction targets (as discussed in section 3). Further development of renewable generation will also be boosted if a new interconnector to New South Wales or Victoria proves to be economically viable (see section 3.2.3).

Future network congestion patterns will depend on future generator connection locations and limitations that could bind as a result of such additional renewable generation connections are highlighted in Table 4-5 along with forecast limitations on ElectraNet's electricity transmission network. 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 interconnector	Constrained flow: import or export; potential impact of new renewable connection (R)	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 7.2.5.4
Mid North Region: thermal ratings of 275 kV lines between Davenport and Brinkworth	Depends on future generation connections	Intra-regional	N/A (R)	Table 4-4 (first entry)
Mid North Region: thermal ratings of 275 kV lines between Davenport and Robertstown	Depends on future generation connections	Intra-regional	N/A (R)	Section 7.2.5.1
Mid North Region: thermal ratings of 132 kV lines between Robertstown and North West Bend	Existing	Murraylink	Export	Section 7.2.3.2
Mid North Region: thermal ratings of 132 kV lines between Waterloo and Templers	Existing	Intra-regional	N/A (R)	Section 7.2.5.3

Limitation	Status	Affected interconnector	Constrained flow: import or export; potential impact of new renewable connection (R)	Reference to potential mitigating project(s)
Mid North Region: thermal ratings of 132 kV lines between Waterloo East and Robertstown	Existing	Murraylink	Export	Section 7.2.3.3
North West Bend, Berri and Monash: voltage limitations	Existing	Murraylink	Export	Section 7.2.5.6
Robertstown 275/132 kV transformers: thermal ratings	Depends on future generation connections	Intra-regional and Murraylink	Export (R)	Section 7.2.5.2
South East Region: thermal ratings of 275 kV lines between Tailem Bend and Tungkillo	Forecast post-Heywood interconnector upgrade	Heywood	Import and export	Sections 7.2.3.1 and 7.2.5.5
South East Region: voltage stability limitations	Existing, and forecast post-Heywood interconnector upgrade	Heywood	Import and export	Section 7.2.5.5
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 7.2.5.5

Congestion in Victoria frequently impacts the transfer capability of the Heywood and Murraylink interconnectors. This will occur more often as the 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 (2015–16) 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 historical data (section 5.1) to forecast demand (section 5.2).

5.1 Summer demand review[20]

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 grape districts).

According to the Bureau of Meteorology, the 2015–16 summer was Adelaide's fourth hottest on record with a summer daytime average maximum temperature of 31°C, making it Adelaide's warmest summer since 2000-01. Highlights include:

- Adelaide recorded higher than average daily maximum and minimum temperatures (Table 5-1), with seven days in December recording maxima above 40°C.[21]
- For South Australia overall, the mean maximum temperature was in the top ten warmest on record, with an extended period of extreme heat experienced in early summer at several locations.[22]
- State-wide demand reached a maximum of 3034 MW[23] on Thursday 17 December 2015.
- Demand exceeded 2700 MW on six occasions during the 2015–16 summer (Table 5-2).

[20] Connection points in South Australia experience maximum demands in summer – ElectraNet doesn't collect winter maximum demand data or use it in its planning.
[21] *Adelaide in summer 2015-16: Warm days and nights, average rainfall*, Bureau of Meteorology, 1 March 2016 – available at: http://www.bom.gov.au/climate/current/season/sa/adelaide.shtml
[22] *South Australia in summer 2015-16: Warm days and nights, average rainfall*, Bureau of Meteorology, 1 March 2016 – available at: http://www.bom.gov.au/climate/current/season/sa/summary.shtml
[23] This value includes demand supplied by non-scheduled and embedded generation, but excludes demand provided by rooftop solar PV generation.

Table 5-1: 2015–16 summer temperature data compared with long term trends

	December		January		February		March	
	Long term trend	2015–16	Long term trend	2015–16	Long term trend	2015–16	Long term trend	2015–16
Max temp (˚C)	43.4	42.8	45.7	39.3	44.7	38.9	41.9	38.4
Date of max temp	19-12-2013	19-12-2015	28-01-2009	12-01-2016	02-02-2014	22-02-2016	06-03-1986	05-03-2016
Average max temperature	27.2	32.2	29.4	30.7	29.5	28.9	26.4	28.6
Days* >30˚C	9.8	18	13.5	16	12.6	11	7.8	16
Days* >35˚C	3.6	12	6.2	7	5.5	3	2.6	4
Days* >40˚C	0.7	6	1.7	0	0.9	0	0.2	0
Difference between 2015–16 average max and long term trend (°C)	5.0		1.3		-0.6		2.2	

*Mean days for long term trend data, actual days for 2015-16 data.

Table 5-2: Highest demand periods in summer 2015–16.

Date	Maximum demand[24]	Temperature demand index
Thursday 17 December	3034	37.8
Friday 18 December	2912	36.7
Wednesday 16 December	2911	36.1
Saturday 19 December	2890	38.3
Monday 7 December	2881	36.5
Thursday 12 January	2792	34.8

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

SA Power Networks has previously determined that a threshold value of 38 (comprised of a 67% weighting to the day's maximum temperature, 18% weighting to the overnight minimum and a 15% weighting to the previous day's average temperature[25]) occurring after Australia Day provides the necessary temperature conditions to achieve 10% POE at a state level.

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

24 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.
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.

includes the summer holiday period and weekends. Hence, over the last 100 years, it can be assumed there have been 9–10 weather events above this threshold at times that are expected to result in 10% POE demand conditions. As high demand is primarily driven by extreme temperature conditions during non-holiday periods, a temperature index above 38 on a working day has been considered an appropriate indicator of 10% POE demand conditions.

Despite the above average temperatures, the temperature index reached 38 only once, on a weekend in mid-December (Figure 5-1). The five next highest values of the temperature index occurred in early December, and relate to the above-average maximum daytime temperatures experienced early that month. The highest value of the temperature index on a weekday after Australia Day was 34.4°C on Monday 22 February when demand reached 2612 MW. ElectraNet therefore considers that the 10% POE maximum demand level for the 2015-16 summer would have been higher than the maximum demand of 3034 MW that occurred on Thursday 17 December.

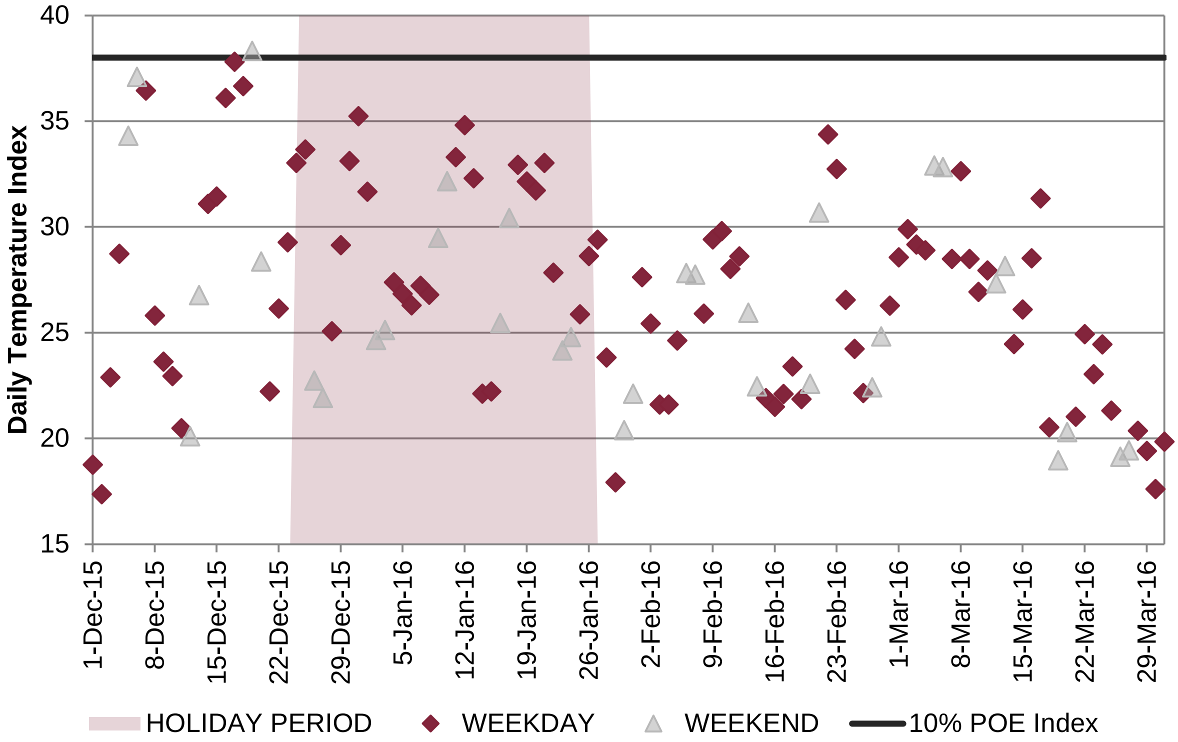

Figure 5-1: Daily temperature index for summer 2015–16.

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 2015-16, most connection points recorded maximum demands that were between 85% and 100% of their forecast maximum demand.

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

AEMO and SA Power Networks' 2016 reviews of connection point forecasts will consider the measured maximum demands from summer 2015-16.

Table 5-3: Connection points that recorded maximum demands more than 100% of ElectraNet's 10% POE demand forecast in summer 2015–16.

	ElectraNet 10% POE demand forecast (MW)	AEMO 10% POE forecast (MW)	Actual Maximum (MW)	Date and time of maximum demand (Australian central daylight time)
Baroota	7.7	8.0	7.8	7:30 PM Saturday 19 December
Blanche	32.4	34.1	33.0	3:00 PM Wednesday 13 January
Hummocks	13.1	13.8	13.4	7:30 PM Wednesday 16 December
North West Bend	26.9	28.5	28.3	6:30 PM Saturday 19 December

Table 5-4: Connection points that recorded maximum demands less than 85% of ElectraNet's 10% POE demand forecast in summer 2015–16.

	ElectraNet 10% POE demand forecast (MW)	AEMO 10% POE forecast (MW)	Actual Maximum (MW)	Date and time of maximum demand (Australian central daylight time)
Mount Barker/Mount Barker South	99.3	89.0	83.2	7:00 PM Thursday 17 December
Mount Gambier	21.6	21.9	18.1	6:30 PM Wednesday 16 December
Penola West	8.9	9.6	6.9	6:00 PM Tuesday 8 March
Snuggery Rural	15.9	15.2	13.1	7:30 PM Wednesday 30 December

5.2 Demand forecast

ElectraNet considers that its customers are best placed to understand their needs. Given this, and in accordance with Rules clause 5.11.1, ElectraNet annually receives 10-year demand forecasts from SA Power Networks and direct connect customers. ElectraNet and SA Power Networks work together to determine and agree on any adjustments required to account for 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 June 2015. Details of the forecast can be found in ElectraNet's *2016 South Australian Connection Point Forecasts Report.*[26] This report includes a reconciliation of demand forecasts with AEMO's 2015 National Electricity Forecast Report (NEFR) and is summarised in part within the sections below. In most cases there is very little change in the projections of future demand for most connection points compared to the demand forecast provided by SA Power Networks in September 2014, which was the basis for the augmentation plans presented in the *2015 Transmission Annual Planning Report*. In June 2015, AEMO published a minimum demand forecast for South Australia as part of the 2015 National Electricity Forecasting Report. ElectraNet has used that forecast to determine future needs for improved voltage control on the Main Grid at times of minimum demand in South Australia.

5.2.1 Review of 2015 National Electricity Forecasting Report

AEMO publishes an annual state-wide demand forecast for South Australia as part of the NEFR. In 2015, AEMO forecast that:

- state-wide demand would increase at an annual average rate of 0.4 percent per annum until 2017–18.
- From 2018–19, 10% POE demand to experience growth of around 0.6 percent.
- average demands to gradually reduce over the forecast period.
- In constrast, 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 2023-24.

AEMO's 2015 NEFR 10% POE medium growth forecasts for South Australian maximum, average[27] 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.

2016 NATIONAL ELECTRICITY FORECASTING REPORT

AEMO published the 2016 NEFR in June 2016, which has South Australian forecasts that differ significantly from the ones in the 2015 NEFR.

10% POE maximum demand is now forecast to reduce steadily to around 2,600 MW by summer 2028-29, and then remain steady for the rest of the forecast period. Preliminary consideration shows that this is unlikely to have any effect on the plans we present in this report.

Minimum demand is forecast to continue to reduce rapidly, but at a slower rate than indicated in the 2015 NEFR: zero net demand for the 90% POE forecast is now expected to be reached in summer 2028-29. This may delay the need for the 275 kV reactor that is described in section 7.2.3.6.

We will fully review the impact of the 2016 NEFR on our plans before we submit our final 2018 – 2023 revenue proposal.

[26] Available from electranet.com.au.
[27] ElectraNet has calculated average demand forecasts from AEMO's forecasts of annual energy.

See the sidebar on the previous page for preliminary consideration of the impact that AEMO's 2016 NEFR is expected to have on our plans.

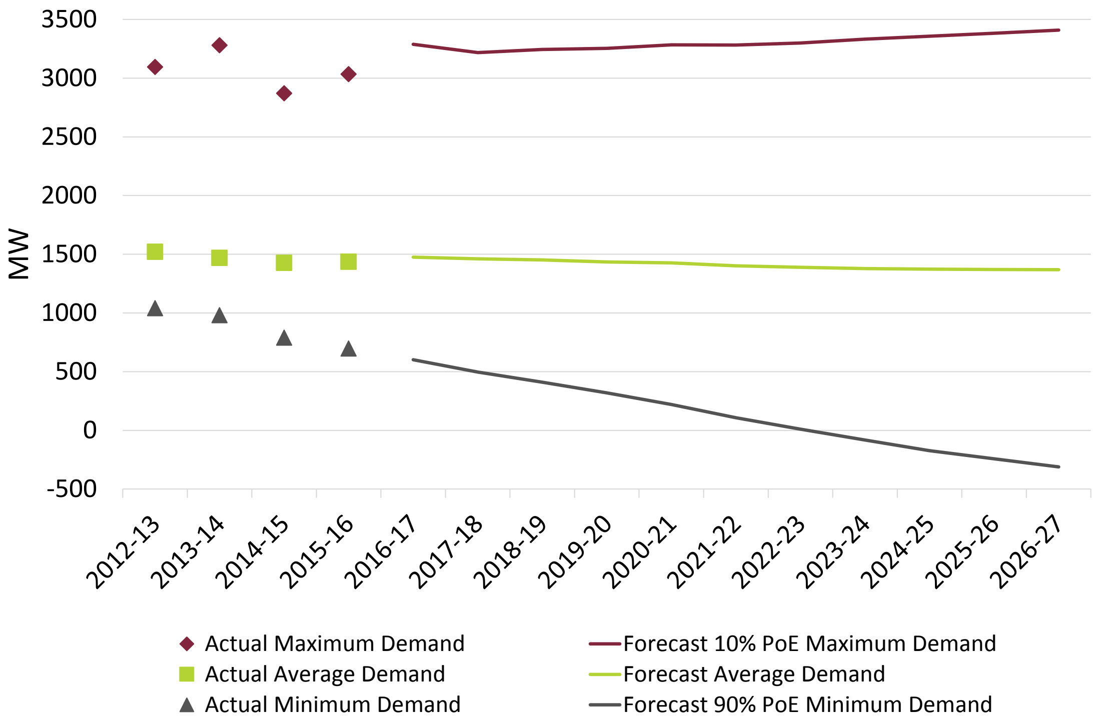

Figure 5-2: AEMO's 2015 SA medium growth forecasts

Source: AEMO 2015 NEFR SA Operational Demand (2015-16 actuals from ElectraNet)

5.2.2 Connection point forecasts and reconciliation

In October 2015, 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.[28]

At an aggregate level, AEMO's and ElectraNet's connection point forecasts are both reconciled to AEMO's state-level forecast from the 2015 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.

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

6. Connection opportunities

Available supply in the South Australian region comes from local generation as well as the Heywood and Murraylink interconnectors. Available supply only slightly exceeds forecast maximum demand as described in AEMO's 2015 Electricity Statement of Opportunities (ESOO) update, especially following the closure of the Northern Power Station.[29]

ElectraNet encourages potential new generators or customers, to contact its Business 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 the 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.

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. 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).

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, Le Fevre, 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 network 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 the dispatch of other in-service conventional generators and interconnector flow was decreased according to a pre-defined generation stack to maintain the supply-demand balance. The impact of run back schemes was not considered in the assessment.

[29] Available at: http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities

Table 6-1: Network conditions used to assess the ability to connect new generation

Network condition	Demand (MW)	Wind	Number of conventional generators on-line	Heywood transfer (MW)	Murraylink transfer (MW)
High demand low wind	3200	9%	33	650 (import)	0
High demand high wind	3200	75%	14	300 (import)	0
Medium demand low wind	1450	9%	5	650 (import)	0
Medium demand very high wind	1400	90%	1	0	0

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 Heywood interconnector upgrade is expected to be completed in July 2016, with additional available transfer capacity to be released in stages following inter-network testing. The upgraded capacity was included in the calculation of indicative generator connection capability. Additional incremental upgrades along key transmission corridors, including across the Heywood interconnector corridor, would further alleviate forecast thermal constraints. This would help 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
- 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 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 the study. In some cases, it may be feasible to connect larger generators if low cost upgrades can increase the available capacity of upstream assets. The study does incorporate the impact of committed projects, including those included in ElectraNet's *2015–2018 Network Capability Incentive Parameter Action Plan* (NCIPAP).[30]

[30] Available from electranet.com.au.

6.2 Connection 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 supply demand and provide a reliable supply arrangement.

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. 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 (Table 6-2). 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:

- 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.

It is important to note the following limitations of this assessment.

- 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 reduce the additional load that could be accommodated at other connection points, particularly for connection points in close electrical proximity
- The loads provided represent the capability of the existing transmission network only, and do not account for any additional transformer capacity that may be required to facilitate connection at voltage levels below 275 kV or 132 kV (as applicable)
- 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.

6.3 Summary of connection opportunities

An indicative summary of the ability of ElectraNet's network to easily 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.

