Transmission Annual Planning Report

October 2021

ElectraNet

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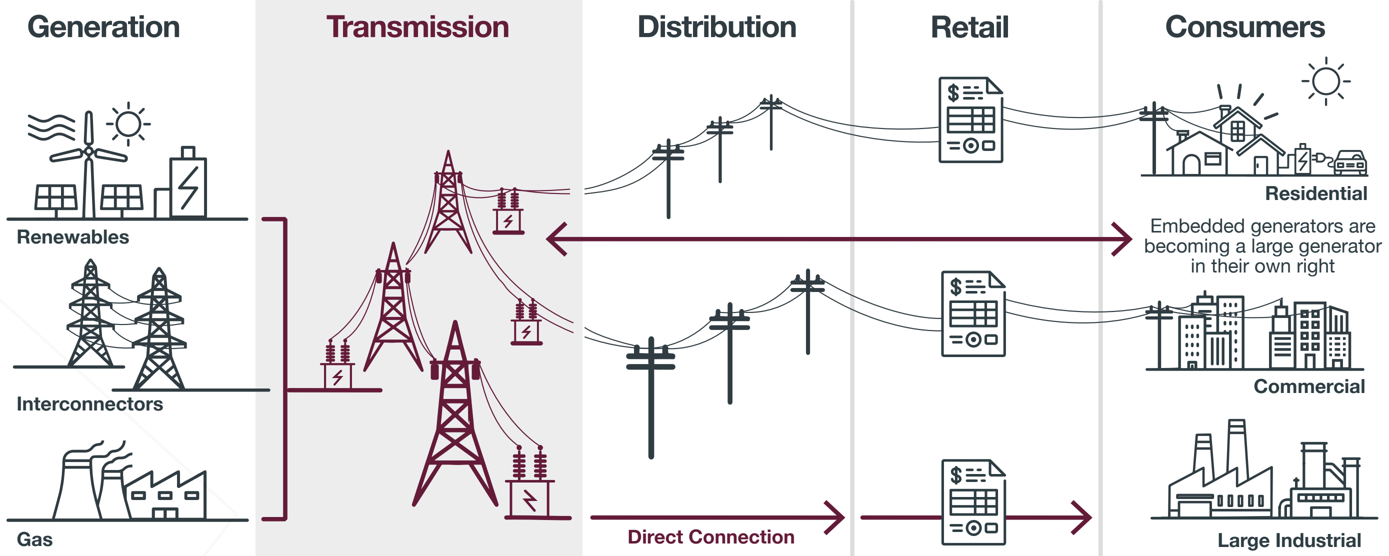
About ElectraNet

ElectraNet powers people's lives by delivering safe, affordable, and reliable solutions to power homes, businesses, and the economy.

As South Australia's principal electricity Transmission Network Service Provider (TNSP), we are a critical part of the electricity supply chain. We own and manage the high-voltage transmission lines and substations that connect this State's electricity customers, including those connected to SA Power Networks' lower-voltage distribution network, to generation sources both locally and interstate.

We also provide connection and other services to customers and generators wanting to connect to the high-voltage electricity transmission network.

Role of ElectraNet in the electricity supply chain



Generation: Electricity is generated from traditional and renewable energy sources such as wind, solar and gas.

Transmission: Electricity enters ElectraNet's network where it is converted to higher voltages, for efficient long-distance transport to cities and towns around South Australia. The voltage is then lowered so it can enter the distribution network or be supplied directly to some large industrial customers.

Distribution: The distribution network, operated in South Australia by SA Power Networks, transports low-voltage electricity to residential and commercial customers.

Retail: Retailers are the primary point of contact for residential and commercial customers. They coordinate connections and manage billing and payments.

Consumers: The traditional flow of electricity supply is changing. Over one in three South Australian homes now combines the electricity they draw from the network with power generated by rooftop solar panels, and also contributes surplus electricity back to the network.

Purpose of the Transmission Annual Planning Report

Each year, ElectraNet reviews the capability of South Australia's electricity transmission network and regulated connection points to ensure they are adequate to meet the ongoing demand for electricity transmission services, forecast under a variety of operating scenarios.

ElectraNet undertakes joint planning with SA Power Networks, which is responsible for the low voltage distribution of electricity throughout South Australia, to complete the review. We also consider the findings of AEMO's Integrated System Plan and the outcomes of joint planning with Powerlink in Queensland, TransGrid in New South Wales, AusNet Services in Victoria, and the Australian Energy Market Operator (AEMO) in its roles as Victorian Transmission Planner and National Transmission Planner (Appendix B).

This report presents the outcomes of the annual planning review and forecasts to help you understand the current capacity of the transmission network and how we think this may change in the future. The report covers a 10-year planning period (1 November 2021 to 31 October 2031) and identifies potential network capability limitations and possible solution options.

The report provides information on:

- trends and directions for the future of the electricity transmission system (Chapter 1)
- national transmission planning (Chapter 2)
- demand forecast for the next 10-year period (Chapter 3)
- system capability and performance (Chapter 4)
- connection and demand management opportunities (Chapter 5)
- recently completed, committed, and planned projects (Chapter 6)
- transmission system development plans (Chapter 7).

The report does not identify a single specific future development plan for the South Australian transmission system. Rather it is intended to form part of an ongoing consultation process to ensure the efficient and economical development of the transmission network to meet forecast electricity demand and support the transition to renewable energy sources over the planning period. Decisions by ElectraNet to invest in the South Australian transmission system are subject to further detailed investigation and economic assessment that will be undertaken closer to the time the investments are needed.

We invite feedback on any aspect of this report. Your feedback will help us to serve you better and ensure we can provide reliable electricity transmission services that contribute to an affordable electricity supply to customers.

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

Comments and suggestions can be directed to:

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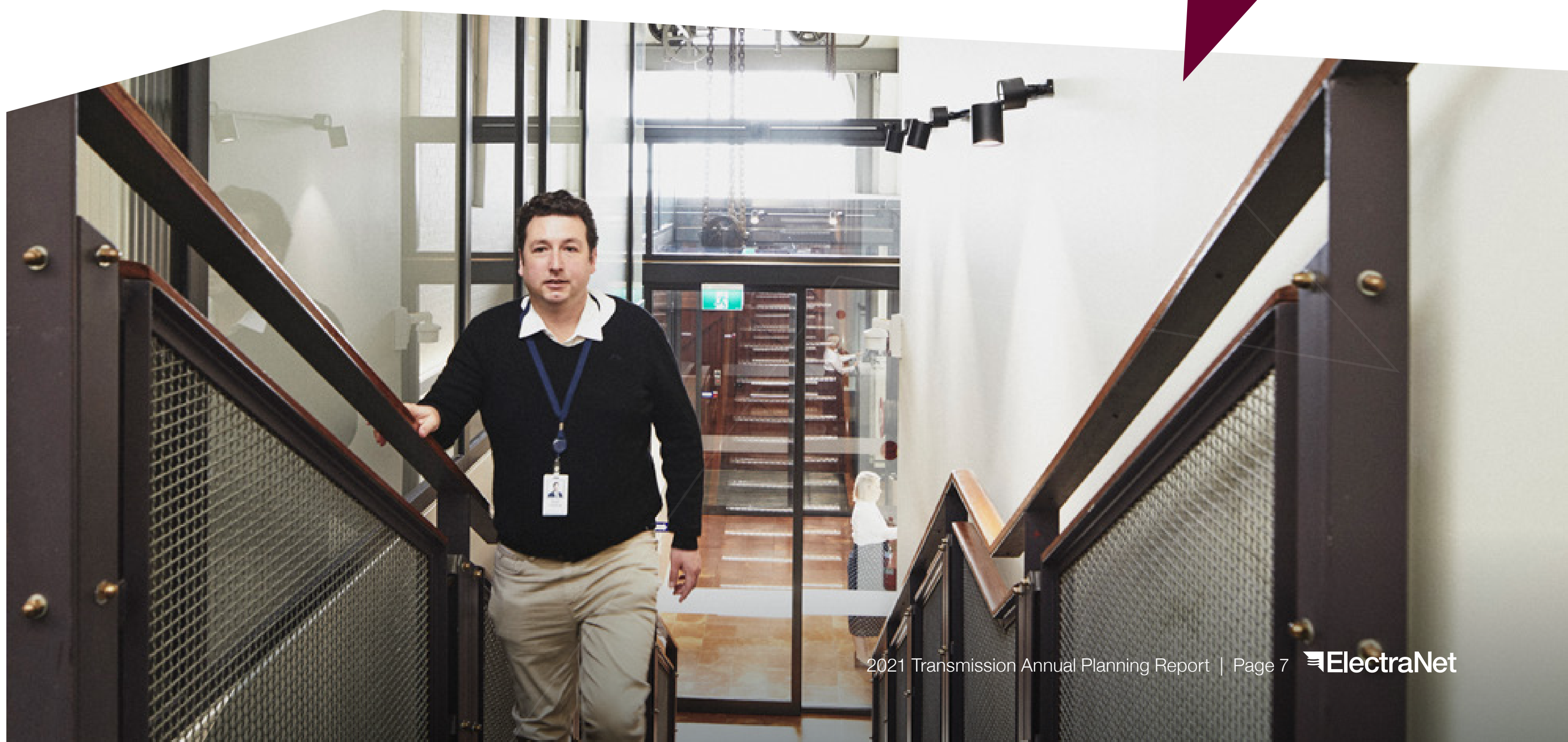


Executive Summary

South Australia remains at the forefront of changes sweeping electricity systems worldwide.

Renewable electricity sources such as solar, wind, and batteries, and small-scale renewables in homes and businesses, are displacing thermal generation such as gas. Collectively, they are the largest generator in South Australia. As Australia moves to reduce greenhouse gas emissions, their role will only continue to increase.

This is creating greater variability in electricity generation and demand, and is pushing the power system beyond its technical limits. This presents new challenges to reliability, affordability, and system security.

We have an increasing role to play in addressing these challenges. While the grid was once used to 'deliver' electricity from large remote generators to customers, it is increasingly being used to move electricity back and forth between regions and local areas, and to provide essential system services that were once provided by thermal generators.

We have installed four synchronous condensers to supply essential system services that are being lost as conventional generators operate less and ultimately retire and are implementing special protection schemes to protect the power system from disturbances in an increasingly complex operating environment.

With the ever-increasing penetration of variable renewable generators, we will be called on to provide even more of these services in the future.

We are also implementing the South Australian component of the new electricity interconnector between South Australia and New South Wales (Project EnergyConnect) to support the transformation of the power system and drive down energy costs.

While these strategic investments, identified as priorities by the Australian Energy Market Operator (AEMO) in its Integrated System Plan, will add to the cost of transmission services, they will deliver much greater benefits to customers through overall savings in their electricity bills.

While transmission is a small part of the overall cost of electricity, typically less than 10 per cent, the network will continue to play a key role in the safe and reliable supply of electricity and in supporting the ongoing transformation of the power system.

Our annual planning process focuses on ensuring system security and reliability and seeks to forecast network limitations and opportunities, and ensure plans are in place to address them in a timely and efficient manner.

Our network planning considers a range of potential future scenarios and developments, including supply-side developments that would be needed to meet the South Australian government's aspirational target of 100% renewable generation in South Australia by the 2030s.

We also look further ahead and assess potential major developments over a 20-year period as we consider AEMO's Integrated System Plan (ISP).

Over the next five to ten years, our planning indicates that capital investment in the transmission network will be dominated by the need for prioritised asset replacement and refurbishment for a range of assets on South Australia's electricity transmission network.

Capital investment is also needed to address the challenges emerging from the increasing penetration of distributed energy resources. This includes additional reactive support at various locations to maintain an adequate reserve of dynamic reactive power capability at times of low or negative net system demand, maximising the availability of dynamic reactive power devices to respond to system disturbances. We also propose to expand a Wide Area Monitoring Scheme to enable early detection of performance issues on the system.

A range of other needs are expected to emerge over the planning horizon that could arise earlier. These include potential needs to:

- address any new obligations to provide system strength or other system services,
- unlock Renewable Energy Zone (REZ) capacity to enable continuing supply side changes (AEMO's 2020 ISP indicates that capital investment to unlock South Australian REZs is likely to be needed in the 2030s, but our planning indicates that it could be required sooner if new generators connect earlier than currently forecast)
- facilitate the connection of new large loads such as mines or hydrogen hubs
- enable the growth of distributed demand such as could occur due to appliance electrification or a widespread uptake of EVs
- further increase interconnector transfer capability and/ or provide other balancing services to maintain a secure system during times when generation from distributed energy resources exceeds total demand.

We propose to manage the potential risk of these needs emerging earlier than currently forecast with contingent projects that can be triggered if necessary to enable us to respond appropriately.

Connection of renewable energy generation continued during 2020-21 and based on active connection enquiries and applications we expect that the amount of South Australian generation coming from renewable sources will continue to increase. This current and anticipated connection activity aligns most closely with the results of AEMO's "Step Change" scenario of NEM-wide generation expansion from the 2020 Integrated System Plan.

Our response to the current challenges facing South Australia's changing electricity system includes:

- participating in the ongoing national conversation about energy transformation and engaging in joint planning with AEMO, other TNSPs and SA Power Networks to develop plans to support the changing needs of customers and the power system
- building Project EnergyConnect, a new interconnector between South Australia and New South Wales to deliver economic benefits to customers by better sharing of energy resources across the National Electricity Market (NEM)
- the completed installation of four large synchronous condensers, raising the existing cap on the dispatch of non-synchronous generation, and assisting in delivering adequate levels of system strength and system inertia for South Australia's power system
- building Eyre Peninsula Link, a new double-circuit transmission line that will improve reliability for customers on Eyre Peninsula
- planning to install additional reactive support at various locations for transmission network voltage control and to address an emerging need to maintain an appropriate reserve of dynamic reactive power capability at times of low or negative net system demand
- investigating potential challenges and solutions to meet the future needs of South Australia's electricity customers.

This South Australian Transmission Annual Planning Report summarises the latest outcomes of our planning process. Together with our supporting datasets and online interactive map (available **here**) it provides 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, historical performance, demand projections, emerging network limitations or constraints, and information on completed, committed, pending and proposed transmission network developments.

This report is designed to inform stakeholders and help potential generators and users of electricity to identify and assess opportunities in the South Australian region of the NEM.

We're enabling the development of Australia's future electricity system

Ongoing national conversation about energy transformation

Building Project EnergyConnect

Completed installation of four large synchronous condensers

Building Eyre Peninsula Link

Planning to install additional reactive support

Meeting the future needs of South Australia's electricity customers

2021 Highlights

Project EnergyConnect

Final regulatory funding approvals for the construction of Project EnergyConnect in South Australia and New South Wales were obtained from the AER in June 2021.

Project EnergyConnect involves the construction of a new 330 kV interconnector from Robertstown in South Australia to Wagga Wagga in New South Wales. Transfer capacity will be up to about 800 MW.