We encourage any potential new generator or customer to contact the Business Development Team (connection@electranet.com.au) to discuss their needs.

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

Connection point	Voltage level (kV)	Additional generation that could be connected in 2018–19 (MW)	Additional load that could be connected in 2018–19 (MW)
Main Grid			
Belalie	275	>200	>200
Blyth West	275	10	>200
Brinkworth	275	20	>200
Bungama	275	10	>200
Canowie	275	>200	>200
Cherry Gardens	275	100	>200
Cultana	275	>200	120
Davenport	275	>200	150
Mokota	275	>200	>200
Mt Lock	275	>200	>200
Robertstown	275	>200	40
South East	275	0	>200
Tailem Bend	275	20	>200
Tungkillo	275	110	>200
Templers West	275	20	180
Eastern Hills			
Angas Creek	132	140	70
Cherry Gardens	132	150	100
Kanmantoo	132	60	60
Mannum	132	150	50
Mobilong	132	170	40
Mt Barker	132	>200	120
Mt Barker South	275	110	>200

Connection point	Voltage level (kV)	Additional generation that could be connected in 2018–19 (MW)	Additional load that could be connected in 2018–19 (MW)
Eyre Peninsula			
Port Lincoln Terminal	132	0	<5
Cultana	132	150	50
Stony Point	132	40	30
Whyalla Central	132	120	50
Whyalla LMF	132	50	50
Wudinna	132	0	<5
Yadnarie	132	0	10
Mid North			
Ardrossan West	132	0	40
Baroota	132	0	<5
Brinkworth	132	0	>200
Clare North	132	0	100
Dalrymple	132	0	20
Dorrien	132	30	60
Hummocks	132	0	40
Kadina East	132	0	40
Robertstown	132	150	40
Templers	132	50	90
Templers West	132	30	60
Waterloo	132	0	40
Riverland[31]			
Berri	132	60	20
Monash	132	120	20
North West Bend	132	150	30
South East			
Blanche	132	0	30
Keith	132	0	20
Kincraig	132	0	20
Mt Gambier	132	0	30
Penola West	132	0	20
Snuggery	132	0	40
South East	132	0	50
Tailem Bend	132	0	70

[31] New generation in the Riverland could constrain Murraylink interconnector dispatch in some situations, and *vice versa*.

Connection point	Voltage level (kV)	Additional generation that could be connected in 2018–19 (MW)	Additional load that could be connected in 2018–19 (MW)
Upper North			
Davenport	132	160	120
Leigh Creek South	132	<5	<5
Mt Gunson	132	20	60
Neuroodla	132	<5	<5
Pimba	132	10	40

6.4 Proposed new connection points

ElectraNet has proposed a new connection point in the Mid North to meet localised growing demand, and has established a new connection point on the Main Grid to connect a new wind farm (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
Mt Lock	Main Grid	2016 – energised 15 June 2016	275	Turn the Davenport to Canowie 275 kV line in/out at Mt Lock and establish a 275 kV bus Hornsdale wind farm to connect at 275 kV and establish a single transformer 275/33 kV connection substation, with ability to add more 275/33 kV transformers
Gawler East	Mid North	2019	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 7.2.3.5 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, but low long term constraint risk solution to the customer. Where a number of generators and/or loads are developed in close proximity, it is important to provide efficient connections wherever possible. This approach is intended to minimise network constraints for the customer, maximise network utilisation, reduce connection costs, and facilitate efficient and sustainable long-term transmission network development.

Using this approach, wind farm developments in the Mid North are connected to ensure that loading on the parallel 275 kV lines between Port Augusta and Adelaide is as balanced as possible. 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 efficiently use the existing shared network over the long term. ElectraNet may recommend generators and load customers connect to a specific network location if it is efficient to do so. ElectraNet will also specify the appropriate configuration for that connection. Nodal connection points allow parallel transmission lines to be tied together and new generation to be efficiently placed in the system. This further balances line loadings and maximises thermal transfer capability on the existing network.

ElectraNet has identified 13 potential connection hubs in the South Australian transmission network (Figure 6-1).

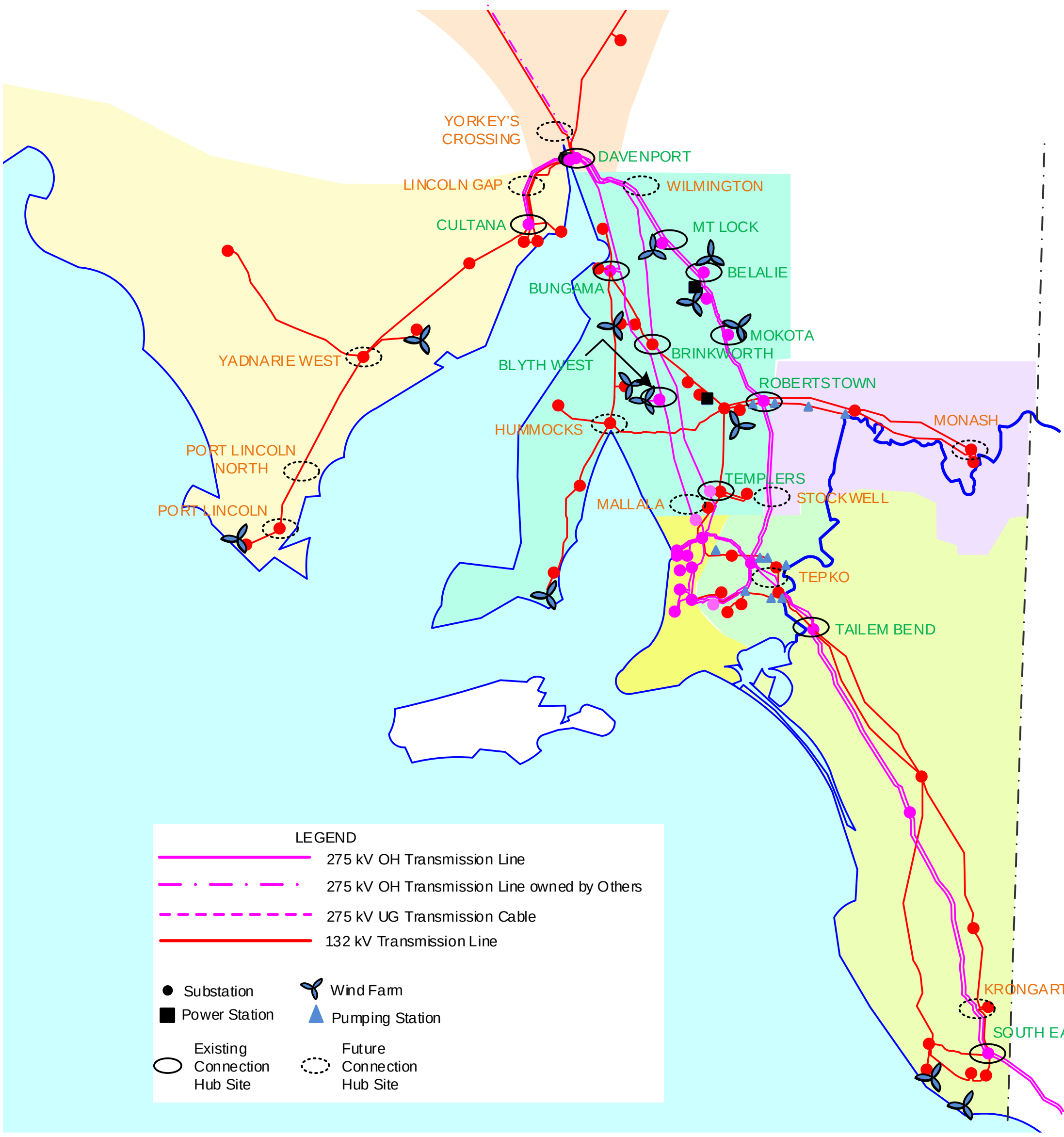

Figure 6-1: Current and possible South Australian future transmission connection hubs

7. Transmission network developments

Over the past year, ElectraNet has completed and committed to several projects to remove network limitations and address asset condition (section 7.1). ElectraNet and SA Power Networks also analyse the expected future operation of the South Australian network taking into account forecast loads, future generation, market network services, demand side participation and transmission developments. The resulting transmission network development plans are presented for feedback (section 7.2), along with planning assessments for significant replacement and refurbishment projects (section 7.3). A comprehensive summary of committed, pending and proposed augmentation, security and compliance and replacement and refurbishment projects is provided in Appendix G.

Estimated project costs quoted in this chapter are presented in 2015–16 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.

7.1 Completed, committed and pending projects

7.1.1 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 2015 and 30 April 2016

Project description	Region	Project category	Asset in service
Mt Gunson 132/33 kV connection point replacement Selected end-of-life plant was replaced at Mt Gunson substation with modern-day equipment and a 10 MVA 132/33 kV transformer was installed	Upper North	Replacement	29/06/2015
Neuroodla 132/33 kV connection point replacement Neuroodla substation was rebuilt within the existing substation site and a 10 MVA 132/33 kV transformer was installed as well as modern-day equipment	Upper North	Replacement	17/07/2015
Munno Para New 275/66 kV connection point ElectraNet and SA Power Networks' joint planning and regulatory test found that a new 275/66 kV connection point at Munno Para would provide the most economical solution to limitations on the SA Power Networks distribution network. In response, a new 275/66 kV 225 MVA connection point substation was built at Munno Para, connecting into the Para to Bungama 275 kV line. Neutral earthing reactors were installed on the Para and Parafield Gardens West transformers	Metropolitan	Augmentation	03/08/2015

Project description	Region	Project category	Asset in service
Robertstown – North West Bend #1 and #2 132 kV lines dynamic line ratings Dynamic line rating on the Robertstown - North West Bend #1 and #2 132 kV lines was installed and commissioned to increase available Murraylink transfers, particularly during extreme summer temperature events, from South Australia into Victoria	Riverland	Augmentation	20/10/2015[32]
Robertstown – North West Bend #1 and #2 132 kV line uprate The Robertstown - North West Bend #1 132 kV line was uprated to reduce constraints on available Murraylink transfers, particularly during extreme summer temperature events, from South Australia into Victoria	Riverland	Augmentation	26/10/2015
South East additional 275 kV circuit breakers A substandard circuit breaker arrangement at South East substation, which constrained the Heywood Interconnector and placed network security and reliability at risk, was addressed by installing additional circuit breakers and associated switchgear; metering; and protection	Main Grid	Security and compliance	23/12/2015
Para Unit asset replacements The 275 kV, 132 kV and 66 kV secondary systems were replaced along with associated telecommunications systems, control buildings and selected primary plant at the Para substation. This project was the result of a detailed condition assessment and asset replacement risk analysis. The project scope and schedule were extended to include unit asset replacements required in the 2013–18 period	Metropolitan	Replacement	18/03/2016
Davenport Under-voltage Load Shedding An under-voltage load shedding scheme was implemented on the Olympic Dam exit at Davenport substation to mitigate risk of voltage collapse following closure of Northern Power Station	Main Grid	Security and compliance	29/04/2016
SA Water Morgan-Whyalla Pump Station #2 Rebuild the Morgan to Whyalla pumping station #2 supply site to current day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Riverland	Replacement	08/05/2016

[32] Dynamic line rating equipment is commissioned and in service, but communication issues are still to be resolved.

7.1.2 Committed projects

Committed projects are projects where the RIT-T has been completed (where required), and approval has been given by the ElectraNet Board. 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 Morgan-Whyalla Pump Station #3 Rebuild the Morgan to Whyalla pumping station #3 supply site to current day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Riverland	Replacement	July 2016
Heywood interconnector upgrade The Heywood interconnector will be incrementally augmented to raise nominal transfer limits from ±460 MW to ±650 MW. This has been shown to deliver market benefits using the RIT-T. A third 500/275 kV transformer at Heywood terminal station will be installed along with series compensation[33] on the South East to Tailem Bend 275 kV lines and the existing 132 kV transmission system will be reconfigured between Snuggery, Keith and Tailem Bend. See section 7.1.2.1 for more details	Main Grid/ South East	Augmentation	July 2016[34]
SA Water Morgan-Whyalla Pump Station #1 Rebuild the Morgan to Whyalla pumping station #1 supply site to current day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Riverland	Replacement	September 2016
Dalrymple Substation Upgrade Install an additional 25 MVA 132/33 kV transformer at Dalrymple substation, with associated switchyard reconfiguration	Mid North	Connection	November 2016
Tailem Bend – Keith #2 132 kV line insulator replacement All porcelain disc insulator assemblies that have reached end of life on the Tailem Bend to Keith #2 132 kV transmission line will be replaced to extend the life of the transmission line by at least 15 years	South East	Refurbishment	November 2016

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

[34] 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	Expected Service Date
SA Water Morgan-Whyalla Pump Station #4 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	Replacement	November 2016
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 on the Brinkworth to Mintaro 132 kV transmission line. This will extend the life of the transmission line by at least 15 years	Mid North	Refurbishment	November 2016
Para SVC Secondary Systems Replace Para SVC secondary systems and install and integrate a 50 Mvar switched 275 kV reactor	Main Grid	Replacement	November 2016
SA Water Mannum-Adelaide Pump Station #3 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	Replacement	May 2017
Tailem Bend Substation Upgrade 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	Security / Compliance	June 2017
SA Water Mannum-Adelaide Pump Station #2 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	Replacement	July /2017
SA Water Mannum-Adelaide Pump Station #1 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	Replacement	July 2017
Para-Brinkworth-Davenport Hazard Mitigation 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	Refurbishment	September 2017

Project description	Region	Project Category	Expected Service Date
Various unit asset replacements Individual unit assets, such as circuit breakers, voltage transformers, current transformers or protection relay sets that have reached end of life will be replaced at 36 substations	Various	Replacement	December 2017

The following sections provide additional detail for major committed projects (>5 M expenditure at a single site): the Heywood interconnector Upgrade (section 7.1.2.1); the installation of the second transformer at Dalrymple Substation (section 7.1.2.2); the replacement of Para SVC secondary systems (section 7.1.2.3); and the Tailem Bend Substation Upgrade (section 7.1.2.4).

7.1.2.1 Heywood interconnector upgrade

Scope of Work: Install series compensation on the South East–Tailem Bend 275 kV lines and increase the transfer capacity of the South East to Tailem Bend corridor

Estimated Cost: $35–45 million (SA component)

Timing: July 2016

Project Status: Committed, construction in progress

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

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

Two main limitations that currently affect the Heywood interconnector have been identified: thermal capabilities and voltage stability limitations in south-east South Australia and transformer capacity at Heywood. The import and export capability of the interconnection would increase if both of these limitations were alleviated. ElectraNet and AEMO consider that increasing the capability of the interconnection will lead to an overall increase in net market benefit in the NEM. This has been demonstrated in the analysis presented in the project assessment conclusions report (PACR) that was published jointly by AEMO and ElectraNet in January 2013.

In August 2013, the AER determined that the preferred option in the PACR (described below and in Figure 7-1) satisfies the RIT-T as per section 5.16.6 of the Rules. The AER made its contingent project decision in March 2014 and approved the incremental revenue for the project requested by ElectraNet.

The project scope includes:

- a third 500/275 kV transformer at the Heywood 500 kV terminal station, to be delivered by AEMO and AusNet Services (commissioned in December 2015)

- series compensation of the two South East to Tailem Bend 275 kV lines
- reconfiguration of substation assets and the existing 132 kV transmission system to allow increased use of 275 kV transmission line capacity
- a South East 275/132 kV transformer control scheme
- a protection and control scheme that will bypass the series capacitors if either sub-synchronous oscillations or a network condition that could lead to the growth of sub-synchronous oscillations is detected.

In developing the network augmentation components, due consideration has been given to alleviating most of the existing intra-regional network limitations in south-east South Australia. This upgrade is expected to have a material impact on inter-regional transfer as it will increase interconnector capability in both directions by about 40% when compared to pre-upgrade transfer limits. The net market benefits are estimated at more than $190 million (in present value terms) over the life of the project with positive net benefits commencing from the first year of operation.

Inter-regional testing began after installation of the third Heywood transformer and is being performed in stages as part of the commissioning tests for the series compensation installation. Following each test, the increased transfer capability is being released in steps following formal endorsement by the Plant Modelling Working Group. The full 650 MW capacity is expected to be released in the second half of 2016.

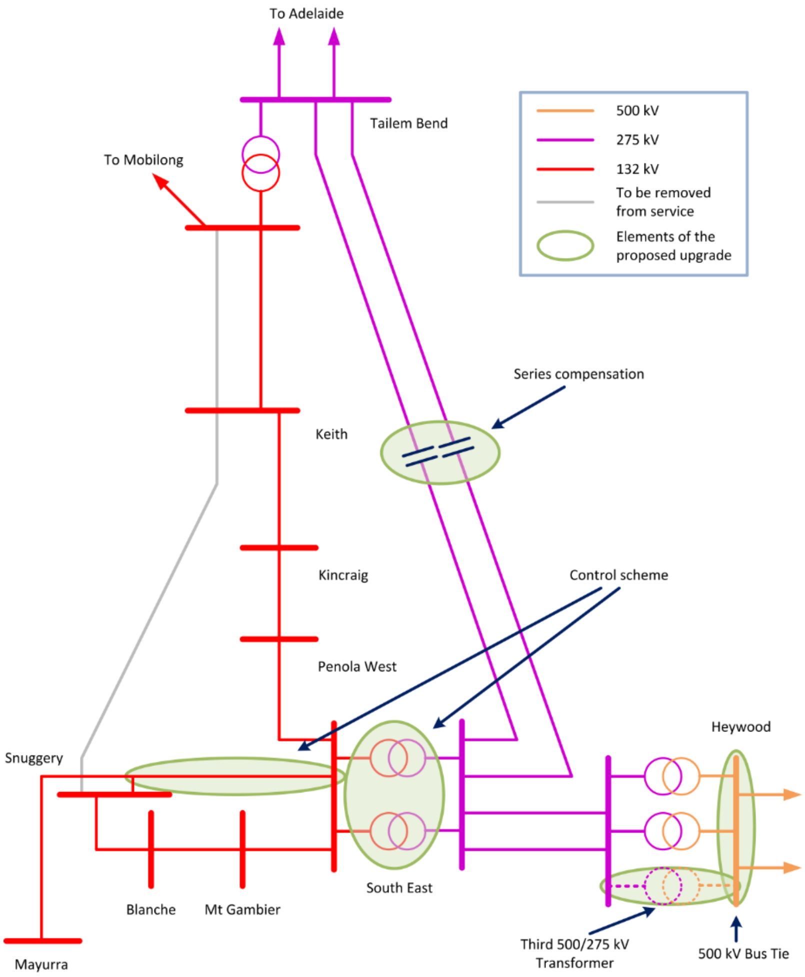

Figure 7-1: Components of Heywood interconnector upgrade

7.1.2.2 Install a second 25 MVA 132/33 kV transformer at Dalrymple Substation

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

Estimated Cost: \$12–14 million (\$8–10 million ElectraNet costs)

Timing: November 2016

Project Status: Committed

Project Need:

The ETC will assign the Dalrymple connection point to reliability category 2 from 1 December 2016. This means that the equivalent transformer capacity at Dalrymple must be adequate to supply the agreed maximum demand with one transformer out of service. The existing connection point will not meet this required level of reliability as only one transformer is installed at Dalrymple, and there is no currently available network support arrangement.