Implementation of Project EnergyConnect will also increase the maximum amount that can be transferred across the Heywood interconnector to a transfer capacity of up to about 750 MW.

Once fully delivered, the full combined transfer limit across both the Heywood and Project EnergyConnect interconnectors will be 1,300 MW into South Australia and 1,450 MW export.

In January 2020, the AER published a RIT-T determination including that Project EnergyConnect remained the most "credible option that maximises the net economic benefit" in the NEM, ultimately benefitting electricity consumers. AEMO's 2020 ISP identifies Project EnergyConnect as part of the optimal development path for the NEM.

Project EnergyConnect will support Australia's growing renewable energy industry, with new wind and solar projects planned for South Australia, New South Wales and Victoria expected to benefit from the new interconnector.

In South Australia, Project EnergyConnect's Environment Impact Statement is currently undergoing assessment by the South Australian Government's Planning and Land Use Services. Subject to receiving all necessary environmental approvals, construction is anticipated to start later this year with commissioning planned to commence in 2023.

Eyre Peninsula Link

Construction of Eyre Peninsula Link started in mid-2021. This project will replace the existing 132 kV lines between Cultana and Port Lincoln with a new double-circuit line between Cultana and Yadnarie that is initially energised at 132 kV, but which has the option to be energised at 275 kV if required in the future, and with a new double-circuit 132 kV line between Yadnarie and Port Lincoln. We plan to energise Eyre Peninsula Link by the end of 2022.

Market benefit opportunities

Our plan includes a range of projects that will reduce the impact of existing and forecast network constraints, delivering net market benefits. This includes projects that form ElectraNet's 2018-19 to 2022-23 Network Capability Incentive Parameter Action Plan (NCIPAP), as well as new proposed projects to relieve constraints in our 2023-24 to 2027-28 NCIPAP.

Control schemes

With the rapid evolution of the power system, we expect that the need for emergency control schemes to manage both credible and non-credible system events will continue to grow.

We are collaborating with AEMO to augment the existing System Integrity Protection Scheme (SIPS) to a more sophisticated Wide Area Protection Scheme (WAPS). The final scheme is expected to be commissioned by October 2022. As part of Project EnergyConnect, a Special Protection Scheme will be implemented to cater for the non-credible loss of either Project EnergyConnect or Heywood interconnector. The WAPS will also be reviewed when Project EnergyConnect is implemented.

The 2020 PSFRR identified risks relating to the non-credible separation of South Australia under conditions during which distributed PV generation reduces the net load on Under Frequency Load Shedding (UFLS) circuits, reducing the amount of load that is shed when the UFLS activates, thereby reducing the effectiveness of the scheme. The PSFRR indicated that AEMO intends to seek Reliability Panel declaration of a protected event for non-credible separation of South Australia at certain times, allowing action to be taken whenever the non-credible separation could lead to an under-frequency event that has a material risk of resulting in cascading failure, including stakeholder suggestions for additional options that should be considered for management of the proposed protected event.

We are engaging with AEMO on work for the 2022 PSFRR. From 2023, the PSFRR will be replaced with a broader General Power System Risk Review (GPSRR). We are assessing the impact that this will have on our planning processes.

System security and power quality

We have installed synchronous condensers at Davenport and Robertstown in 2021. The installation of these synchronous condensers addressed the system strength and synchronous inertia needs that AEMO identified in 2018 for South Australia. They also contribute to the ongoing provision of adequate voltage control in the Mid-North and Upper North of the South Australian transmission system including at times of low demand.

Commissioning of the synchronous condensers has allowed the amount of non-synchronous generation that can be dispatched at times of minimum conventional generation in South Australia to be increased from 2,000 MW to 2,500 MW as well as significantly alleviating voltage limits in the Mid North.

AEMO has published the 2020 inertia requirements in South Australia, replacing the 2018 inertia requirements. AEMO has determined the secure operating level of inertia for South Australia, proposing sufficient fast frequency response (FFR) be made available to address the declared inertia shortfall. We have initiated the procurement process and are engaging with the market for the provision of FFR services.

We have identified an emerging need to reduce the system's reliance on dynamic reactive power devices to satisfactorily manage steady-state voltage levels at times of low system demand. The proposed solution is to install a suite of 50-60 Mvar 275 kV reactors at various locations, to maintain an appropriate reserve of dynamic reactive power capability at times of low or negative net system demand.

The changing nature of the power system has impacted overall power quality performance. Ongoing monitoring and supporting studies indicate that mitigation actions may be required at up to four key locations to rectify power quality performance to within compliance limits. This is required to ensure appropriate levels of power quality performance for all network connected customers (load and generation).

Network asset retirements

South Australia's transmission network is older than many others. Our replacement and refurbishment plans are based on our assessment of the condition, risk and performance of the relevant assets. We assess the condition of the various components of each transmission line and substation asset on an ongoing basis through routine inspections and patrols.

This information is used to assess how much longer the component can be expected to keep functioning before it fails. In doing this, we consider other information such as failure rates observed elsewhere and environmental conditions surrounding the assets.

Based on our assessment of asset condition, risk, cost and performance, we plan to address emerging condition needs for a range of assets on South Australia's electricity transmission network during the planning period.

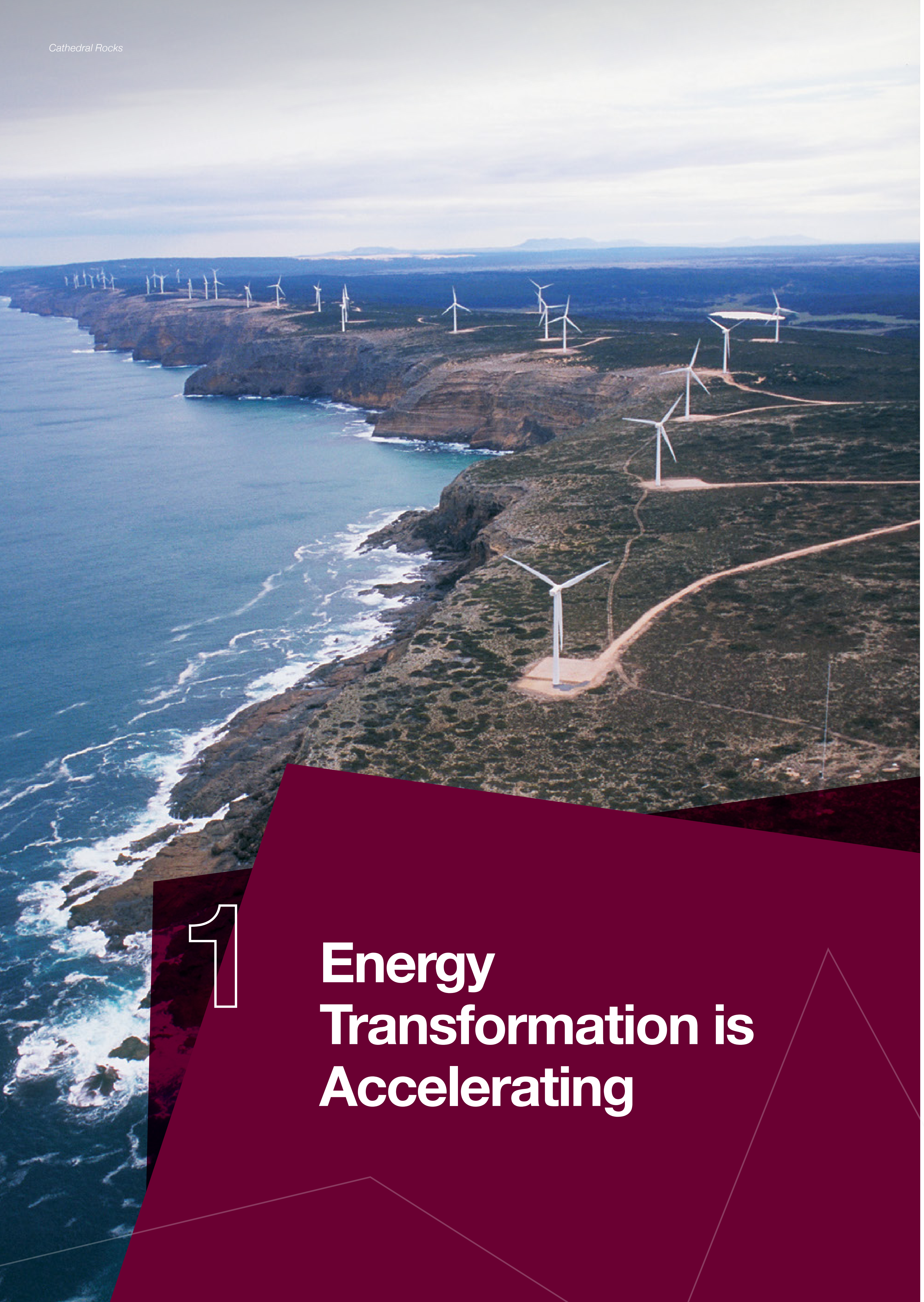
Our major line refurbishment projects and substation asset replacement projects focus on the key components of these assets on the network.

New connections

The South Australian transmission system continues to have capacity to connect new load, generators, and storage. Generation output may at times be limited by system constraints, particularly at times of very low system demand and at times of coincident high generation output of wind and solar farms.

We are aware of significant interest in new generator and load developments, especially in the Mid North, Eyre Peninsula and Riverland regions. We are investigating opportunities to increase transfer capability through the Mid North to allow increased power transfers between these regions and South Australia's load centre in metropolitan Adelaide.

Similarly, we are also investigating ways to further increase the transfer capability between the South East region and the Adelaide metropolitan area, to address potential future interest in the South East as indicated in AEMO's 2020 ISP.



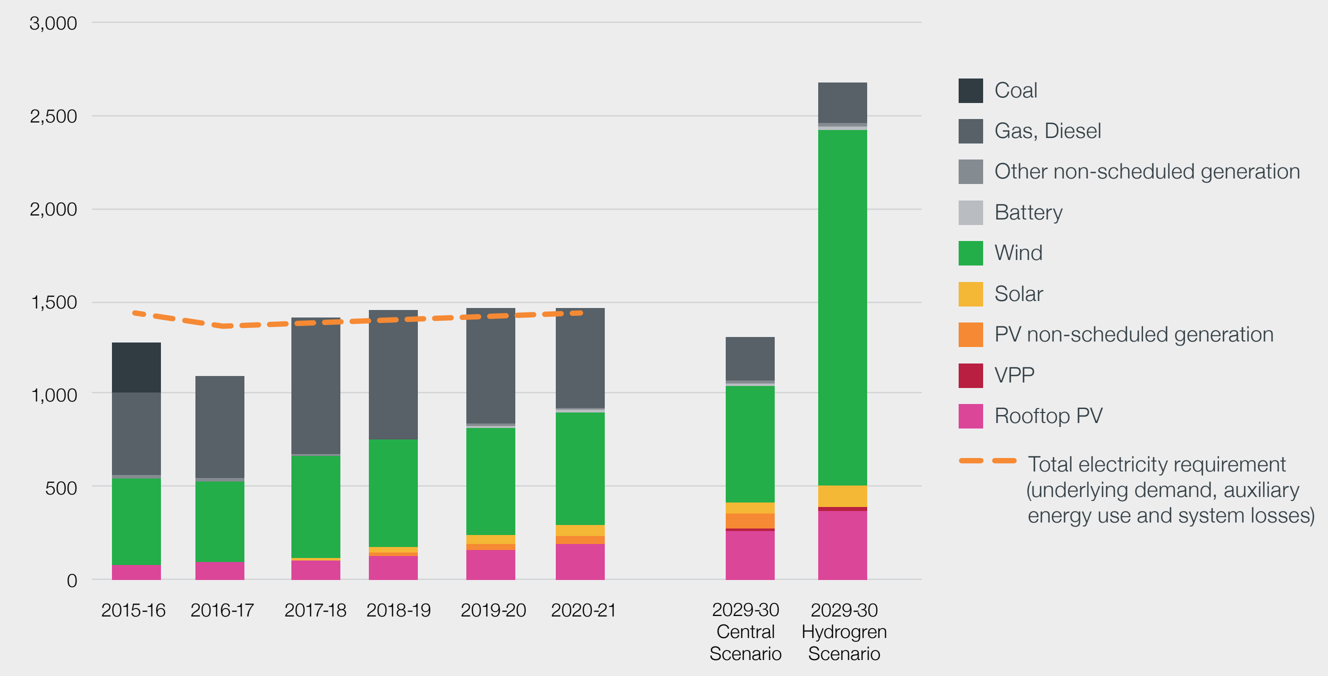
1 Energy Transformation is Accelerating

1.1 South Australia's electricity system is breaking new ground

South Australia remains at the forefront of changes sweeping electricity systems worldwide, with world-leading levels of intermittent renewable energy relative to demand.

Renewable energy sources such as wind, solar, and batteries, and small-scale renewables in homes and businesses, continue to displace thermal generation such as gas. Renewable energy generation is forecast to continue to grow (see figure below), with energy from renewable sources estimated to have supplied about 62% of South Australian electricity demand and generation in 2020-21.

Contributions from South Australian renewable energy generation are forecast to continue to grow



Source: Historical figures up to and including 2019-20 are from the Australian Energy Market Operator's (AEMO's) 2020 South Australian Electricity Report, with the remaining data from AEMO's April 2021 South Australian Generation Forecasts. Figures for 2020-21 represent a mix of AEMO's earlier forecasts and ElectraNet estimates.

Note: The balance between total South Australian generation and electricity demand is made up by net imports or exports across the interconnectors between South Australia and Victoria. Since 2017-18, South Australian electricity exports have slightly exceeded imports.

South Australians have adopted rooftop solar generation faster than anywhere else in the world. Recently, the output of those rooftop systems has exceeded demand in their local area during the day. When this happens, the excess electricity is transported away from the local area to be used by customers elsewhere. This is done using the transmission system. Hence rooftop solar has recently become reliant on the transmission system to export its output.

While it once seemed unlikely that the output of solar systems would exceed local demand, it is an increasingly common experience - we have recorded 'reverse power flows' at more than half of the connection points between our network and SA Power Networks' distribution network.

At the state-wide level, total South Australian demand was completely supplied by South Australian solar generation for the first time on 11 October 2020. This is expected to occur more frequently in the future, with the transmission minimum demand in South Australia forecast to reach zero by 2023, meaning that all demand in the State will be met by distribution connected generators (predominantly rooftop solar PV). Under such conditions, South Australia will be almost entirely reliant on interconnection with the eastern states to balance supply and demand.

Based on the number of active generator connection enquiries and applications we expect that generation from South Australian renewable sources is likely to continue to increase.

These anticipated new connections typically exceed the results of NEM-wide modelling, such has been undertaken by ElectraNet to support the assessment of Regulatory Investment Tests for Transmission (RIT-Ts). This level of interest seems to align with, or may even exceed, the 2020 Integrated System Plan's (ISP's) Step Change scenario.