As the most credible option to overcome this constraint exceeded five million dollars in expenditure, ElectraNet carried out public consultation in accordance with the RIT-T process. A project assessment conclusions report was published in November 2013 and no submissions were received during the RIT-T public consultation periods.

However, ElectraNet subsequently reviewed the economic case for the Dalrymple upgrade and found a lower market benefit than that in the original analysis. In response to this reduced market benefit, ElectraNet significantly reduced the scope and cost of the project, by marginally reducing reliability, operability and flexibility for future expansion of the site. A revised economic analysis has confirmed that a reduction in scope does produce a net market benefit. ElectraNet does not envisage that this project will have any material impact on inter-regional transfer.

7.1.2.3 Para SVC secondary systems replacement

Scope of work: Replace Para SVC secondary systems and install and integrate a 50 Mvar switched 275 kV reactor

Estimated cost: \$20-25 million

Timing: November 2016

Project status: Committed

Project need:

The Static Var Compensator (SVC) secondary systems at Para substation have reached the end of their service lives. The key issue is the limited availability of critical spares to support maintenance on the existing systems.

The SVC primary plant is estimated to have a future life of around fifteen years, so a mid-life replacement of the control system is required to maintain reliability of the SVCs for their remaining lives.

Installing a modern digital control system will provide additional benefits by enabling automatic switching of capacitive and reactive plant at Para for increased dynamic reactive range to better manage system voltage levels.

In addition, it was identified following the announcement of the closure of Northern Power Station that inductive reactive power support may be needed at Para substation during the required SVC outages, with Northern Power Station out of service. The optimal solution is to bring forward the installation of a 50 Mvar reactor at Para substation which was previously planned for the 2018-23 period.

7.1.2.4 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

Timing: June 2017

Project Status: Committed

Project Need:

The Heywood Interconnector Upgrade project will increase the capacity of the interconnector from a nominal 460 MW to 650 MW by the second half of 2016. 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 as is required by ElectraNet’s current day policies and standards. 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.

7.1.3 Pending projects

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

7.2 Transmission network development planning

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 (presented in this section) and resulting development plan 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 prepared according to the planning framework described in Appendix A. The transmission network development plan is based on forecasted 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 9.9% of their installed capacities, which reflects the 85% confidence interval for South Australian wind farm output during the top 10% of summer demand periods (refer to section 2.2).

Based on the 2015 NTNDP least cost generation expansion plan, there will be no new conventional generation plant built in South Australia within ten years. Substation fault levels were assessed (Appendix E) to ensure they will remain within design and equipment limits.

7.2.1 Planning scenarios

Three planning scenarios have been developed and evaluated as part of ElectraNet's planning process. These represent different assumptions about the future development of demand and generation in South Australia. The three scenarios are intended to represent a range of extreme, but credible, potential futures.[35]

The three planning scenarios are:

- Base scenario
- SA Mining Growth scenario
- SA Renewable Generation Expansion scenario.

Each planning scenario and related assumptions have been characterised (Table 7-3) and the potential new mining loads and generation connections are graphically represented (over the next 10 years, Figure 7-2). The adopted generation expansion forecast for each scenario can be compared to those used by AEMO in the 2015 NTNDP (Table 7-5).

[35] Note that these planning scenarios are not designed to correlate with the four future scenarios that are discussed in our December 2015 *Network Vision* discussion paper, available at electranet.com.au.

Table 7-3: Characteristics and assumptions of ElectraNet's three planning scenarios

Characteristic	Base	SA Mining Growth	SA Renewable Generation Expansion
Scenario description and purpose	This scenario is based on ElectraNet's central projections, and is our central planning scenario	This scenario considers a number of potential mining loads, incorporating general information from connection enquiries that is generalised for long-term planning When developing the network, ElectraNet considers including flexibility to meet future needs indicated by this scenario	This scenario represents an extreme yet possible expansion of SA wind generation, based on received connection enquiries which have been generalised for long-term planning It informs ElectraNet's consideration of projects that might be justified by potential net market benefits
Connection point maximum demand forecasts	ElectraNet's June 2015 connection point 10% POE medium forecast SA light load scenario projected from observed minimum demand on 26 December 2014	ElectraNet's June 2015 connection point 10% POE medium forecast, adjusted upwards by 10% in 2024–25 and by 20% in 2034–35.	ElectraNet's June 2015 connection point 10% POE medium forecast, adjusted downwards by 10% in 2024–25 and by 20% in 2034–35
SA transmission system coincident maximum demand forecast	AEMO's 2015 NEFR 10% POE forecast	AEMO's 2015 NEFR 10% POE forecast, adjusted upwards by 10% in 2024–25 and by 20% in 2034–35, plus the assumed direct-connect customer demand increases shown in Figure 7-2	AEMO's 2015 NEFR 10% POE forecast, adjusted downwards by 10% in 2024–25 and by 20% in 2034–35
Direct-connect customer demand increases	No new increases	As shown in Figure 7-2	No new increases
New or retired conventional generation plant	Maintain existing conventional generation fleet, with future power station closures and mothballings considered in line with AEMO's 2015 ESOO as far as possible	Expand thermal generation fleet to the minimum extent required to meet additional demand. New entrants are assumed to be in the Adelaide region, and are determined by a desktop study of conventional generation technologies most suitable to meeting new mining loads	Maintain existing conventional generation fleet, with future power station closures and mothballings considered in line with AEMO's 2015 ESOO as far as possible
New wind farm connections	As shown in Figure 7-2	No new wind farm connections	As shown in Figure 7-2
Generation dispatch	Assumptions guided by AEMO's 2015 ESOO and Gas Statement of Opportunities		
Embedded solar PV	Based on AEMO's embedded solar PV forecast at connection points		

Table 7-4: SA generator expansion forecasts by 2026–27

Scenario	South East (SESA)	Adelaide (ADE)	Northern South Australia (NSA)
Base	No change	Gas: -480 MW	Coal: -546 MW Wind: +570 MW
SA Mining Growth	No change	No change	Coal: -546 MW Wind: +570 MW
SA Generation Expansion	Wind: +375 MW	Gas: -480 MW Wind: +600 MW	Coal: -546 MW Wind/Large Scale Solar PV: +975 MW
2015 NTNDP (AEMO) "Gradual Evolution"	Coal: -546 MW Gas: -480 MW initially, then +201 MW Biomass: +50 MW Wind: +936 MW		
2015 NTNDP (AEMO) "Gradual Evolution Sensitivity"	Coal: -546 MW Gas: -480 MW initially, then +168 MW Biomass: +26 MW Wind: +500 MW Large Scale Solar PV: +800 MW		
2015 NTNDP (AEMO) "Rapid Transformation"	Coal: -546 MW Gas: -480 MW initially, then +57 MW Biomass: +50 MW Wind: +786 MW		
2015 NTNDP (AEMO) "Rapid Transformation Sensitivity"	Coal: -546 MW Gas: -480 MW Wind: +828 MW Large Scale Solar PV: +541 MW		

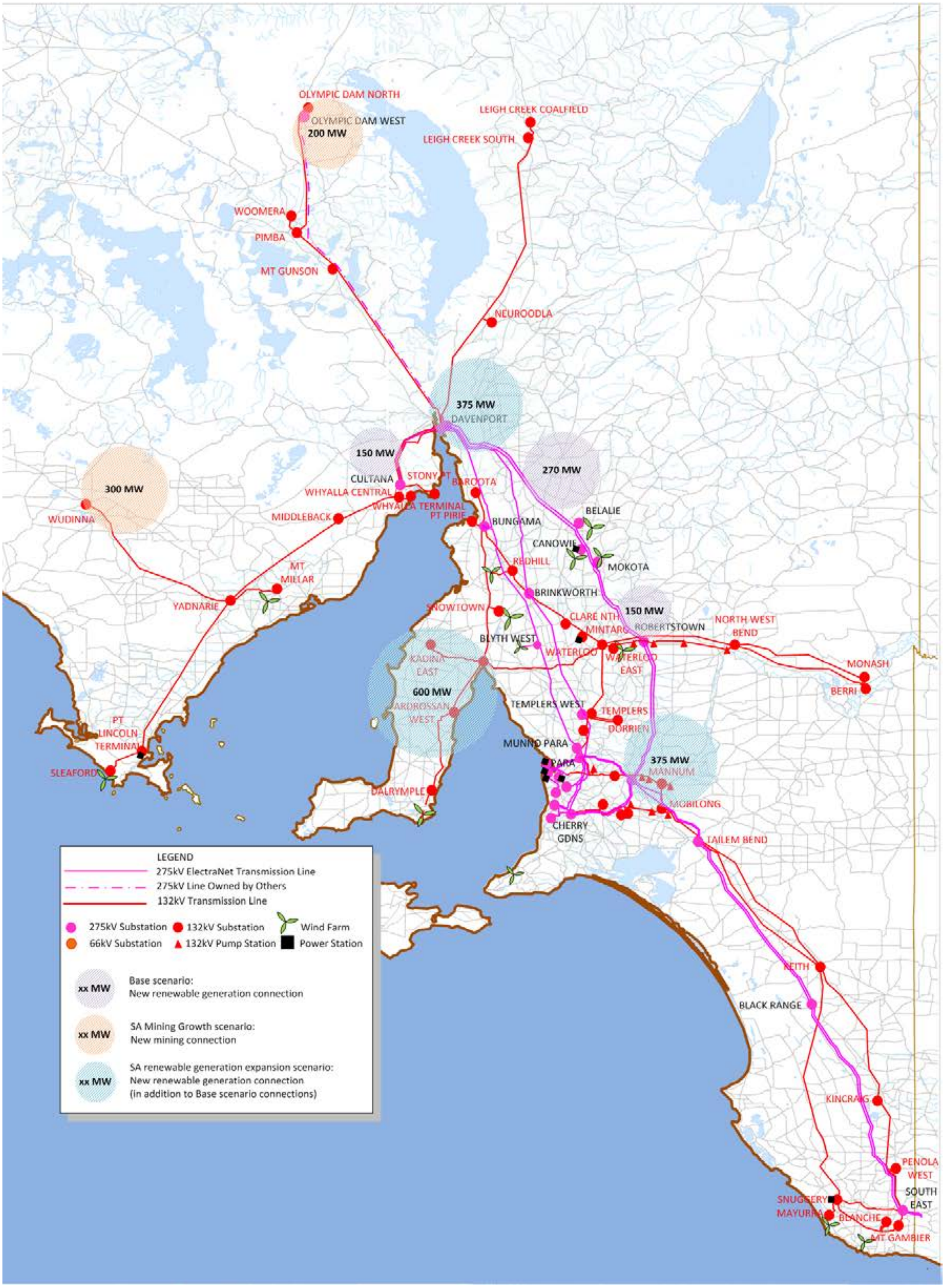

Figure 7-2: Potential future mining and renewable generation connections.

Note: The 270 MW base scenario renewable generation connection in the Mid North (between Belalie and Davenport) includes the 2016 Hornsdale wind farm connection.

7.2.2 Planning scenario analysis outcomes

Analysis of the planning scenarios led to a range of high level outcomes or project recommendations (Table 7-5). Detailed outcomes or potential projects required to support each scenario are also covered for the Base Scenario (section 7.2.3), SA Mining Growth scenario (7.2.4), and the SA Renewable Generation Expansion (section 7.2.5).

Table 7-5: Network reinforcement projects required (high level planning scenario outcomes) across ElectraNet's three planning scenarios

Scenario	Network reinforcement required (10-year planning outcomes)
Base	Install dynamic 275 kV reactive support at Davenport following the closure of Northern Power Station, as well as installation of 275 kV reactors to limit voltage rise at times of minimum demand Potential market benefits could be released with additional interconnector capacity
SA Mining Growth	Same as for the base scenario, as well as significant network augmentation in specific parts of the network, depending on actual mining developments driving this investment Potential market benefits could be released with additional interconnector capacity
SA Renewable Generation Expansion	Same as for the base scenario, as well as moderate network augmentation to avoid significant network congestion at maximum demand times At low demand times, wind generation output may be limited by the ability to export power from South Australia Potential market benefits could be released with additional interconnector capacity

Appendix G provides a comprehensive presentation of all of our proposed augmentation, security and compliance projects under each scenario. Sections 7.2.3 to 7.2.5 provide a more detailed summary of the significant projects that are needed in each scenario.

7.2.3 Base scenario – transmission network developments

As the base scenario informs ElectraNet's business plan, the following network reinforcement projects are proposed within the next ten years, in addition to existing committed (section 7.1.2) and pending (section 7.1.3) projects.

7.2.3.1 Uprate Upper South East 275 kV lines

Scope of work:	Uprate the Tailem Bend to Tungkillo 275 kV line and the Tailem Bend to Mobilong 132 kV line from 80°C design clearances to 100°C design clearances
Estimated cost:	<$5 million
Project category:	NCIPAP
Timing:	July 2016
Project status:	Committed

Project need and options analysis:

This project is in ElectraNet's NCIPAP for the 2015-2018 period. It will increase the transfer capacity of lines that are forecast to, at times, constrain the Heywood interconnector following its upgrade in July 2016, enabling higher transfers across the Tailem Bend to Tungkillo corridor by about 132 MVA. 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.

7.2.3.2 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

Project need and options analysis:

This project is in ElectraNet's NCIPAP for the 2015-2018 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.

7.2.3.3 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:	Committed

Project need and options analysis:

This project is in ElectraNet's NCIPAP for the 2015-2018 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.

7.2.3.4 Dynamic voltage control in northern South Australia

Scope of work:	Install dynamic reactive support at Davenport
Estimated cost:	Up to $60 million
Project category:	Security/compliance
Timing:	May 2019
Project status:	Proposed, RIT-T consultation imminent

Project need and options analysis:

ElectraNet has identified dynamic voltage control in South Australia's north as an emerging challenge (section 3.2.1). NPS ceased electricity generation on 9 May 2016.[36] As the NPS contributed to network voltage control service at the Davenport 275 kV substation, the withdrawal of NPS creates challenges for transmission network voltage control.

ElectraNet initiated system studies to identify potential network adequacy and security limitations resulting from the withdrawal of NPS. These studies revealed limitations under certain credible demand and generation scenarios (section 3.2.1) and ElectraNet has begun an options analysis (Table 7-6).

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

[36] Alinta Energy news announcement on 9 May 2016, available at: https://alintaenergy.com.au/about-us/news/augusta-power-station-ceases-generation

Table 7-6 Options considered for dynamic voltage control in northern South Australia

Option	Description	Comment	Estimated cost ($ Million)
1	Install two ±50-100 Mvar SVCs at Davenport	The scope and estimated cost of these network options will be refined during 2016	30–50
2	Install two ±50-100 Mvar Statcoms at Davenport		30–50
3	Install ±50-100 Mvar of small modular Statcoms and 50-100 Mvar of switched capacitors at Davenport		20–40
4	Install new ±50-100 Mvar synchronous condensers at Davenport		40-60
5	Convert Northern Power Station's generators for operation as synchronous condensers	This option could be offered by Alinta or another third party as a network support arrangement	TBA

7.2.3.5 Gawler East new connection point

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: TBA

Project category: Connection

Timing: November 2019

Project status: Proposed

Project need and options analysis:

The new Gawler East 132 kV connection point is planned to support new "greenfields type" residential development in the area. The residential 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 green fields 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 2019.

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) before the end of 2016.

A suitable ElectraNet 132 kV transmission line traverses the planned green fields residential development region and is better placed both environmentally (line already exists), and in terms of total cost to South Australian distribution customers (lower combined cost), to supply SA Power Networks' proposed 25 MVA 11 kV substation than the alternative of extending the existing SA Power Networks 66 kV network.

The preferred option will be determined by the outcome of the RIT-D assessment (Table 7-7).

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

Table 7-7 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	This option is expensive and is excluded from further consideration	16-34 (SA Power Networks)

7.2.3.6 Install one additional 275 kV switched reactor in the Mid North

Scope of work: Install a switched 50 Mvar 275 kV reactor in the Mid North

Estimated cost: Less than $5 million

Project category: Security/Compliance

Timing: August 2023

Project status: Proposed

Project need:

Studies have shown that after the provision of improved dynamic voltage control in northern South Australia by 2019 (section 7.2.3.4), steady-state voltage levels on the South Australian transmission system may breach 110% at times of low demand from 2023–24, following a single contingency event of an in-service generator. 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.

Initial studies indicate that installing this reactor at Templers West may optimise the benefit. A more detailed options analysis will be done closer to the time the project is needed.

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

7.2.4 SA Mining Growth scenario – transmission network developments

It is anticipated that most of the projects identified in planning for the Base scenario (section 7.2) will also be needed under the SA Mining Growth scenario. A possible exception is the project to install an additional 275 kV switched reactor (section 7.2.3.6), which may be able to be deferred if a significant new base load is connected. Two additional significant network augmentation projects would be required under the SA Mining Growth planning scenario, potentially within the next ten years.