If new generators continue to connect earlier than previously indicated by generation expansion modelling, plans to strengthen parts of the electricity transmission system may need to be accelerated. At ElectraNet, we are developing plans to enable us to respond in a timely way if this occurs.

1.1.1 Implications of the power system transition

The continued connection of intermittent renewable generation is creating greater variability in electricity generation and demand and is pushing the power system beyond its technical limits. This presents new challenges to reliability, affordability and system security.

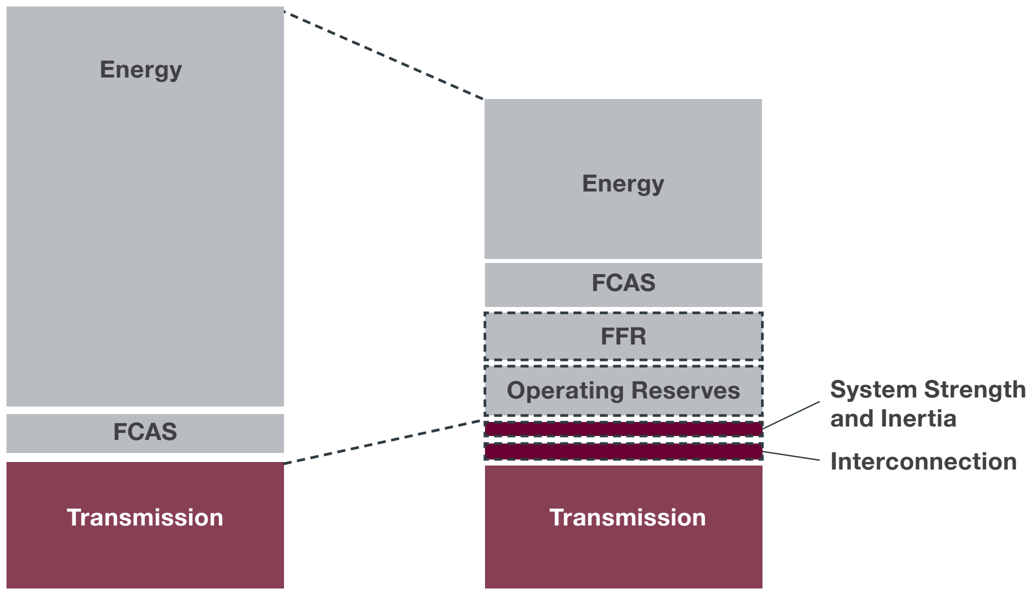
ElectraNet has an increasing role to play in addressing these challenges. While the grid was once used to "deliver" electricity from large remote generators to customers, it is increasingly being used to move electricity back and forth between regions and local areas and to provide essential system services that were once provided by thermal generators.

In 2021 we have installed four synchronous condensers to supply essential system services that are being lost as conventional generators retire and are implementing special protection schemes to protect the power system from disturbances in an increasingly complex operating environment.

With the ever-increasing penetration of intermittent inverter-based generators, we will be called on to provide even more of these services in the future.

Our annual planning process focuses on ensuring system security and reliability of supply. Based on projections of future changes in electricity supply and demand, we seek to forecast limitations and opportunities and ensure plans are in place to address them in a timely and efficient manner.

The evolving role of electricity transmission



FCAS - Frequency Control Ancillary Services
FFR - Fast Frequency Response

1.2 Network Vision, future directions and priorities

We monitor emerging industry trends and technological developments and undertake scenario-based modelling, network planning and assessment of emerging system security issues to inform our ongoing decision making.

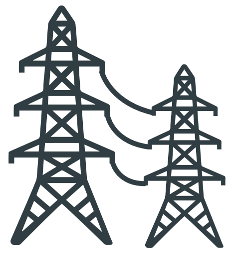
We also engage with customer representatives and other stakeholders to ensure we understand their concerns, needs, priorities and points of view to enhance our ability to plan and develop the transmission network so it delivers the greatest possible value.

Earlier this year we refreshed our Network Vision in consultation with customer representatives and stakeholders. The Network Vision provides directions and key priorities to guide the practical ways we plan for the future of the network, based around four themes.[1]

South Australia's electricity transmission network will support customer choice and deliver affordable and reliable power supplies for a sustainable future.

THEME 1

The network will continue to provide an important role into the future



Maximum Demand

↑158 MW

is forecast to increase by 158 MW to 3,475 MW by 2030.

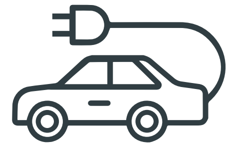
THEME 2

The ongoing uptake of distributed energy resources by customers is changing the role of the network

Rooftop PV

3,700 MW

Rooftop PV to exceed 3,700 MW by 2030.



Electric Vehicles

10%

Electric Vehicles to consume 1,400GWh of energy by 2030 adding more than 10% to demand.

THEME 3

The generation mix is changing creating ongoing challenges for the operation of the grid

Renewables

100% by 2030

Renewables displacing fossil fuels with net 100% renewables targeted by 2030.

Grid Scale Storage

600 MW

Grid scale storage to reach 600 MW by 2030.

THEME 4

New technologies are creating opportunities to change the way network services can be delivered

Virtual Power Plants

420 MW

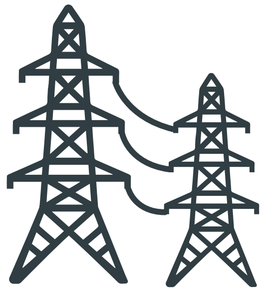
Virtual power plants to reach 420 MW by 2030.

Source: AEMO Integrated System Plan, Step Change Scenario, 2020.

[1] Our 2021 Network Vision is available at https://www.electranet.com.au/what-we-do/network/vision-for-our-network/.

THEME 1

The network will continue to provide an important role into the future



The transmission network will play an increasingly important role in the ongoing transformation of the electricity supply system.

Forecasts over the next ten years point to maximum demand remaining broadly the same. ElectraNet will need to maintain the network's capability to transmit power.

AEMO's ISP highlights the expected retirement of coal generators (this has already happened in South Australia) and their replacement with intermittent generation sources and large-scale storage. It also highlights a greater role for transmission as electricity supply becomes more spread out.

Directions	Priorities	Strategic initiatives, investigations and importance
Affordable electricity remains important to customers **Customers and stakeholders want ongoing and genuine engagement** **The transmission grid will continue to be needed to support economic growth and the transition to a low-carbon future** **New generation investment and supporting transmission investment is already occurring much faster than forecast** **Maximum demand on the grid is not expected to grow, so augmentation investment is expected to be minimal** **Network utilisation will continue to fall, placing ongoing pressure on unit prices** **The age and condition of network assets will be an increasing challenge to manage efficiently** **Evolving market and regulatory frameworks are increasing the role of transmission** **New generation and demand technologies are changing the way the grid responds to system disturbances.**	Deliver cost effective solutions for customers, using scenario-based approaches that consider uncertainty and value flexibility for future decision making	Engage with and support AEMO's ongoing development of the Integrated System Plan (ISP)
	Manage any major and uncertain transmission network investment requirements (e.g. mining loads, renewable energy zones, future system security challenges) as contingent projects within the regulatory framework	We are considering a range of potential contingent projects for inclusion in our 2023-24 to 2027-28 revenue proposal (Appendix E)
	Show leadership in helping to continue to drive down the delivered price of energy	Implement Project EnergyConnect to enable efficient sharing of electricity resources between South Australia and New South Wales (section 7.3)
	Build trust through ongoing genuine engagement with customers and their representatives and other stakeholders	We published our Preliminary Revenue Proposal for 2023-24 to 2027-28 in July 2021, for wide consultation and feedback
	Focus on prolonging asset life and deferring major asset replacement wherever it is efficient to do so while maintaining reliability Maintain network reliability as safely and efficiently as possible through a risk-based Reliability Centred Maintenance approach.	Asset replacement, refurbishment and maintenance needs are determined in accordance with our Strategic Asset Management Plan (Appendix C)

THEME 2

The ongoing uptake of distributed energy resources by customers is changing the role of the network

The transmission network will play an increasingly important role in the ongoing transformation of the electricity The uptake of distributed energy resources in South Australia continues at world leading levels.

South Australia has around 1,600 MW of solar PV connections as of May 2021 and its first day of zero grid demand is forecast for as early as 2023, with increasing need for the transmission system to support residential customers trading power across the NEM. Electrification of transportation is introducing large mobile loads to the grid which may appear as mobile Virtual Power Plants.

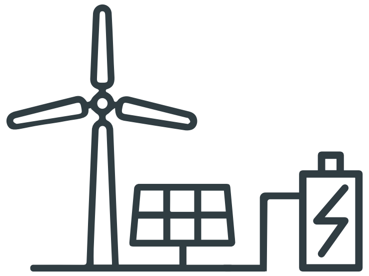
Directions	Priorities	Strategic initiatives, investigations and importance
Demand side participation will play a growing role in the market **Further significant installation of rooftop solar PV capacity will lead to periods of zero grid level demand as soon as 2023** **Small scale energy storage along with advances in data analytics and control will see Virtual Power Plants play an increasing role** **The impact of electric vehicles is expected to be modest over the next ten years, but this could change. With the right incentives, electric vehicle uptake could lead to meaningful levels of distributed and mobile energy storages relatively quickly** **It will continue to be challenging to forecast technology uptake, so scenario planning will be important to consider a range of possible futures** **Managing the impact of distributed energy resources on the secure operation of the power system will be a growing challenge.**	Actively monitor and respond to trends, and expectations to ensure the grid is ready to meet the needs of customers as distributed energy technology is adopted	Continue to liaise with AEMO and SA Power Networks to forecast evolving trends in customer demand and technologies (e.g. rooftop solar PV, household batteries, electric vehicles, hydrogen production, chapter 3) Explore the challenges of the increasing penetration of distributed energy resources, including intermittency/rapid changes, controllability, operation during system events and overall system stability
	Plan for the impacts of customer technologies to maintain safe, reliable, and secure supply under a range of reasonably foreseeable demand and supply conditions	Consider a range of scenarios in our planning and explore generation mix, network developments and technologies to support 100% renewables in SA Develop plans to efficiently accommodate anticipated supply-side changes in an agile manner (section 7.5)
	Actively engage with DER providers to understand capabilities and improve forecasts of uptake	This will help to ensure that identified needs can be addressed at the lowest overall electricity market cost (section 5.6)
	Develop a wide area monitoring system to maintain adequate operation, modelling and control of the changing power system during system disturbances	Enhance high resolution time synchronised wide area system monitoring by pursuing a rollout of the Wide Area Monitoring Scheme (WAMS, section 7.3)
	Increase engagement with SA Power Networks to improve alignment and early identification of emerging network issues.	We have enhanced collaboration by establishing an executive working group to facilitate alignment across the businesses' respective strategies (section B1.6)

THEME 3

The generation mix is changing, creating new challenges for the resilient, secure and reliable operation of the grid

The South Australian power system is changing, with the ongoing withdrawal of traditional synchronous generation sources and continuing investment in renewable wind and solar energy sources and storage. This has led to our investment in synchronous condensers to provide system strength and inertia services and the connection of multiple grid scale batteries.

As the grid continues to evolve with less conventional generation and declining midday demand as well as other changes, operational challenges will increase the need for system security services and new control schemes to manage the secure operation of the power system.



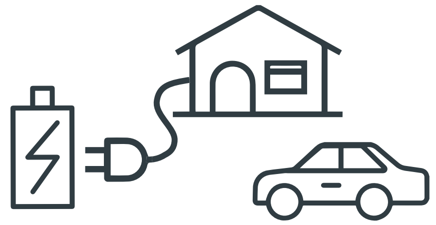
Directions	Priorities	Strategic initiatives, investigations and importance
The ongoing withdrawal of conventional generators and their replacement by intermittent supply sources will place greater reliance on dispatchable generators/ loads, storage and interconnectors **With the changing supply mix the operation of the power system is becoming more complex and challenging** **The South Australian power system is increasingly vulnerable to the risk of islanding through the loss of interconnection** **The risk and potential consequences of state-wide outages after interconnector separation events is very small, but increasing** **The transmission network needs to support the integration of extremely high and growing levels of renewable generation to help maintain secure and reliable electricity supply**	Develop efficient solutions to maintain a secure and reliable network with less conventional generation	Investigate whether forecast potential changes in generator dispatch may give rise to a need for further system strength or frequency control needs
	Deliver Project EnergyConnect to help drive down prices, increase renewable generation exports and reduce the risk of state-wide outages after rare interconnector separation events	We plan for transfer capability across Project EnergyConnect to be progressively released from the end of 2023 (section 7.3)
	Monitor and adopt new technology to maintain secure and reliable power supply at lowest whole-of-system cost to customers, including the expansion and review of protection and control schemes	Enhance the existing System Integrity Protection Scheme to make it a Wide Area Protection Scheme, and consider potential opportunities and benefits of further enhancing the proposed WAPS (section 7.3) Perform a strategic review and replacement of protection schemes (section 7.9)
	Undertake targeted investments to maintain expected levels of power quality	Implement targeted projects to improve local power quality (section 7.4)

THEME 4

New technologies are creating opportunities to change the way network services can be delivered

Rapidly changing technologies are creating both challenges and opportunities for the delivery of transmission services and the evolution of the electricity supply system.

This potentially opens new options to provide network services at lower cost and unlock more capacity to connect new generation and support the transition to a low carbon future.



Directions	Priorities	Strategic initiatives, investigations and importance
The technology and framework for the delivery of essential system services continues to evolve, and transmission is expected to play an increasing role in the delivery of these services **Distributed and grid scale storage technology is likely to become economic in the short term, offering a new potential option to efficiently deliver network and ancillary services** **Ongoing advances in information technology and network control systems provide access to a wealth of 'big data' to inform network decision making** **Technology uptake is advancing at the fastest rate in human history, with customers adopting new technologies at world leading rates** **Market frameworks will continue to develop and adapt to meet the challenges of an evolving energy supply system**	Improve visibility of the behaviour of the grid to ensure the network continues to operate in a safe and efficient manner	Enhance high resolution time synchronised wide area system monitoring by pursuing a rollout of the Wide Area Monitoring Scheme (WAMS, section 7.3)
	Investigate the potential to alleviate existing network limits with the integration of very fast-acting technologies such as grid scale energy storage into the grid	Consider further opportunities for the implementation of innovative technologies, e.g. SmartWires (section 7.6)
	Engage with emerging services providers ahead of the identification of needs to maximise a involvement in option analysis	This will help to ensure that identified needs can be addressed at the lowest overall electricity market cost
	Adopt best-practice data analytics to improve decision making in asset management and network operation	Obtain ISO55001 accreditation
	Explore more efficient and transparent pricing arrangements to reflect asset use, provide clarity and certainty	This would encourage improved utilisation of the transmission system and enable better alignment of supply and demand
	Efficiently deliver new transmission services needed for the safe and reliable operation of the grid such as system strength and inertia	Consider the application of batteries to provide FFR Consider opportunities for future batteries to operate as virtual synchronous generators and provide network support to enhance network transfer capacity

1.3 How are our key priorities helping us prepare for the future?

Driven by our strategic themes, directions and priorities, we are pursuing important initiatives and investigations to support South Australia's ongoing energy transformation.