A major reinforcement of the Main Grid between Adelaide and Davenport would be needed if all of the potential major mining developments that are considered in this scenario proceed. Alternatively, the large demand that this scenario indicates in the regions supplied by Davenport may once more make it attractive for new major baseload generation to connect at or near Davenport.

7.2.4.1 Lower Eyre Peninsula major reinforcement

Scope of work:	Construct a new double circuit 275 kV 600 MVA transmission line (strung only on one side) between Cultana and Yadnarie, and establish a new Yadnarie West 275/132 kV substation with one 200 MVA transformer. New load to be supplied via 275 kV and 132 kV connections at Yadnarie.
Estimated cost:	$150–300 million
Project category:	Augmentation
Timing:	Within ten years
Project status:	Proposed, subject to customer connection; project assessment draft report (PADR) issued in 2013 but RIT-T currently on-hold

Project need:

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

In January 2013, ElectraNet published a PADR as the second stage of the RIT-T consultation process regarding options for reinforcement of the Lower Eyre Peninsula transmission network. The PADR and non-confidential submissions from interested parties on the report are available on ElectraNet's website.[37]

ElectraNet is in on-going discussions with a number of potential connection applicants in relation to spot-load developments. The commitment of new spot loads (e.g. mining loads) in the region will drive the nature and timing of the network reinforcement. Alternatively, poor conductor condition on the existing Eyre Peninsula 132 kV lines could accelerate the need for line reinforcement (section 7.3.4).

The Eyre Peninsula transmission network could be suitably configured to supply increased demand under this planning scenario (Figure 7-3).

[37] electranet.com.au

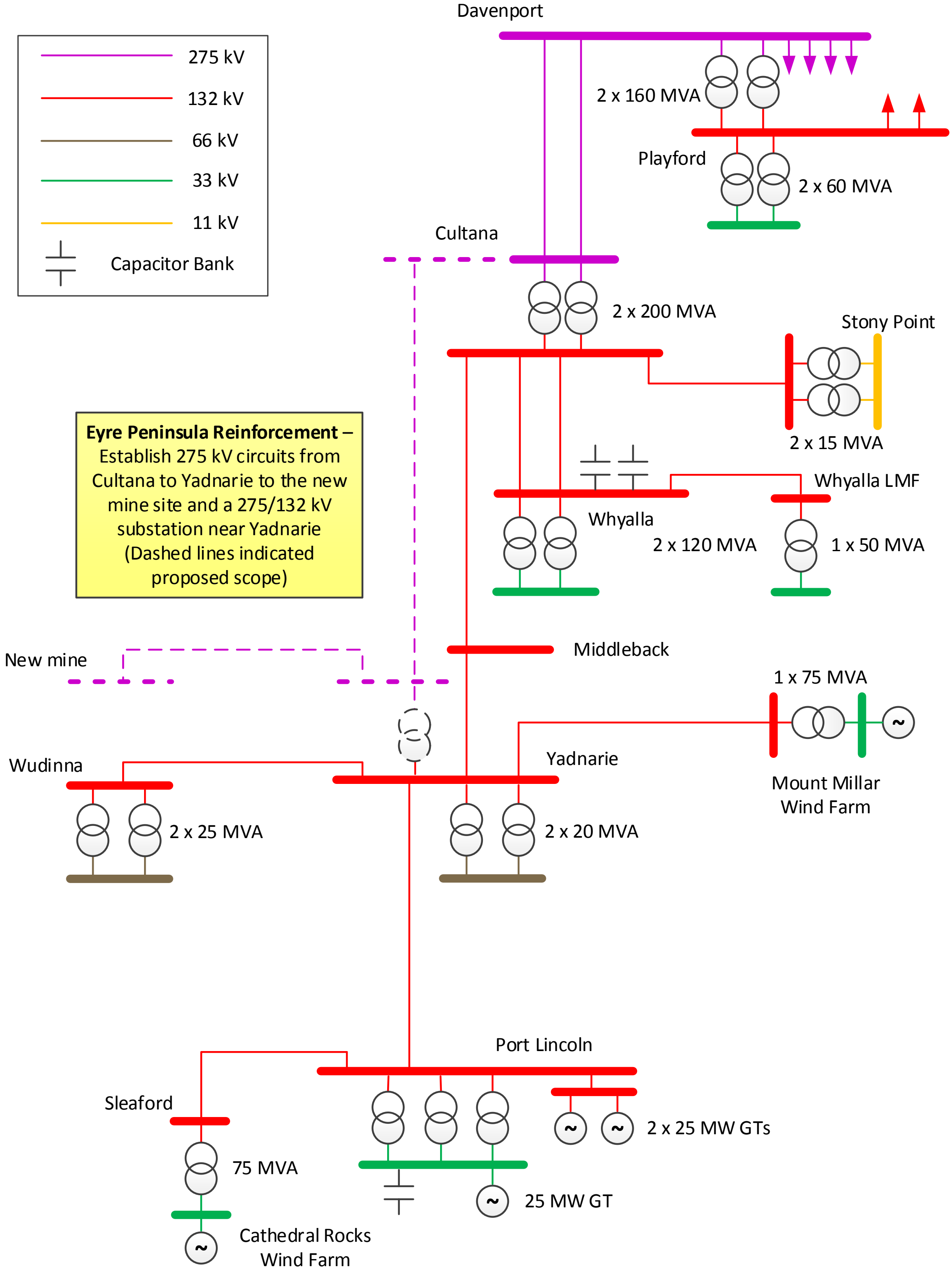

Figure 7-3: Eyre Peninsula transmission network single line diagram: SA Mining Growth scenario

7.2.5 SA renewable generation expansion scenario – transmission network developments

It is anticipated that all of the projects identified in planning for the Base scenario (section 7.2.3) will also be needed under the SA Renewable Generation Expansion scenario. The proposed security/compliance projects to install additional 275 kV switched reactors (sections 7.2.3.2 and 7.2.3.4) may be needed earlier than in the Base scenario. Six additional network augmentation projects would be needed under the SA Renewable Generation Expansion scenario to potentially avoid significant congestion at peak demand times on the South Australian transmission network, if implemented within the next ten years.

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

ElectraNet is currently examining the potential economic benefit of establishing a new large interconnector, possibly from the northern region of South Australia to either the New South Wales or Victorian transmission networks. This would significantly increase South Australia's ability to import and export power and would reduce its reliance on the existing Heywood HVAC interconnector. Refer to section 3.2.2 for more details.

7.2.5.1 Apply dynamic line ratings to the Davenport to Robertstown 275 kV lines

Scope of work:	Remove various plant limits (e.g. remove line traps, replace current transformers, and change current transformer ratios) at Robertstown, Canowie, Davenport and Mokota and apply dynamic line ratings to both 275 kV circuits between Robertstown and Davenport.
Estimated cost:	Less than $5 million
Project category:	To be considered for inclusion in 2018 – 2023 NCIPAP
Timing:	Within ten years
Project status:	Subject to demonstration of net market benefits

Project need:

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

If this scenario eventuates, we propose to address various plant rating limits and apply dynamic ratings to these lines. This work would increase the capacity of the lines, especially at times of high wind generation. It would also significantly increase line capacity at times of high power flows and help avoid serious congestion.

7.2.5.2 Increase the Robertstown 275/132 kV transformers' rating

Scope of work: Remove various plant limits (e.g. change current transformer ratios) and apply short term loading limits to the Robertstown 275/132 kV transformers.

Estimated cost: Less than $5 million

Project category: To be considered for inclusion in 2018 – 2023 NCIPAP

Timing: Within ten years

Project status: Subject to demonstration of net market benefit

Project need:

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

7.2.5.3 Mid North 132 kV control scheme

Scope of work: Implement a control scheme to reconfigure the Mid North 132 kV network at times of high wind generation to reduce the occurrence of constraints on 132 kV lines.

Estimated cost: Less than $5 million

Project category: To be considered for inclusion in 2018 – 2023 NCIPAP

Timing: Within ten years

Project status: Subject to demonstration of net market benefit

Project need:

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

7.2.5.4 Apply dynamic line ratings on the Tungkillo to Heywood 275 kV corridor

Scope of work: Remove various plant limits (e.g. replace current transformers, change current transformer ratios) and work with AusNet Services to apply dynamic ratings to 275 kV lines in the Tungkillo to Heywood corridor.

Estimated cost: Less than $5 million

Project category: To be considered for inclusion in 2018 – 2023 NCIPAP

Timing: Within ten years

Project status: Subject to demonstration of net market benefit

Project need:

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

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

7.2.5.5 String vacant circuit, Tungkillo to Tailem Bend 275 kV circuit and install dynamic reactive support at Tailem Bend

Scope of work: String the vacant circuit between Tailem Bend and Tungkillo 275 kV and install dynamic reactive support at Tailem Bend

Estimated cost: $25–50 million

Project category: Market benefit

Timing: Within ten years

Project status: Subject to demonstration of net market benefit

Project need:

Increased congestion is expected on the Tungkillo to South East 275 kV corridor during high export conditions. Depending on the location of wind farms, adding additional thermal capacity in this corridor would increase the export capacity of the Heywood interconnector.

New dynamic reactive support (such as an SVC) would be needed at Tailem Bend to increase voltage and oscillatory limits to a similar level to the increased rating of the corridor.

7.2.5.6 Install reactive support at Monash

Scope of work: Install two 15 Mvar capacitors at Monash

Estimated cost: $5–8 million

Project category: Market benefit

Timing: Within ten years

Project status: Subject to demonstration of net market benefit

Project need:

Low voltage levels on the Riverland 132 kV network may limit the ability to increase export transfers across the Murraylink interconnector. This may limit South Australian export transfer levels at times of high wind farm output. The installation of up to two 15 Mvar 132 kV capacitors at Monash would improve 132 kV voltage levels on the Riverland 132 kV network during times of high power transfer, and support greater available exports across the Murraylink interconnector.

7.3 Projects being considered for contingent status

ElectraNet is currently considering a range of projects that may be submitted as contingent projects in our 2018-23 revenue proposal. The list of projects, along with their triggers and proposed scopes, will be refined in the second half of 2016. The projects that are currently being considered are listed in Appendix G.

7.4 Replacement and refurbishment projects

ElectraNet performs a planning assessment when a significant investment at a single site would be required to replace or refurbish assets, and has recently completed a planning assessment for four sites: Leigh Creek (section 7.3.1), Mount Barker (section 7.3.2), Mount Gambier (section 7.3.3), and the Eyre Peninsula 132 kV lines (section 7.3.4).

Many projects in ElectraNet's capital program are planned based on asset condition. When asset condition monitoring indicates that an asset is at the end of its life, ElectraNet assesses whether the most economical solution is to replace the asset or find an alternate solution. Where possible, replacement projects are timed with augmentation projects to minimise unnecessary mobilisation and overhead costs.

Appendix G includes a comprehensive presentation of our proposed replacement and refurbishment projects. Sections 7.3.1 to 7.3.4 provide a more detailed summary of the asset replacement and refurbishment needs that we have subjected to a detailed planning analysis.

7.4.1 Leigh Creek Coalfield and Leigh Creek South 132/33 kV connection point reconfiguration

Scope of work:	Reconfigure Leigh Creek Coalfield and Leigh Creek South substations by placing one transformer into hot standby at each site
Estimated cost:	Less than $1 million
Project category:	N/A (operational expenditure only)
Timing:	2016
Project status:	Committed

Project need and options analysis:

ElectraNet proposed to replace the 10 MVA 132/33 kV transformers in the 2018–23 period at both Leigh Creek South and Leigh Creek Coalfield (two at each site) in the 2015 Transmission Annual Planning Report. Alinta has since announced and implemented the closure of the coal mine at Leigh Creek. ElectraNet has analysed potential options to address asset condition at each of these sites (Table 7-8).

Table 7-8: Leigh Creek Coalfield and Leigh Creek South 132/33 kV connection point reconfiguration – options considered

Option	Description	Comments	Estimated cost ($M)
1	Switching reconfiguration	Placing one transformer on hot-standby[38] in each site will immediately mitigate the risk of failure and permanent damage to the 132/33 kV transformers at Leigh Creek South and Leigh Creek Coalfield substations. If the in-service transformer is damaged by a fault event, then the standby transformer would be unaffected and can be switched into service. Implementing this option provides an opportunity to monitor the future demands at both Leigh Creek Coalfield and Leigh Creek South, so that a solution can be designed that will fit the remaining actual demand.	<1
2	Replace transformers	Installing a new unit in each site will address the risk of the transformers in poor condition at Leigh Creek South and Leigh Creek Coalfield.	3–5
3	Micro grid and decommission 132 kV line	Decommissioning the transformers and establishing a micro-grid comprising of a mix of standby diesel generators, wind generator, solar PV, battery storage and their associated control systems will address the associated risk of the transformers in poor condition at Leigh Creek South and Leigh Creek Coalfield. This also includes converting and operating the Leigh Creek South – Leigh Creek Coalfield 132 kV line to 33 kV to maintain supply to the coalfield (if needed). ElectraNet will monitor any reduction in demand at the Leigh Creek sites, which will improve the viability of this option.	15–25
4	Micro grid and de-energise 132 kV line	This option is the same as option 3 but the Neuroodla-Leigh Creek Coalfield 132 kV line would be de-energised instead of decommissioned. ElectraNet will monitor any reduction in demand at the Leigh Creek sites, which will improve the viability of this option.	10–20

[38] Keep the transformer connected on the 132 kV side (supply side), but disconnect it on the 33 kV side (load side) – transformer can then be manually returned to service if the in-service transformer fails.

7.4.2 Mount Barker 132/66 kV connection point asset replacements

Scope of work: Replace assets at Mount Barker substation that are in poor condition

Estimated cost: Less than $3 million

Project category: Replacement

Timing: 2018–23

Project status: Proposed

Project need and option analysis:

ElectraNet has analysed options to address asset condition at each of the Mount Barker connection points (Table 7-9). Options 2 and 3 would shift all demand from the Mount Barker 132/66 kV connection point to the Mount Barker South 275/66 kV connection point, which would alleviate limits on the Eastern Hills 132 kV network that can at times constrain transfers on the Heywood interconnector.

Table 7-9: Mount Barker 132/66 kV connection point asset replacements – options considered

Option	Description	Comments	Estimated cost ($M)
1	Refurbish Mount Barker substation.	Replacing assets in poor condition will address this requirement, and is the preferred option.	<3
2	Install second Mount Barker South 275/66 kV transformer.	Decommissioning the site and installing a second Mount Barker South 275/66 kV transformer will address the requirement to replace assets at Mount Barker substation. Circuit continuity of the 132 kV line would be established by reconnecting using the two gantry structures inside the Mount Barker substation. Modelled benefits from alleviated interconnector constraints are insufficient to bridge the gap between this and option 1; however, ElectraNet will reassess the viability of this option if the scope and cost of this option can be reduced and if the modelled market benefits improve.	10–20
3	Install second Mount Barker South 275/66 kV transformer and construct 132 kV line.	Decommissioning the site and installing a second Mount Barker South 275/66 kV transformer will address the requirement to replace assets at Mount Barker substation. Circuit continuity of the 132 kV line would be established by constructing a 132 kV line outside of the Mount Barker substation. Modelled benefits from alleviated interconnector constraints are insufficient to bridge the gap between this and option 1; however, ElectraNet will reassess the viability of this option if the scope and cost of this option can be reduced and if the modelled market benefits improve.	10–20

7.4.3 Mount Gambier 132/33 kV transformer replacement

Scope of work: Replace the 50 MVA 132/33 kV transformer No. 1 at Mount Gambier with a 25 MVA 132/33 kV transformer

Estimated cost: $3–5 million

Project category: Replacement

Timing: 2018–23

Project status: Proposed

Project need and options analysis:

The existing 50 MVA 132/33 kV transformer at Mount Gambier is in poor condition. Replacing the transformer with a 25 MVA transformer will provide sufficient capacity to meet the connection point's category 4 reliability standard (Table 7-10).

Table 7-10: Mount Gambier 132/33 kV transformer replacement – options considered

Option	Description	Comments	Estimated cost ($M)
1	Replace the transformer with a new 25 MVA 132/33 kV transformer.	Replacing the existing unit with a new transformer will address the requirement to replace the transformer in poor condition at Mount Gambier substation.	3–5
2	Decommission Mount Gambier 50 MVA transformer and mesh 33 kV distribution network with the network supplied from Blanche.	Decommissioning the transformer and meshing the Mount Gambier 33 kV distribution network with the adjacent Blanche 33 kV network will address the requirement to replace the transformer in poor condition at Mount Gambier substation.	20–25
3	Decommission Mount Gambier substation and transfer load.	Decommissioning Mount Gambier substation and transferring the entire Mount Gambier load to Blanche through the 33 kV distribution network will address the requirement to replace the transformer in poor condition at Mount Gambier substation.	23–28
4	Rebuild Mount Gambier substation on a new site with 2 x 25 MVA 132/33 kV TFs.	Decommissioning Mount Gambier substation and rebuilding the connection point on a new site (land has already been purchased) will address the requirement to replace the transformer in poor condition at Mount Gambier substation.	30–40

7.4.4 Eyre Peninsula 132 kV line replacement

Scope of work: Build new double circuit 132 kV lines from Cultana to Yadnarie and from Yadnarie to Port Lincoln

Estimated cost: $100-150 million

Project category: Augmentation (Replacement trigger)

Timing: 2020

Project status: Proposed

Project need and option analysis:

ElectraNet has assessed that 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. ElectraNet has analysed options to address this need (Table 7-11). Options 4 and 5 would directly address the identified need by rebuilding the relevant line sections, whereas options 1, 2 and 3 would provide additional capacity, reliability and market benefits and would need to pass a RIT-T to be implemented.

Preliminary assessment shows that option 1 produces net market benefits.

A RIT-T to address this need would also consider the future needs of potential new mining loads on the Eyre Peninsula (section 7.2.4.1) in the scenario analysis.