1.3.1 Interconnection

ElectraNet and TransGrid are partnering to deliver Project EnergyConnect. Project EnergyConnect will involve the construction of a new 330 kV above ground transmission line, with approximately 800 MW transfer capacity. Project EnergyConnect will connect South Australia and New South Wales, with an added connection to north west Victoria.

Project EnergyConnect forms a central feature of the roadmap for the transition of the power system developed by the Australian Energy Market Operator (AEMO) in its 2020 Integrated System Plan (ISP). The ISP classifies Project EnergyConnect as an 'actionable ISP project' which will deliver net market benefits and support energy market transition.

In June 2021, the AER approved Contingent Project Applications from ElectraNet and TransGrid to provide funding for each business to undertake their portion of the works to create Project EnergyConnect.

Project EnergyConnect is expected to deliver a range of direct benefits for consumers in South Australia, New South Wales and Victoria including lower power prices, improved energy security and increased economic activity. The broad route passes through renewable energy zones in South Australia, New South Wales and Victoria, meaning that future renewable projects in these areas will be able to connect to the grid and supply new energy into the network.

We continue to investigate potential opportunities to further improve interconnection transfer capability (section 7.3).

1.3.2 Managing asset condition

South Australia's transmission system is older than many others. Our replacement and refurbishment plans are based on assessment of the condition, risk and performance of the relevant assets (Appendix C). We assess the condition of the various components of each transmission line and substation asset on an ongoing basis through routine inspections and patrols.

This information is used to assess how much longer the component can be expected to keep functioning before it fails. In doing this we consider other information such as failure rates observed elsewhere and environmental conditions surrounding the asset – for example exposure to salt spray from proximity to a coastline.

We then translate this information into a targeted plan to replace and refurbish individual assets before they fail, thus preventing supply interruptions, safety hazards and other risks. These decisions are taken on a risk basis. Rather than replace whole substations, this allows us to focus on those assets at greatest risk.

Consequently, our major line refurbishment projects and substation asset replacement projects focus on the key components of these assets on the network (sections 7.7 and 7.9).

1.3.3 Planning to efficiently accommodate potential supply-side changes

Based on projections in AEMO's 2020 ISP, significant investment in renewable generation within South Australia is expected in the 2030s.

Some significant South Australian dispatchable generation units, such as at Torrens Island A, have been recently retired, and owners of some generation units such as at New Osborne and Torrens Island B unit 1 have indicated that generation withdrawal will occur in the early 2020s. Many dispatchable conventional generators currently have expected withdrawal dates in the mid-2030s.

We continue to investigate options to unlock the network capacity that will be needed to facilitate the connection of the new renewable generation and the retirement of dispatchable conventional generation. We have developed high level scopes for projects that would increase transfer capacity through the Mid North, Eastern Hills and South East regions, improving the ability for generation in those regions to reach our main load centre in metropolitan Adelaide, or be exported via interconnection to other states.

Based on the number of active enquiries and applications, we expect that the amount of South Australian generation coming from renewable sources is likely to continue increasing throughout the 2020s and 2030s. These anticipated connections contrast with the results of NEM-wide generation expansion economic modelling which indicates minimal new connections in South Australia until at least then late 2020s and may even exceed the level of interest indicated in AEMO's 2020 ISP step change scenario.

If new generators do connect more quickly than currently indicated by generation expansion modelling, plans to strengthen parts of the electricity transmission system may need to be accelerated.

We are working on plans that will enable us to respond in a timely way if the projected new developments occur earlier than currently forecast.

1.3.4 System strength and inertia

Given that South Australia has become a world leader in intermittent renewable energy generation penetration levels, traditional synchronous generation sources, such as gas-fired units, now operate less often. This has created an operational challenge to provide ongoing adequate levels of system strength.

We have now installed high-inertia synchronous condensers at Davenport and Robertstown to address system strength and synchronous inertia requirements that were determined by AEMO in October 2017 and December 2018, respectively.

AEMO published 2020 inertia requirements for South Australia, replacing the 2018 inertia requirements. AEMO has determined the secure operating level of inertia for South Australia proposing FFR be made available to address the declared inertia shortfall. We have initiated the procurement process and have engaged with the market for the provision of FFR services.

In October 2021 the AER finalised a new rule that will evolve current system strength framework. The rule introduces a system planning standard for system strength to support the connection of inverter based resources as forecast by AEMO.

The new rule also introduces new access standards for generators and market network service providers and certain loads, including large controllable loads like hydrogen electrolysers. The access standards provide minimum standards relating to short circuit ratio and voltage phase shift angles and provide for the maximum amount of system strength that these connecting parties can demand from the system. This will help to ensure that system strength is used efficiently which reduces overall demand and minimise the costs associated with its supply.

1.3.5 Challenges of increasing penetration of distributed energy resources on system security and voltage control

New technologies are enabling customers to express existing preferences such as increasing their control over their energy costs with their own investments or expressing new preferences such as in the case of an individual seeking to reduce their carbon footprint.

The increasing penetration of rooftop solar PV has seen historically low demand levels recorded in the middle of the day, typically on mild, sunny weekends or public holidays. AEMO forecasts the level of minimum demand in South Australia to continue to decrease over the forecast period (section 3.3).

Low demand conditions at the transmission level can correlate closely with a decreased level of dispatch of large synchronous generators, which have historically been a source of voltage control for the system. When these conditions coincide with periods of low wind, many wind farms are also limited in their ability to contribute reactive power to enable satisfactory voltage control of the system.

We have continued to work with SA Power Networks to jointly analyse the challenges presented by a declining minimum demand, including the impact on system voltage levels. Studies and observations have shown that high voltage levels across the system can occur at such times of extremely low demand.

We have identified a need to invest in several 275 kV switched reactors as minimum demand levels continue to fall, to preserve dynamic control capability on equipment such as SVCs and synchronous condensers (section 7.4). This will maintain the system's capability to ride through unforeseen severe disturbances and prevent voltage levels from exceeding equipment limits during system normal conditions or after an unplanned outage of any single line, transformer, or other network element.

In May 2020, AEMO released a report outlining actions required to ensure the ongoing stability of the South Australian electricity system at high penetration levels of distributed energy resources.[2] We have worked with AEMO to update transfer limits in line with the findings of the report.

The development of Distributed Energy Resources (DER) - as an extension of rooftop solar - and the adoption of more advanced operating capabilities is enabling the development of Virtual Power Plants (VPPs). Over the next ten years, VPPs have the potential to be new providers of services for both ElectraNet and SA Power Networks.

1.3.6 Managing increasing system complexity

The ongoing transformation of the power system is pushing the transmission network to its limits and expanding its role. At the same time, rapidly changing technologies are creating both challenges and opportunities for the delivery of transmission services and the evolution of the electricity supply system.

To increase the transparency of emerging system security risks that may need to be managed, on 3 June 2021 the AEMC made a final determination and final rule to amend the Rules to implement a holistic General Power System Risk Review (GPSRR) that will replace the existing Power System Frequency Risk Review (PSFRR).

The GPSRR is intended to help AEMO, NSPs and other market participants to better understand the nature of new risks and monitor them over time, all of which is particularly important given the transition underway.