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

Table 7-11: Eyre Peninsula 132 kV lines replacement – options considered

Option	Description	Comments	Estimated cost ($M)
1	Build new double circuit 132 kV lines from Cultana to Port Lincoln via Yadnarie	This option would also increase reliability to Yadnarie, Wudinna, and Port Lincoln connection points, and reduce constraints on Eyre Peninsula wind generation	100-150
2	Build new double circuit 275 kV lines from Cultana to Port Lincoln via Yadnarie	This option would also increase reliability to Yadnarie, Wudinna, and Port Lincoln connection points, and reduce constraints on Eyre Peninsula wind generation	200-400
3	Build new double circuit 132 kV lines from Cultana to Port Lincoln via Yadnarie in two stages (2020 and 2025)	This option would also increase reliability to Yadnarie, Wudinna, and Port Lincoln connection points, and reduce constraints on Eyre Peninsula wind generation, but the full benefits would only apply after 2025	100-150
4	Reconductor four 15-30 km 132 kV line sections	Assumed costs for generation support have been included, to allow the work to be performed with the lines de-energised	50-80
5	Reconductor four 15-30 km 132 kV line sections using live-line methods	Using live-line methods will increase the cost of the work, but this will be offset by reducing the need for generation support	40-70

South Australian Transmission Annual Planning Report

Appendices

June 2016

Security Classification: Public

Appendix A Transmission planning framework

A1 South Australian electricity market framework

A1.1 Australian Energy Market Operator

AEMO has the responsibility of national transmission planner conferred on it under the national electricity law. The South Australian Energy Minister has also requested AEMO perform certain additional functions in the South Australian jurisdiction.

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

- 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.

Until 2012, AEMO provided the above information in the South Australian Supply and Demand Outlook. Since 2012, a collection of advisory reports for South Australia have been released during each year (available on AEMO's South Australian Advisory Functions[39] webpage), and in the NTNDP which is published annually in December.

A1.2 Essential Services Commission of South Australia

ESCOSA was established under the *Essential Services Commission Act 2002* to provide 'protection of the long term interests of South Australian consumers with respect to the price, quality and reliability of essential service'. ESCOSA is required to attend to the:

- promotion of competitive and fair market conduct
- prevention of misuse of monopoly or market power
- facilitation of entry into relevant markets
- promotion of economic efficiency
- benefit consumers gain from competition and efficiency
- financial viability of regulated industries and the incentive for long term investment

[39] Available at http://www.aemo.com.au/Electricity/Planning/South-Australian-Advisory-Functions

- promotion of consistency in regulation with other jurisdictions[40].

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

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

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/energy-rules/national-electricity-rules/current-rules.

At the time of publication, the current version of the Rules is Version 81.

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

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 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 2016 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 2010. The RIT-T is designed to deliver solutions to identified network limitations that maximise the present value of net economic benefits to all those who produce, consume and transport electricity in the NEM. Solutions to network limitations may include both network and non-network options.

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

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

The RIT-T took effect on 1 August 2010 and assesses the costs and market benefits of transmission investments with the solution delivering the highest benefit on a net present value basis being deemed to pass the test.[41]

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

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

electranet.com.au. Projects which have recently completed the RIT-T but are not yet fully committed are presented in section 7.

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

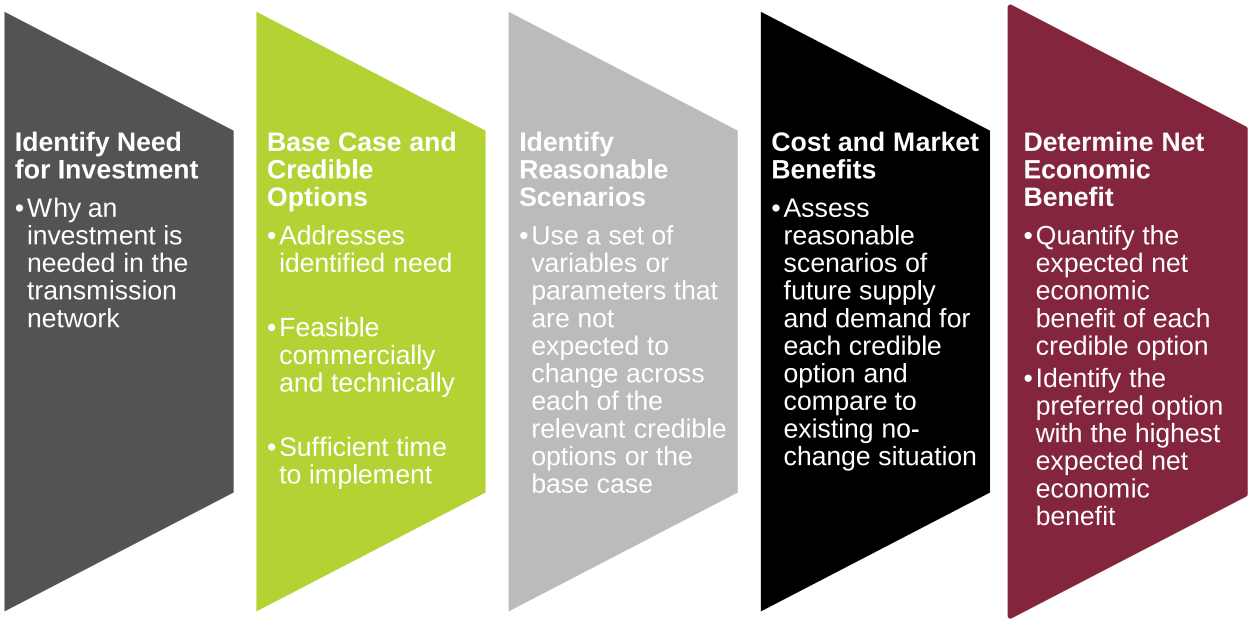

Figure A-1: ElectraNet's approach to the Regulatory Investment Test for Transmission (RIT-T) process

A3 ElectraNet's responsibilities under the 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 effective from 1 July 2013 (Table A-1).[42] In October 2015, ESCOSA began a major review of the ETC. The purpose of the review is to set the transmission reliability standards and other requirements so that ElectraNet can develop its planned capital and operating costs, to be incorporated into its regulatory business proposal to be submitted to the AER for its next revenue determination. In March 2016, ESCOSA published a draft determination[43] for a revision of the ETC that is intended to apply for ElectraNet's 2018–23 regulatory control period. The draft determination was open for public consultation until Friday 20 May 2016. ESCOSA will now make a final determination on the reliability standards and other requirements to be included in the ETC from July 2018.

The key draft decisions are proposals to:

- not increase the reliability requirements for any exit points in the transmission system over the five-year period starting July 2018
- conduct further reviews of specific exit points, potentially to reduce the reliability requirements for those exit points if it is economic to do so at that time, when equipment at those points requires replacement
- require ElectraNet to provide updated economic analysis on capital investment decisions for projects that are required to meet Code requirements prior to making a commitment to proceed with those projects (whether for maintenance or for upgrade of capacity). This will provide a second 'check point' prior to investment decisions proceeding, to ensure that the assumptions underpinning the standards set in the code in advance of the 2018 regulatory period can be re-assessed for currency at the relevant time. This is particularly important given the economic and structural changes now facing the electricity supply industry
- clarify that the Code's requirements are outcomes-based. That is, they are technology neutral and do not require or mandate the use or deployment of specific types of plant and equipment; rather, they mandate service outcomes from exit points and provide ElectraNet with the flexibility as to how the standards are met (e.g. generation capacity, demand management, battery storage or other means). This is particularly the case given that more traditional means (plant and equipment) of meeting the standards may (at a future time) no longer be the most efficient due to the evolution of disruptive technologies.

[42] Available at http://www.escosa.sa.gov.au/library/130701-ElectricityTransmissionCode-TC07_2.pdf.
[43] Available at http://www.escosa.sa.gov.au/Publications/DownloadPublication.aspx?id=3339&versionId=3553.

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 65% of 'N' standard
Restoration time to 'N-1' standard after outage	N/A		As soon as practicable - best endeavours		
Transformer capacity					
'N' capacity	100% of 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 65% of 'N' standard
Restoration time to 'N-1' standard after outage	N/A		As soon as practicable – best endeavours		
Spare transformer requirement	Sufficient spares of each type to meet standards in the event of a failure				
Allowed period to comply with required contingency standard following a change in forecast AMD that causes the specific OFGSreliability 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).

A4 ElectraNet planning framework

A4.1 Network planning approach

ElectraNet's approach to transmission network planning is driven by regulatory arrangements under the Rules and ETC. The Rules and ETC regulatory arrangements shape key inputs to the network planning process, including demand forecasts and network planning criteria and assumptions. Key outputs from the network planning process include this *2016 Transmission Annual Planning Report* and reports published in accordance with the requirements of the Regulatory Investment Test for Transmission (RIT-T) as discussed in section A2.2.

A4.2 Planning assumptions

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

A4.3 Technical criteria

Generator dispatch assumptions

ElectraNet considers a range of system conditions for planning studies (Table A-2). These study conditions provide an overview of the capability of the South Australian transmission system over a range of extreme, but realistic, operating conditions.

Table A-2: Demand and generator dispatch conditions that ElectraNet considers when planning the transmission system

System condition	SA system demand	Wind farm output	Interconnector transfer
High demand, low wind	As per AEMO's NEFR 10% PoE maximum demand forecast	9.9%	Maximum import
High demand, high wind	As per AEMO's NEFR 10% PoE maximum demand forecast	75%	Moderate import
Moderate demand, low wind	~1,400 MW	9.9%	Maximum import
Moderate demand, very high wind	~1,400 MW	90%	Low export
Low demand, low wind	As per AEMO's NEFR 90% PoE minimum demand forecast	9.9%	Initially 0 MW, with export rising as minimum demand decreases
Low demand, moderate wind	As per AEMO's NEFR 90% PoE minimum demand forecast	Maximum that can be accommodated by SA export capability	Maximum export

When ElectraNet assesses the capacity of the transmission system's radial parts, we also consider circumstances where no wind power is available from the wind farms that can affect the net loading on the radial network.

ElectraNet also considers other system conditions when they are appropriate for specific planning studies.

Overhead line ratings

ElectraNet applies transmission line ratings that have been determined to ensure statutory conductor to ground clearances is maintained at all times. As the rating of overhead lines is dependent upon the environmental conditions, ElectraNet uses ambient temperature dependent ratings which are generally translated into three seasonal ratings (summer, spring/autumn and winter).

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

Transformer ratings

ElectraNet applies ratings to transformers in accordance with Australian Standards. Where specifications of the transformers do not allow cyclic ratings, nameplate ratings are applied. However, in cases where the original specification or subsequent assessment allows, transformers are given a cyclic rating above nameplate in accordance with *Australian Standard AS 60076.7-2013*.

The following criteria are adopted for the purposes of planning.

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

ElectraNet applies short term ratings to transformers where it is technically viable and where it will release additional transmission capacity and reduce the occurrence of network and interconnection constraints. These ratings take the form of a short term emergency loading, which can be sustained for up to 30 minutes, and a long term emergency loading, which can be sustained for up to three hours.

Cable ratings

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

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

Managing fault levels

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

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

Reactive power reserve margins

ElectraNet assesses reactive power margin at all connection points in accordance with the provisions of the voltage control criterion as specified in schedule 5.1.8 of the Rules. In applying this Rules requirement, ElectraNet deems the maximum fault level (in MVA) at the connection point as the maximum three-phase fault level that is reasonably expected. This includes the effect of local and embedded conventional generation, but with wind farm generator output set to zero.

ElectraNet assesses the adequacy of reactive power margin over two timescales.

1. The first 15–30 seconds following a critical contingency event, before transformer automatic on-load tap changers begin to respond. For this time period, ElectraNet applies a small voltage-dependent characteristic to the reactive power component of demand.
2. A longer period representing the final state of the system following a critical contingency event, after transformer automatic on-load tap changers have responded to restore voltage. For this time period, ElectraNet applies a load characteristic that is independent of voltage.

Stability criteria

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

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

- the transmission system will remain in synchronism (transient stability)
- damping of the system oscillations will be adequate (small signal stability)
- network voltage criteria will be satisfied (voltage stability)
- system frequency will remain within defined operating limits (frequency stability).

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

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

Appendix B Compliance checklist

This section sets out a compliance checklist which demonstrates the compliance of ElectraNet's 2015 Transmission Annual Planning Report with the requirements of clause 5.12.2(c) of version 80 of the Rules.

Summary of requirements	Section
The Transmission Annual Planning Report must set out:	
(1) the forecast loads submitted by a Distribution Network Service Provider in accordance with clause 5.11.1 or as modified in accordance with clause 5.11.1(d);	Chapter 5, and the *2016 South Australian Connection Point Forecasts Report*[44]
(2) planning proposals for future connection points;	Table 6-3
(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;	Sections 7.2 and 7.3
(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;	Appendix F
(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	Sections 7.2.3, 7.2.4, 7.2.5 and Appendix G

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

Summary of requirements	Section
(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;	
(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
(7) for all proposed replacement transmission network assets: (i) a brief description of the new replacement transmission network asset project, including location; (ii) the date from which the Transmission Network Service Provider proposes that the proposed new replacement transmission network asset will become operational; (iii) the purpose of the proposed new replacement transmission network asset; (iv) a list of any reasonable network options or non-network options to the proposed new replacement transmission network asset which are being, or have been, considered by the Transmission Network Service Provider (if any). Those alternatives include, but are not limited to, interconnectors, generation options, demand side options, market network service options and options involving other transmission or distribution networks; and (v) the Transmission Network Service Provider's estimated total capitalised expenditure on the proposed new replacement transmission network asset; and	Section 7.4 and Appendix G
(8) any information required to be included in an Transmission Annual Planning Report under clause 5.16.3(c) in relation to a network investment which is determined to be required to address an urgent and unforeseen network issue	Not Applicable

Appendix C Regional networks

ElectraNet's Main Grid (Figure 2-2) is connected to seven regional networks and two interconnectors of varying transfer capability (section 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.

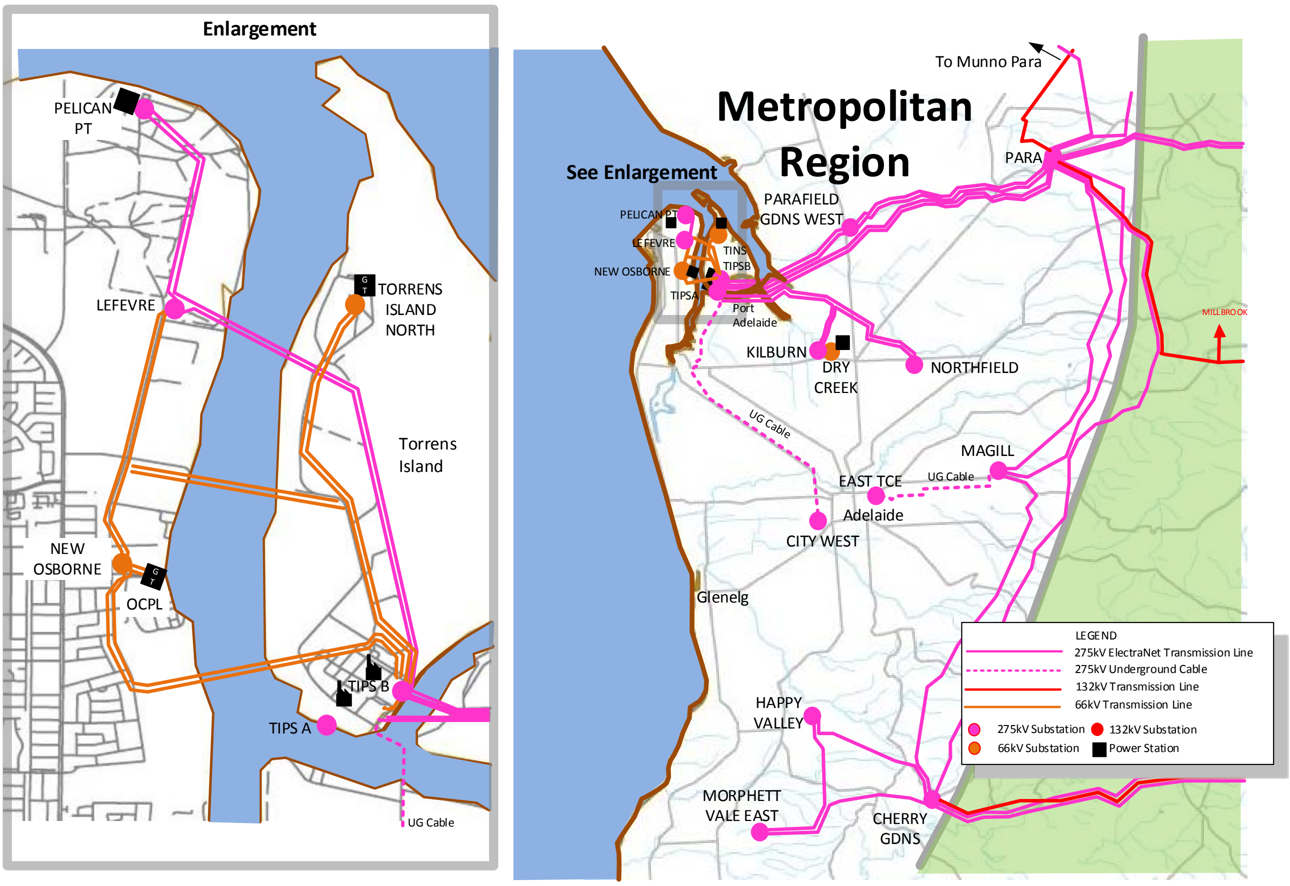

Figure C-1: Metropolitan transmission network and supply region

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.

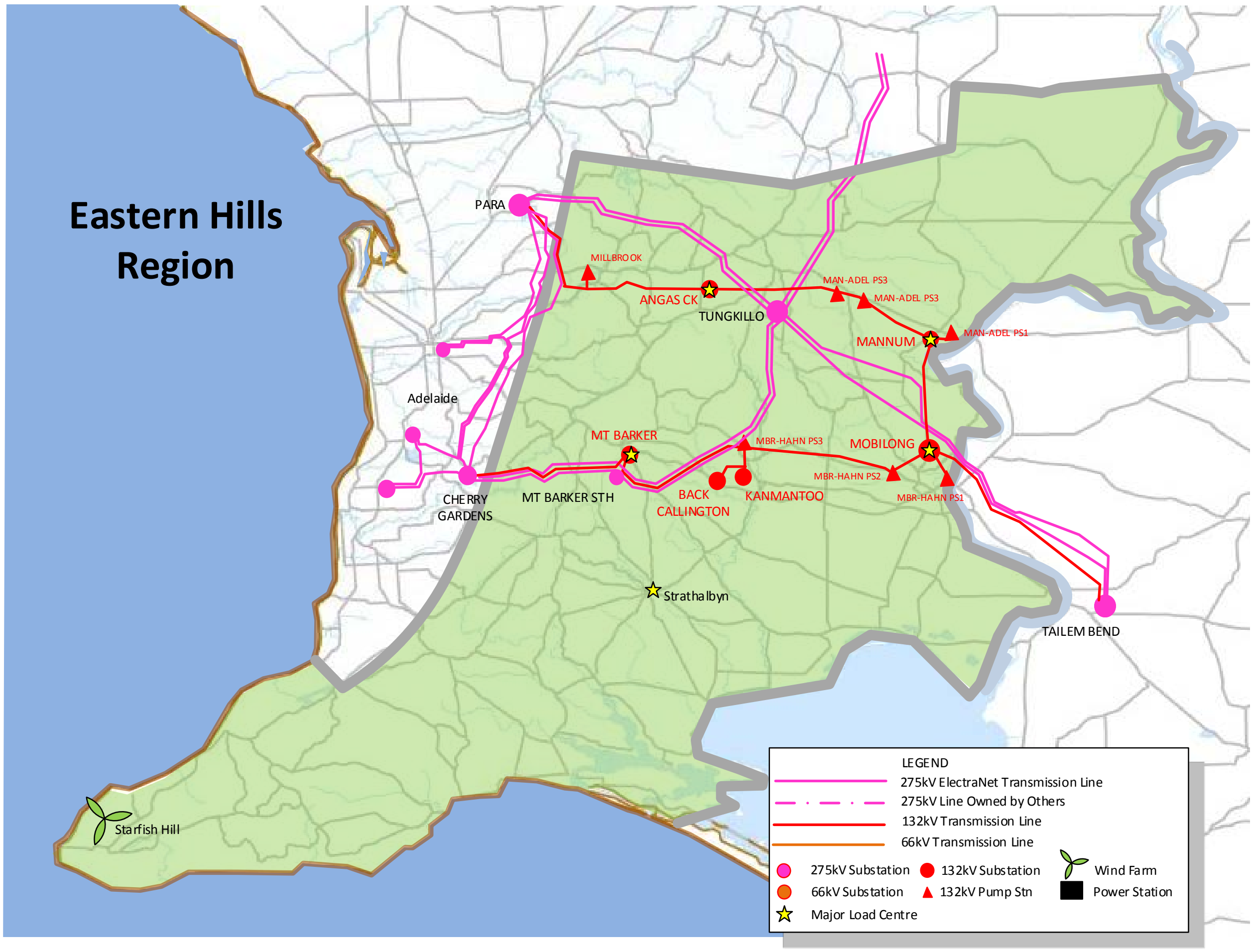

Figure C-2: Eastern Hills transmission network and supply region

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.

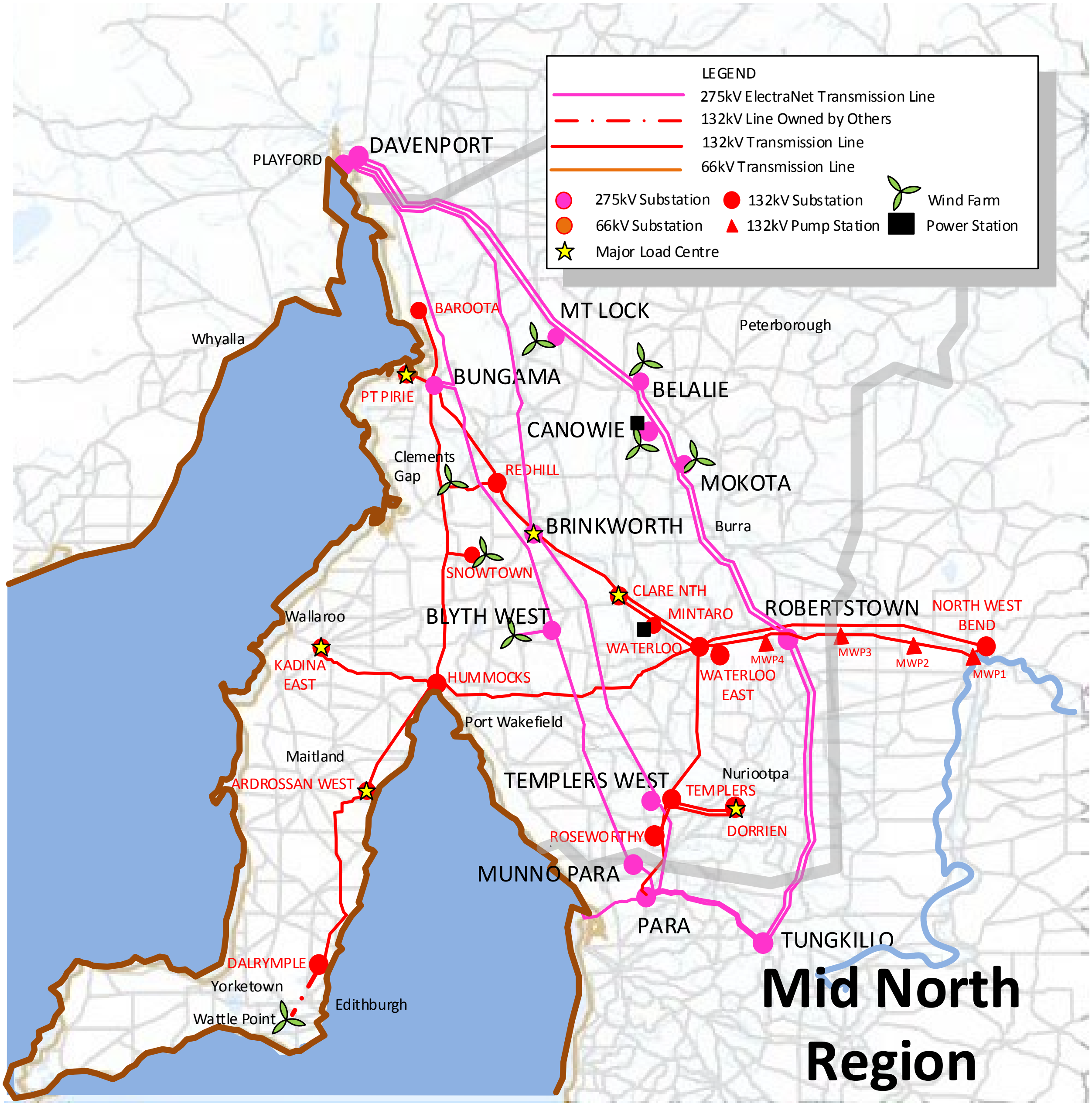

Figure C-3: Mid North transmission network and supply region

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.

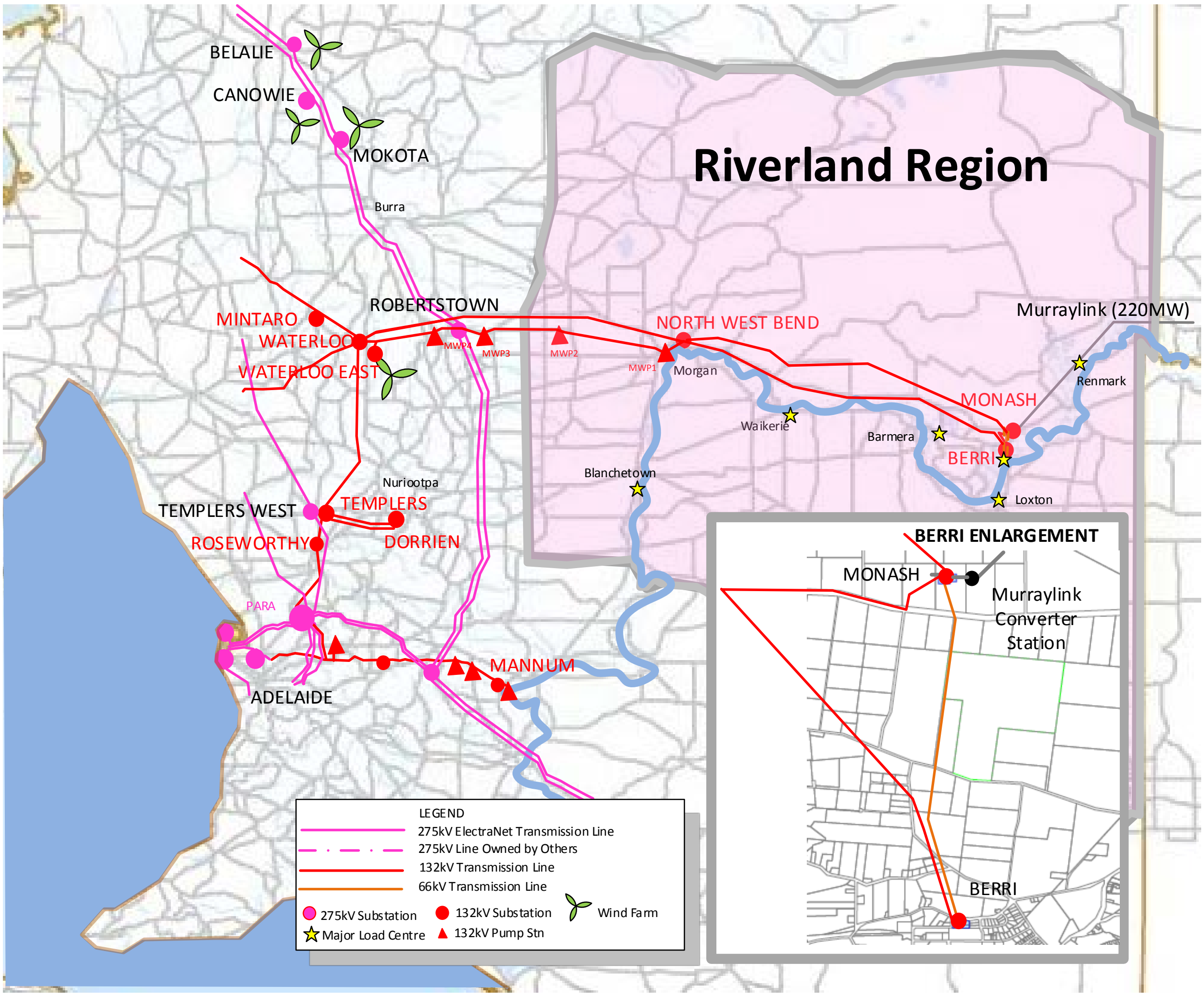

Figure C-4: **Riverland transmission network and supply region**

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.

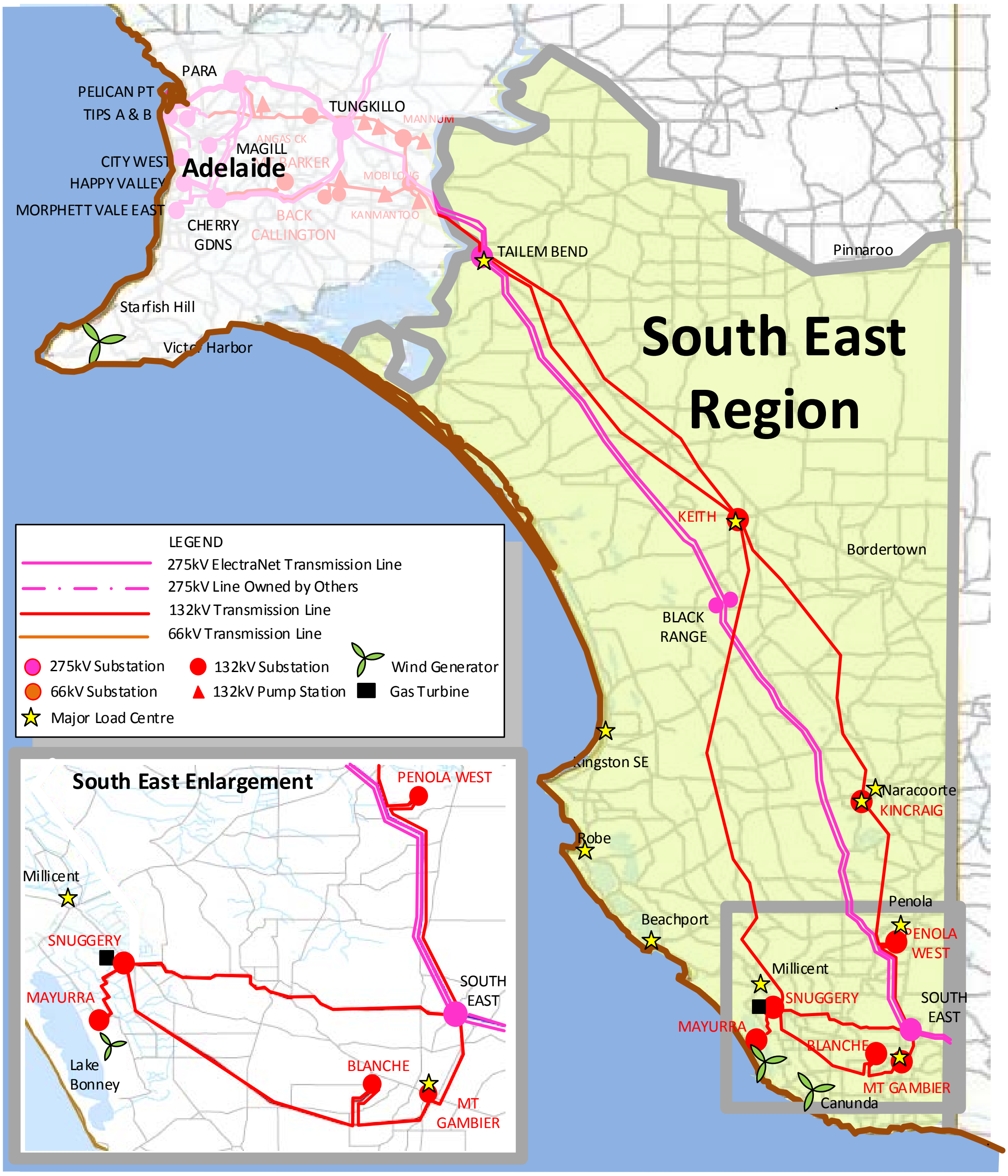

Figure C-5: **South East transmission network and supply region**

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.

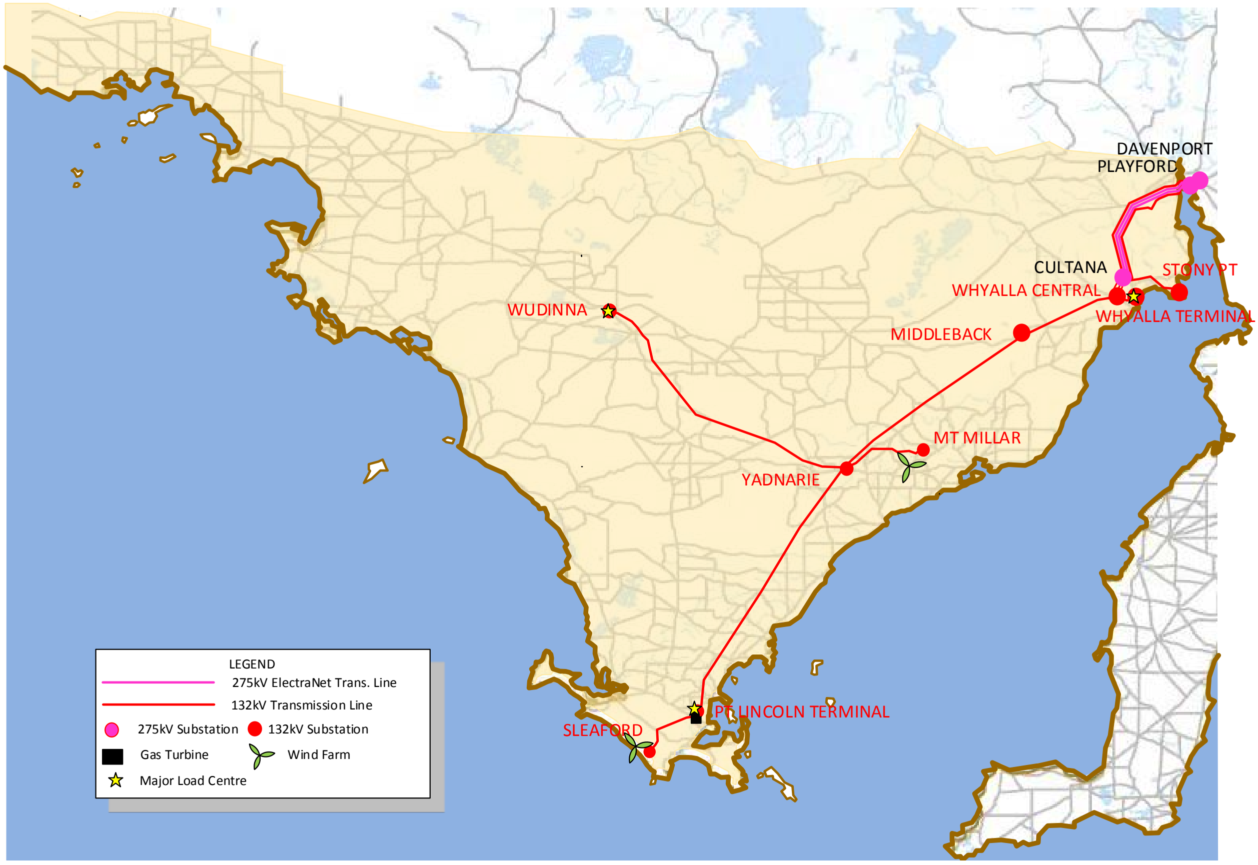

Figure C-6: Eyre Peninsula transmission network and supply region

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–Pimba 132 kV line and the Davenport-Olympic Dam 275 kV line.

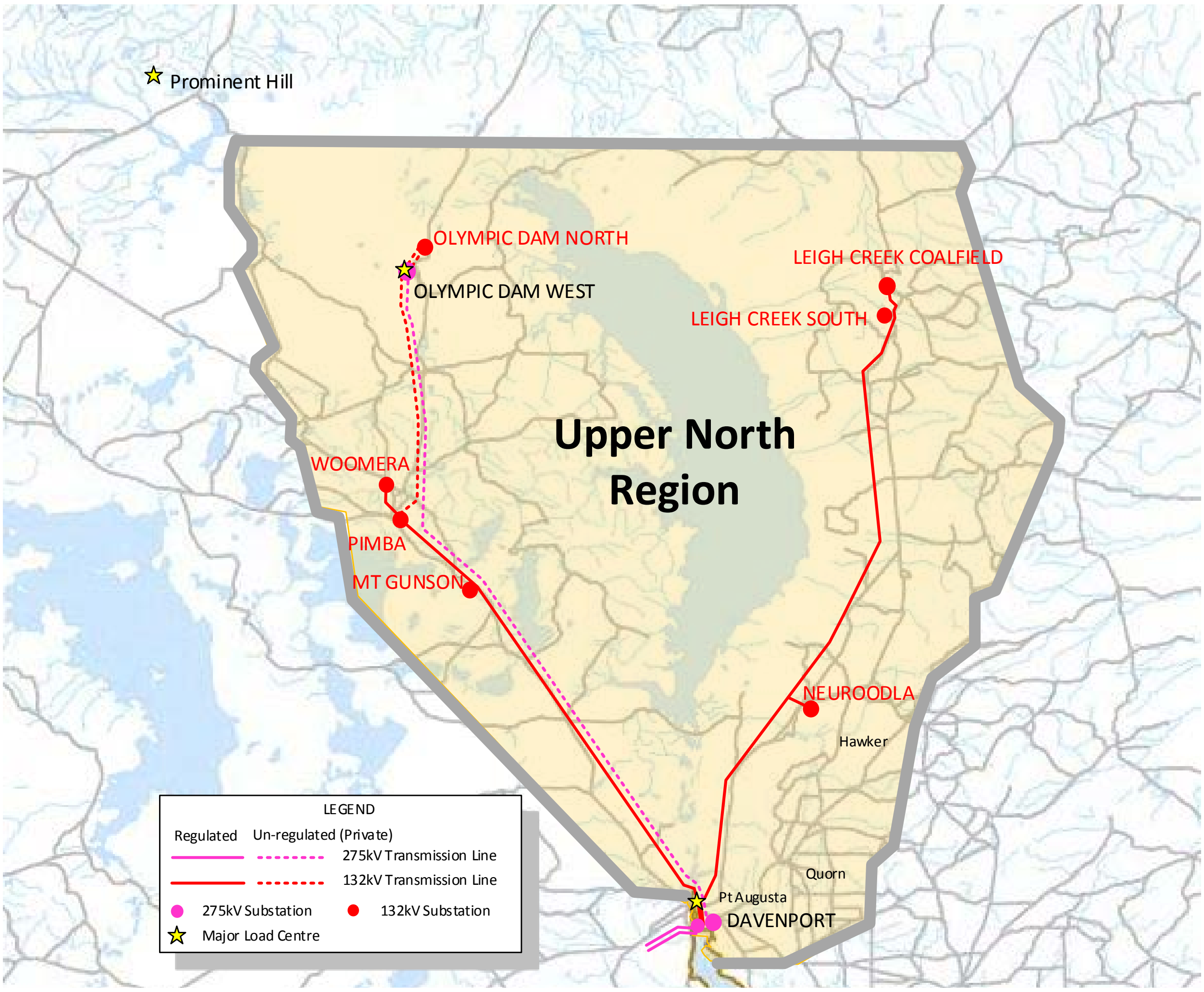

Figure C-7: Upper North transmission network and supply region

Appendix D Inter-regional transfer capacity

The combined maximum transfer capability for import into South Australia from Victoria under system normal operating conditions is 790 MW across the Heywood (section D1) and Murraylink (section D2) interconnectors.

The interconnector transfer capability will change once the upgrade to the Heywood interconnector is complete (mid-2016). The combined maximum transfer capability between South Australia and Victoria under system normal operating conditions will increase to 870 MW across the Heywood and Murraylink interconnectors. Interconnected network tests will determine the timing of released transfer capability between the two states.

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. New limit equations were developed based on new system load indices of Np =1.4 and Nq = 3.0 following the recent completion of the load indices measurements project.

   The updated 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 810MW. 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 Heywood interconnector upgrade has been completed, 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 export 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

The three-phase and single phase-to-ground fault levels under the 10% POE loading conditions for the South Australian transmission system in 2017–18 have been estimated (Table E-2). The fault level interruption capacity of the lowest rated circuit breaker(s) at each location should be taken only as an approximate guide to the conditions. 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.

Planned network augmentations (Table E-1) have been modelled for the future fault level calculations.

Table E-1: Augmentation project list

Commissioning Year	Scope of work
2016	Install a second 25 MVA transformer, rebuild and reconfigure 132 kV bus at Dalrymple Substation
2016	Heywood interconnector upgrade with series capacitor banks on the South East-Tailem Bend 275 kV lines and opening of the 132 kV lines

The following assumptions were made when calculating these fault levels:

- solid fault condition (i.e. no fault impedance modelled)
- all wind farms are online
- embedded generation at Starfish Hill, Angaston, Lonsdale, Port Stanvac, Whyalla, Canunda and KCA is online
- system normal network configuration – all network elements are in service
- TIPS 66 kV busbar sections are coupled.

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

Location	Bus voltage(kV)	Circuit breaker	2015–16 maximum fault level		2018–19 maximum fault level	
		lowest rating	3-phase	1-phase	3-phase	1-phase
Angas Creek	132	31.5	4.9	4.9	4.9	4.6
Angas Creek	33	13.1	5.3	6.6	5.3	6.6
Ardrossan West	132	21.9	2.5	2.4	2.6	2.6
Ardrossan West	33	17.5	4.2	3.2	4.4	3.3
Baroota	132	4.4	3.4	3.0	3.4	3.0
Baroota	33	17.5	1.6	1.7	1.6	1.7
Belalie	275	31.5	5.9	3.8	5.8	4.0
Berri	132	10.9	2.3	2.7	2.3	2.7
Berri	66	21.9	3.8	4.7	3.8	4.7

Location	Bus voltage(kV)	Circuit breaker	2015–16 maximum fault level		2018–19 maximum fault level	
		lowest rating	3-phase	1-phase	3-phase	1-phase
Berri	11	20	10.0	8.4	10.0	8.4
Back Callington	132	31.5	4.7	4.0	4.7	4.0
Back Callington	11	25	8.9	0.6	8.9	0.6
Black Range	275	40	N/A	N/A	7.2	3.8
Black Range	275	40	N/A	N/A	7.5	3.9
Blanche	132	21.9	5.5	5.6	5.5	5.6
Blanche	33	17.5	8.4	11.4	8.4	11.3
Blyth	275	31.5	5.2	4.7	5.3	4.8
Brinkworth	275	21	4.9	3.9	5.0	4.0
Brinkworth	132	15.3	7.8	8.7	7.9	8.8
Brinkworth	33	17.5	3.0	3.6	3.0	3.6
Bungama	275	31.5	5.0	4.3	5.2	4.4
Bungama	132	10.9	6.8	7.9	6.9	7.9
Bungama	33	13.1	10.4	6.4	10.5	6.5
Canowie	275	31.5	7.3	4.1	8.0	5.6
Cherry Gardens	275	31.5	12.2	12.7	13.0	13.3
Cherry Gardens	132	15.3	7.2	7.7	7.2	7.7
City West	275	40	13.5	16.8	14.4	17.7
City West - CBD	66	40	22.1	21.5	22.6	21.7
City West - South	66	40	18.6	13.6	18.9	13.6
Clare North	132	40	6.7	6.7	6.8	6.7
Clare North	33	31.5	9.3	6.9	9.3	6.9
Cultana	275	31.5	4.7	4.6	5.1	4.8
Cultana	132	31.5	6.6	7.0	6.8	7.1
Dalrymple	132	40	1.9	1.7	2.2	2.2
Dalrymple	33	8	2.4	3.2	4.0	5.5
Davenport	275	31.5	6.5	6.7	7.3	7.2
Davenport	132	40	6.8	8.2	7.1	8.3
Davenport	33	31.5	9.2	9.4	9.3	9.4
Dorrien	132	21.9	7.1	7.3	7.2	7.3
Dorrien	33	17.5	15.5	10.6	15.5	10.6
Dry Creek West	66	21.9	20.6	17.8	20.9	17.9
Dry Creek East	66	21.9	19.8	18.3	20.1	18.4
East Terrace	275	N/A	12.0	13.0	12.8	13.5
East Terrace	66	31.5	23.4	22.7	23.9	23.0
Happy Valley	275	31.5	11.9	12.6	12.7	13.1
Happy Valley	66	21.9	25.3	22.3	25.9	22.5
Hummocks	132	10.9	3.9	4.0	4.1	4.1

Location	Bus voltage(kV)	Circuit breaker lowest rating	2015–16 maximum fault level		2018–19 maximum fault level	
			3-phase	1-phase	3-phase	1-phase
Hummocks	33	17.5	4.7	4.7	4.7	4.7
Kadina East	132	40	2.2	2.5	2.2	2.6
Kadina East	33	17.5	5.5	4.2	5.7	4.3
Kanmantoo	132	10.9	4.8	4.2	4.9	4.2
Kanmantoo	33	N/A	1.6	1.7	1.6	1.7
Kanmantoo	11	13.1	3.9	2.4	3.8	2.4
Keith	132	15.3	3.6	3.3	2.2	2.1
Keith	33	31.5	4.8	6.1	4.0	5.1
Kilburn	275	31.5	14.6	15.6	15.6	16.3
Kilburn	66	21.9	20.6	17.8	20.9	17.9
Kincraig	132	15.3	2.9	2.8	2.6	2.6
Kincraig	33	17.5	4.5	6.2	4.3	5.9
Le Fevre	275	40	17.8	21.2	19.7	23.2
Le Fevre	66	25	29.4	27.4	29.9	27.6
Leigh Creek Coalfield	132	N/A	0.6	0.8	0.6	0.8
Leigh Creek Coalfield	33	8.7	1.5	2.1	1.5	2.1
Leigh Creek South	132	N/A	0.6	0.8	0.6	0.8
Leigh Creek South	33	18.4	0.9	1.3	0.9	1.3
Magill	275	15.7	13.2	14.1	14.1	14.7
Magill	66 (1)	21.9	23.2	27.3	23.7	27.7
Magill	66 (2)	21.9	11.9	8.2	12.0	8.2
Mannum	132	40	5.0	5.4	5.0	4.8
Mannum	33	31.5	5.2	4.9	5.2	4.9
Mannum – Adelaide Pump 1	132	N/A	4.5	4.6	4.5	4.0
Mannum – Adelaide Pump 1	3.3	N/A	27.7	32.3	25.5	25.7
Mannum – Adelaide Pump 2	132	N/A	4.7	4.8	4.7	4.1
Mannum – Adelaide Pump 2	3.3	N/A	20.4	24.0	25.6	25.8
Mannum – Adelaide Pump 3	132	N/A	4.6	4.8	4.6	4.0
Mannum – Adelaide Pump 3	3.3	N/A	24.3	28.9	25.6	25.8
Mayurra	132	40	7.6	5.8	7.4	5.7
Middleback	132	40	2.9	2.6	2.9	2.6
Middleback	33	N/A	1.5	2.1	1.5	2.1
Millbrook	132	10.9	5.2	5.1	5.2	4.7
Millbrook	3.3	N/A	20.5	24.7	17.9	18.2
Mintaro	132	20	7.8	8.1	8.0	8.2
Mobilong	132	15.3	6.2	6.5	6.1	6.3
Mobilong	33	31.5	9.3	7.0	9.2	6.9
Mokota	275	50	6.2	4.1	6.4	4.4

Location	Bus voltage(kV)	Circuit breaker lowest rating	2015–16 maximum fault level 3-phase	2015–16 maximum fault level 1-phase	2018–19 maximum fault level 3-phase	2018–19 maximum fault level 1-phase
Monash	132	31.5	2.4	2.8	2.4	2.9
Monash	66	N/A	3.6	4.7	3.6	4.7
Morgan – Whyalla Pump 1	132	15.3	4.2	4.1	4.2	4.1
Morgan – Whyalla Pump 1	3.3	N/A	25.3	25.6	25.4	25.7
Morgan – Whyalla Pump 2	132	15.3	4.8	4.1	4.9	4.1
Morgan – Whyalla Pump 2	3.3	N/A	18.0	18.0	18.0	18.1
Morgan – Whyalla Pump 3	132	15.3	7.8	7.2	7.9	7.0
Morgan – Whyalla Pump 3	3.3	N/A	30.8	2.0	18.7	19.1
Morgan – Whyalla Pump 4	132	15.3	9.5	8.7	9.7	8.6
Morgan – Whyalla Pump 4	3.3	N/A	31.0	2.0	18.9	19.3
Morphett Vale East	275	31.5	11.0	11.3	11.7	11.7
Morphett Vale East	66	25	21.5	17.1	21.8	17.3
Mount Barker	132	31.5	6.7	6.6	6.7	6.6
Mount Barker	66	31.5	11.1	11.8	11.2	11.9
Mount Barker South	275	40	10.6	10.2	11.2	10.5
Mount Barker South	66	66	11.4	11.3	11.5	11.3
Mount Gambier	132	15.3	6.7	6.5	6.7	6.6
Mount Gambier	33	17.5	6.9	5.9	7.2	5.9
Mount Gunson	132	15.3	1.1	1.1	1.1	1.1
Mount Gunson	33	N/A	1.3	1.3	1.3	1.3
Mount Millar	132	40	2.2	1.6	2.2	1.6
Mount Millar	33	31.5	10.4	1.4	10.3	1.4
Munno Para	275	40	11.9	11.1	12.6	11.5
Munno Para	66	40	13.9	10.5	14.1	10.5
Murray – Hahndorf Pump 1	132	15.3	5.4	5.3	5.3	5.2
Murray – Hahndorf Pump 1	11	N/A	12.7	13.3	12.7	13.2
Murray – Hahndorf Pump 2	132	15.3	5.9	5.7	5.9	5.5
Murray – Hahndorf Pump 2	11	N/A	13.0	13.5	12.9	13.4
Murray – Hahndorf Pump 3	132	15.3	5.6	5.2	5.6	5.1
Murray – Hahndorf Pump 3	11	N/A	13.0	13.4	13.0	13.3
Neuroodla	132	N/A	1.4	1.4	1.4	1.4
Neuroodla	33	8.7	1.4	1.4	1.4	1.3
New Osborne	66	40	31.4	30.8	32.0	31.1
North West Bend	132	10.9	4.2	4.3	4.2	4.3
North West Bend	66	13.1	4.3	4.9	4.3	4.9
Northfield	275	31.5	14.5	15.0	15.5	15.7
Northfield	66	31.5	27.0	24.3	27.7	24.7
Para	275	31.5	16.7	19.0	18.2	20.2

Location	Bus voltage(kV)	Circuit breaker lowest rating	2015–16 maximum fault level 3-phase	2015–16 maximum fault level 1-phase	2018–19 maximum fault level 3-phase	2018–19 maximum fault level 1-phase
Para	132	21.9	8.4	9.1	8.5	9.0
Para	66	21.9	18.3	15.7	18.6	15.8
Para	11 (SVC)	N/A	30.7	26.6	31.3	27.1
Parafield Gardens West	275	31.5	15.2	16.9	16.5	17.9
Parafield Gardens West	66	31.5	17.9	15.1	18.3	15.2
Pelican Point	275	40	17.5	20.5	19.4	22.6
Penola West	132	31.5	5.2	6.0	5.1	5.9
Penola West	33	31.5	5.3	5.0	5.3	5.0
Pimba	132	31.5	0.9	0.9	0.9	0.9
Playford	275	10.5	6.3	6.4	7.0	6.8
Playford	132	10.9	4.3	4.7	4.4	4.8
Port Lincoln Terminal	132	10.9	2.7	3.0	2.7	3.0
Port Lincoln Terminal	33	17.5	6.6	5.0	6.6	5.0
Port Lincoln Terminal	11	13.1	9.2	7.9	9.2	7.9
Port Pirie	132	40	5.5	5.8	5.6	5.8
Port Pirie	33	13.1	8.8	5.3	8.9	5.3
Redhill	132	N/A	6.5	5.4	6.6	5.4
Robertstown	275	31.5	9.0	7.0	9.8	8.2
Robertstown	132	31.5	10.5	10.9	10.8	11.1
Roseworthy	132	31.5	7.2	6.1	7.3	6.2
Roseworthy	11	25	8.9	12.2	8.9	12.2
Sleaford	132	40	2.4	1.8	2.4	1.8
Snowtown	132	N/A	4.3	3.0	4.4	3.0
Snuggery	132	10.9	8.8	9.1	8.4	8.7
Snuggery (Industrial)	33	8.7	11.6	14.3	11.2	14.0
Snuggery (Industrial)	11 (Cap)	13.1	11.7	10.2	11.6	10.1
Sunggery (Rural)	33	8.7	3.7	4.9	3.5	4.7
Snuggery (Rural)	11 (Cap)	13.1	6.0	5.2	5.7	5.0
South East	275	31.5	7.8	8.0	8.7	8.6
South East	132	20	10.4	11.5	10.7	11.7
Stony Point	132	31.5	3.6	2.7	3.7	2.8
Stony Point	11	N/A	9.6	0.3	9.6	0.3
Tailem Bend	275	21	7.7	5.6	8.5	5.8
Tailem Bend	132	21.9	7.1	8.0	6.8	7.7
Tailem Bend	33	25	6.0	7.6	5.9	7.5
Templers	132	10.9	7.7	7.3	7.8	7.3
Templers	33	8.7	9.9	7.2	10.0	7.2
Templers West	275	31.5	8.1	7.1	8.4	7.3

Location	Bus voltage(kV)	Circuit breaker	2015–16 maximum fault level		2018–19 maximum fault level	
		lowest rating	3-phase	1-phase	3-phase	1-phase
Templers West	132	40	7.3	7.0	7.4	7.1
Quarantine 1	66	N/A	14.4	14.0	14.5	14.1
Quarantine 2	66	N/A	16.5	12.9	16.6	12.9
Torrens Island	275	31.5	18.9	23.6	20.7	25.5
Torrens Island	66	40	31.7	30.6	32.2	30.9
Tungkillo	275	50	11.8	10.5	12.7	10.9
Waterloo	132	10.9	9.7	8.6	9.9	8.6
Waterloo	33	13.1	6.1	4.3	6.2	4.3
Waterloo East	132	N/A	9.6	8.0	9.8	8.0
Whyalla Central	132	40	5.9	6.3	6.1	6.3
Whyalla Central	33	40	14.7	8.2	14.9	8.2
Whyalla Terminal (LMF)	132	10.9	5.7	6.0	5.9	6.1
Whyalla Terminal (LMF)	33	17.5	4.7	4.7	4.7	4.7
Wudinna	132	31.5	1.0	1.1	1.0	1.1
Wudinna	66	21.9	1.5	1.7	1.5	1.7
Yadnarie	132	10.9	2.6	2.5	2.6	2.5
Yadnarie	66	40	2.7	3.2	2.7	3.2
Yadnarie	11 (Reactor)	18.4	6.3	5.4	6.3	5.4

Appendix F Non-network solutions

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

F1 Non-network solutions framework

ElectraNet's non-network 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 non-network 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 non-network solution option is shown to be the most cost effective technically viable solution, then a network support agreement is negotiated with the proponent.

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

- existing embedded generation
- new embedded generation
- demand response.

F2 Non-network solutions planning assessment

Non-network 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.

Any options which have a high risk of not being delivered in time to meet the identified network need are excluded. Remaining options 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 non-network solution is deemed economically feasible if the NPV cost of demand reduction (single or combined) is less than the NPV of the alternative network solution. 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 Example of non-network solution assessment costs

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

- customer demand reduction costs $150,000–$200,000 per MW
- generator support costs of $200,000–$400,000 per MW.

These figures yielded optimal annual cost estimates for a three-year demand reduction program in 2011–12 dollars (Table F-1).

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

	2016–17	2017–18	2018–19	2019–20
Demand reduction (MW)	0[45]	1.5	3.6	5.7
Annual cost	$200 000	$270 000	$648 000	$1 026 000

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

F4 Projects for which ElectraNet requests proposals for non-network solutions

Recently completed, in-progress, and planned consultations for forecast limitations on which ElectraNet seeks proposals for non-network solutions are outlined in Table F-2.

Table F-2: Recent and planned projects

Project	Project timing	Consultation status
Baroota Connection Point Upgrade Refer to Table G-3	2017	Application of the RIT-T indicated that the available network and non-network options were unable to provide a positive net market benefit After public consultation, ESCOSA amended the ETC to remove the requirement for Baroota connection point to be upgraded to meet the category 2 reliability standard ElectraNet has adjusted the focus of this project to replacement and refurbishment to address the asset condition needs at Baroota
Energy Storage for Commercial Renewables Integration in South Australia Refer to section 3.2.4 of this report	2018	If this project is funded by ARENA, ElectraNet will prepare a project specification consultation report (PSCR) for planned issue towards the end of 2016 Proponents of potential non-network solutions will be encouraged to make a submission in response to the PSCR
Address Eyre Peninsula 132 kV Line Conductor Condition and Provide Port Lincoln Network Support Refer to section 7.3.4	2018	The current network support arrangement that enables ElectraNet to meet the ETC category 3 reliability standard at Port Lincoln expires in June 2018, and significant portions of the conductor on the Eyre Peninsula 132 kV lines is in poor condition ElectraNet is currently considering the best way to seek proposals for non-network solutions to continue to meet the reliability standard and address the poor conductor condition
Gawler East New Connection Point Refer to section 7.2.3.5 of this report	2019	Application of the RIT-D is planned to begin with publication by SA Power Networks of a NNOR for this project before the end of 2016 Proponents of potential non-network solutions will be encouraged to make a submission in response to the NNOR
Northern SA Voltage Control Refer to section 7.2.3.1 of this report	2019	ElectraNet is currently preparing a PSCR Proponents of potential non-network solutions will be encouraged to make a submission in response to the PSCR
Improve South Australian System Security (New Interconnector) Refer to section 3.2.3 of this report	~2023	ElectraNet is currently preparing a PSCR, planned for issue late in September 2016 Proponents of potential non-network solutions will be encouraged to make a submission in response to the PSCR

Appendix G Augmentation, security and compliance, replacement and refurbishment, and contingent projects

Emerging network limitations and solutions have been identified during scenario analysis (Table G-1). 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 sections 7.1.2, 7.1.3 and 7.2 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 G-2), 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 G-3), including the projects already covered in section 7.4. Currently there are no economically feasible non-network solutions that could resolve the limitations presented.

ElectraNet is assessing detailed asset condition and replacement requirements for the 2018–23 regulatory control period. Where details are not yet available, summary entries for line, substation and protection system unit asset replacements are provided. ElectraNet plans to expand these prior to submission of the 2018–23 revenue proposal, which is due in January 2017.

Contingent projects that that ElectraNet is considering for the 2018-23 regulatory control period are listed in Table G-4.

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

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

Project timing	Limitation	Proposed solution	Category	Region	Estimated cost ($M)
	Committed and Pending Projects				
2016	Heywood Interconnector transfer limitations due to system stability and thermal constraints	Install 50% series compensation on the South East – Tailem Bend 275 kV lines; remove rating restrictions from South East 275 kV and 132 kV lines; implement a run-back control scheme for Lake Bonney Wind Farm to manage light load and high wind condition; and AusNet Services to install a third 500/275 kV transformer at Heywood	Augmentation and market benefit	Main Grid and South East	35-45 (ElectraNet costs only)
2016	ETC reclassification to category 2 required N-1 transformer redundancy at Dalrymple connection point from 1 December 2016	Install a second 25 MVA transformer and associated switchgear at Dalrymple substation	Connection	Mid North	8-10 (ElectraNet costs only)
2016	Deterministic line ratings in various parts of the network can cause constraints at times of high demand or high wind generation	Install modern weather stations at various monitoring locations to facilitate the implementation of dynamic line ratings on critical circuits	Augmentation and market benefit	Various	<5
2016	Congestion on the 275 kV network between South East and Tailem Bend restricts transfer capability between South Australia and Victoria across the Heywood Interconnector, following completion of the Heywood Interconnector Upgrade in 2016	Uprate the South East – Tailem Bend 275 kV lines to 120˚C line clearances	Market benefit (NCIPAP)	Main Grid	<5
2016	Congestion on the 275 kV and 132 kV networks north of Tailem Bend restricts transfer capability between South Australia and Victoria across the Heywood Interconnector, following completion of the Heywood Interconnector Upgrade in 2016	Uprate the Tailem Bend – Tungkillo 275 kV line and the Tailem Bend – Mobilong 132 kV line to 100˚C line clearances	Market benefit (NCIPAP)	Main Grid / Eastern Hills	<5

Project timing	Limitation	Proposed solution	Category	Region	Estimated cost ($M)
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
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 (All Scenarios)				
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 (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 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	10-20
2019	Potential network adequacy and security limitations resulting from the withdrawal of the network voltage control service provided by Northern Power Station at the Davenport 275 kV substation,	Install dynamic 275 kV reactive support at Davenport substation	Augmentation	Main Grid	Up to 60
2019	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)

Project timing	Limitation	Proposed solution	Category	Region	Estimated cost ($M)
2020	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 132 kV lines from Cultana to Yadnarie and from Yadnarie to Port Lincoln, and decommission the existing 132 kV lines	Augmentation	Eyre Peninsula	100-150
	Potential Projects (SA Mining Growth Scenario)				
When or if needed: within 10 years?	Subject to connection of a new large mining load on the Eyre Peninsula: at high demand times the Middleback – Yadnarie 132 kV line will be overloaded under normal conditions, and an outage of one Cultana 275/132 kV transformer would overload the other Cultana transformer	Reinforce the Eyre Peninsula network by constructing a double-circuit 275 kV line from Cultana to a location near Yadnarie, initially strung only on one side; establish a 275/132 kV substation near Yadnarie; and supply new mining load(s) via 275 kV and 132 kV supplies from the new substation	Augmentation	Eyre Peninsula	150–300
	Potential Projects (SA Renewable Generation Expansion Scenario)				
When or if needed: within 10 years?	Subject to connection of new wind farms to the 275 kV lines between Davenport and Robertstown, 275 kV lines may be overloaded at times of high wind generation	Increase the capacity of the 275 kV lines between Davenport and Robertstown by upgrading various items of plant (e.g. remove line traps, replace current transformers, change current transformer ratios) and apply dynamic line ratings to these lines	To be considered for 2018 – 2023 NCIPAP	Main Grid	<5
When or if needed: within 10 years?	Subject to connection of new wind farms to the 275 kV lines between Davenport and Robertstown, an outage of one of the Robertstown 160 MVA 275/132 kV transformers would overload the other Robertstown transformer	Increase the capacity of the Robertstown 275/132 kV transformers by upgrading various items of plant and apply short term loading limits to the Robertstown 160 MVA 275/132 kV transformers	To be considered for 2018 – 2023 NCIPAP	Main Grid/ Mid North	<5
When or if needed: within 10 years?	Subject to connection of new wind farms to the Mid North 132 kV lines or the 275 kV lines between Davenport and Para (the “East” and “West” circuits): the thermal rating of various 132 kV lines in the Mid North may constrain wind farm generation dispatch, based on the need to avoid overloading lines following a single credible contingency	Implement a control scheme that will reconfigure the Mid North 132 kV network at times of high wind farm generation by opening and closing 132 kV circuit breakers as required, to target reduced congestion under various operating conditions	To be considered for 2018 – 2023 NCIPAP	Mid North	<5

Project timing	Limitation	Proposed solution	Category	Region	Estimated cost ($M)
When or if needed: within 10 years?	Subject to the connection of new wind farms in South Australia, increased congestion on the 275 kV network between Tungkillo and Heywood is forecast to limit exports from South Australia to Victoria	Increase the capacity of the 275 kV lines between Tungkillo and Heywood by upgrading various items of plant (e.g. remove line traps, replace current transformers, change current transformer ratios) and apply dynamic line ratings	To be considered for 2018 – 2023 NCIPAP	Main Grid	<5
When or if needed: within 10 years?	Subject to the connection of new wind farms in South Australia, increased congestion on the 275 kV network between Tungkillo and Tailem Bend is forecast to restrict exports from South Australia to Victoria across the Heywood Interconnector	Increase the capacity of the Tungkillo to Tailem Bend 275 kV corridor by stringing the vacant 275 kV circuit between Tungkillo and Tailem Bend	Market benefit	Main Grid	25–50
When or if needed: within 10 years?	Subject to the connection of new wind farms in South Australia, increased congestion on the 132 kV network between Robertstown and Monash is forecast to restrict exports from South Australia to Victoria across the Murraylink interconnector	Install two switched 15 Mvar 132 kV capacitor banks at Monash	Market Benefit	Riverland	5-10

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	Estimated cost ($M)
	Committed and Pending Projects			
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	8-12
2017	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
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
	Proposed Projects			
2017	Shutdown of regionally important substations required during outages of Cultana to Yadnarie 132 kV transmission line	Install Eyre Peninsula islanding control scheme to minimise interruptions to customers	Eyre	<5
2018	Outages and constraints on the Murraylink Interconnector	Redesign and replace the Murraylink control scheme	Riverland	<5
2018	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	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
2019	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	Estimated cost ($M)
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
2023	Following a single contingency of an in-service generator, steady-state voltage levels on the South Australian transmission system may breach 110% at minimum demand times from 2023-24	Install a switched 50 Mvar 275 kV reactor at Templers West	Main Grid	<5
2018–23	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
2018–23	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	5–10
2018–23	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 reactors and resistor installations across the network	Various	<5
	Potential Projects			
2018 – 23	Mintaro and Angaston generators are constrained off during 132 kV outages that result in these generators being radialised	To be considered for 2018 – 2023 NCIPAP Implement full single pole reclosing capability on the 132 kV circuits in the Mid North region	Mid North	<5
2018–23	Ladbroke Grove and Snuggery generators are constrained off during 132 kV outages that result in these generators being radialised	To be considered for 2018 – 2023 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	Estimated cost ($M)	Alternative option(s)
	Committed and pending projects				
2016	Porcelain disc insulators on 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
2016	Porcelain disc insulators on Tailem Bend to Keith #2 132 kV line are at end-of-life, leading to a high failure rate and fire start risk	Replace all porcelain disc insulators on Tailem Bend to Keith #2 132 kV line to achieving a 15-year life extension	South East	5–8	Assess and replace insulators on sample-based testing results
2016	Condition of the existing Para SVCs secondary systems and the lack of spare parts make maintenance impossible. Manufacturer support is largely withdrawn. Failure would severely constrain interconnector transfer capacity	Replace the existing SVC thyristor valves and thyristor valve cooling, protection and control systems for both SVCs at Para substation with modern-day equipment. Install circuit breakers and associated plant to connect both SVCs to east and west busbars. Install a 50 Mvar reactor at Para substation to provide reactive support during SVC outages	Main Grid	20-25	Replace individual components that are reaching end-of-life or Replace control systems only
2016	Morgan to Whyalla 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 Morgan to Whyalla pumping station #2 supply site to current day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Riverland	10–15	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites

Project timing	Limitation	Recommended solution	Region	Estimated cost ($M)	Alternative option(s)
2016	Morgan to Whyalla pumping station #1 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 #1 supply site to current day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Riverland	10–14	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites
2016	Morgan to Whyalla 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 Morgan to Whyalla pumping station #3 supply site to current day standards and replace the 132/3.3 kV transformers. Employ a standardised approach across all pumping station sites to realise design and operational efficiencies	Riverland	10–13	Replace selected primary plant based on condition or Replace all plant without applying improved standardisation with other sites
2016	Morgan to Whyalla pumping station #4 primary plant 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 #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

Project timing	Limitation	Recommended solution	Region	Estimated cost ($M)	Alternative option(s)
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 #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	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 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
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	46–60	Rebuild 275 kV line in an adjacent easement and retire old line or Replace load-releasing cross arms with standard cross arms (and also strengthen the towers) and use sample-based testing results to assess and replace insulators

Project timing	Limitation	Recommended solution	Region	Estimated cost ($M)	Alternative option(s)
2013-18	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	45-55	Replace individual assets on failure
	Proposed projects				
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	5–10 (ElectraNet costs only)	Rebuild substation at a new location
2018	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
2018	AC auxiliary supplies at older substations are not compliant with current Australian standards and have some safety hazards and operational deficiencies	Replace AC auxiliary supply equipment, switchboards and cabling at 13 substations	Various	<5	Replacing sub-standard and hazardous equipment is considered to be the only viable option
2018	A number of substation battery charger units have reached the end of their practical life. 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
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
2018–23	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	8–10	Replace individual components or sections on failure or Full line replacement

Project timing	Limitation	Recommended solution	Region	Estimated cost ($M)	Alternative option(s)
2018–23	Transmission line insulator systems at end-of-life, leading to a high failure rate, and safety and network availability 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
2018–23	Transmission line conductor and earthwire components at end-of-life, leading to a high failure rate, and safety and network availability risk	Implement a program of transmission line conductor and earthwire refurbishment to renew line asset components and extend line life	Various	10–20	Replace individual corroded conductor sections or Full line replacement
2018–23	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 replacements at various substations	Various	30–45	Replace assets on failure
2018–23	Various individual substation protection 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	Replace 400–500 protection scheme relay assets	Various	30–40	Replace assets on failure
2018–23	Many items of online condition monitoring equipment will be near the end of their usable lives in the 2018-23 period (12-20 years old) and are exhibiting high failure rates	Replace obsolete online asset condition monitoring equipment	Various	10–15	Continue corrective maintenance program only
2018–23	Mannum transformers 1 and 2 have been assessed to be at the end of their technical lives and at high risk of failure	Replace the existing transformers with two new 132/33 kV transformers at Mannum substation	Eastern Hills	<5	Replace assets on failure
2018–23	Mount Gambier transformer 1 has been assessed to be at the end of its technical life and at high risk of failure	Replace the existing 50 MVA transformer with a new 25 MVA 132/33/11 kV transformer at Mount Gambier substation	South East	4–8	Replace asset on failure

G4 Summary of contingent projects being considered for inclusion in ElectraNet's 2018-23 revenue reset proposal

Table G-4: Contingent projects being considered for inclusion in ElectraNet's 2018-23 revenue reset proposal

Trigger	Potential solution(s)	Reference	Estimated cost ($M)
Eyre Peninsula major upgrade Connection of a large new mining load requires augmentation of the Eyre Peninsula network	Construct a new double circuit 275 kV line (initially strung only on one side) from Cultana to Yadnarie, extend supply from Yadnarie to the new mining connection, and establish a single transformer 275/132 kV injection into the 132 kV network at Yadnarie	Section 7.2.4.1	100-150
Insufficient minimum fault currents Insufficient conventional generation dispatched to ensure that fault currents are sufficiently high to allow protective devices to detect and clear faults on the network	Install two synchronous condensers (designed to contribute strongly to fault currents) at a central location Alternative options may include an extensive upgrade to protection and communications systems on many of ElectraNet's lines	Section 3.2.5	40-70
New interconnector A new interconnector from South Australia to New South Wales or Victoria shown to be economically viable (deliver net market benefits) via application of the RIT-T	Construct a new interconnector between South Australia and New South Wales or Victoria	Section 3.2.3	300-700
Yorke Peninsula major upgrade Insufficient network capacity to connect a new major load on the Yorke Peninsula	Construct a new 275 kV line from Blythe West to Hummocks and establish a single transformer 275/132 kV injection into the 132 kV network at Hummocks	N/A	30-60

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

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

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