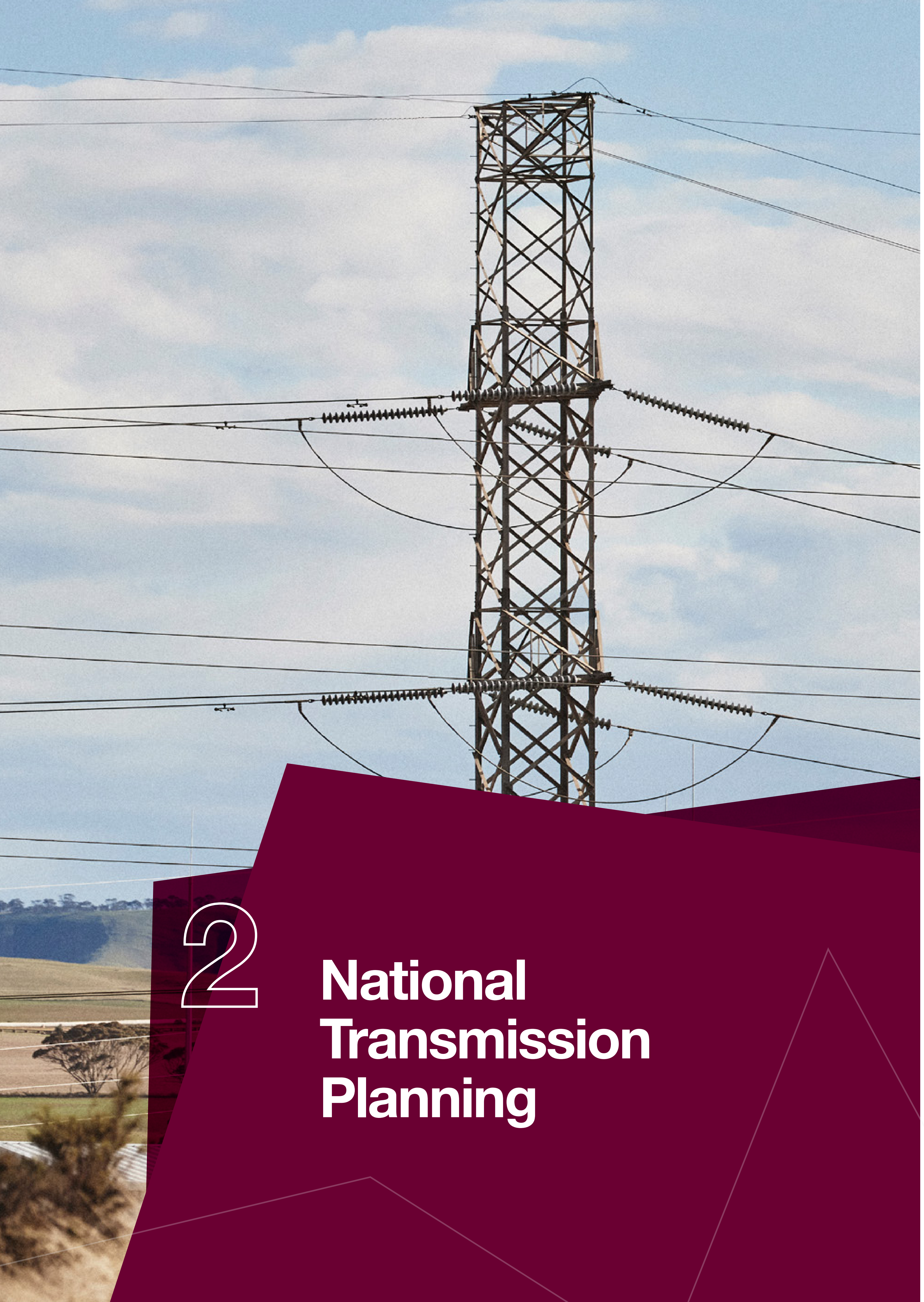
The GPSRR will be an annual review that will require AEMO in collaboration with Network Service Providers to identify and assess risks to power system security that it expects would be likely to lead to cascading outages or major supply disruptions. Risks to be reviewed include:

- non-credible contingency events, the occurrence of which AEMO expects would be likely to involve uncontrolled increased or decreases in frequency, alone or in combination, leading to cascading outages, or major supply disruptions, and
- other events and conditions (including contingency events) the occurrence of which AEMO expects, alone or in combination, would be likely to lead to cascading outages, or major supply disruptions.

To keep pace with the challenges posed by the ongoing transformation of the power system we are planning investments to maintain performance requirements and extend the capabilities of the network, while harnessing the benefits of new and emerging technology. Planned investments include:

- enhance high resolution time synchronised wide area system monitoring by rolling out a Wide Area Monitoring Scheme (WAMS, section 7.3)
- enhance the existing System Integrity Protection Scheme to make it a Wide Area Protection Scheme (section 7.3)
- as part of establishing Project EnergyConnect, implement a Special Protection Scheme to address the risk that a non-credible loss of either Project EnergyConnect or Heywood interconnector would not lead to the loss of the other interconnector.

[2] Minimal operation demand thresholds in South Australia, published May 2020. Available at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/south-australian-advisory-functions.



2 National Transmission Planning

2.1 Integrated System Plan

The 2020 ISP was developed to be an actionable roadmap for the NEM to optimise consumer benefits through a transition period of great complexity and uncertainty. It identified an optimal development path which comprises projects to augment the transmission grid as well as other ISP development opportunities.

The 2020 ISP identified four categories of transmission projects – committed, actionable with decision rules, and future ISP projects. They have been selected from a wide range of options to achieve power system needs through a complex, energy sector transition.

Further major network investments beyond what is currently committed will be needed by 2040, to strengthen the NEM and enable delivery of the identified generation resources. Six major transmission projects have been selected from a large range of credible options and combinations to determine the mix of investments that optimises the net market benefit.

AEMO's economic and power system analysis identified the least-cost development paths for five core scenarios (below). The least-cost development paths for each of the five core scenarios project that the four low-regret projects already being progressed by Transmission Network Service Providers (TNSPs) – VNI Minor, Project EnergyConnect, HumeLink and Central-West Orana REZ Transmission Link – will be completed by 2025-26 at the latest.

If new generators do connect more quickly than currently indicated by generation expansion modelling, plans to strengthen parts of the electricity transmission system may need to be accelerated.

We are working on plans that will enable us to respond in a timely way if the projected new developments occur earlier than currently forecast.

Ideal timing for key national transmission investments under the five core scenarios examined in the 2020 ISP, based on the least-cost development path

<table>
<tr><th>Network project
Scenario/ sensitivity</th><th>VNI Minor</th><th>Central-West Orana</th><th>Project EnergyConnect</th><th>HumeLink</th><th>QNI Medium</th><th>QNI Large</th><th>VNI West</th><th>Marinus Link 1st Cable</th><th>Marinus Link 2nd Cable</th></tr>
<tr><td>Central</td><td rowspan="5">2022-23</td><td rowspan="5">2024-25</td><td>2024-25</td><td>2025-26</td><td>2032-33</td><td>2035-36</td><td>2035-36</td><td>2036-37</td><td>Not needed</td></tr>
<tr><td>Slow Change[3]</td><td colspan="7">No further interconnections needed as this scenario delays the retirement of coal-fired generation and the need for replacement variable renewable energy</td></tr>
<tr><td>Fast Change</td><td rowspan="3">2024-25</td><td rowspan="2">2025-26</td><td rowspan="3">2032-33</td><td rowspan="3">2035-36</td><td rowspan="2">2035-36</td><td>2031-32</td><td>Not needed</td></tr>
<tr><td>Step Change</td><td>2028-29</td><td>2031-32</td></tr>
<tr><td>High DER</td><td>Not needed[4]</td><td>Not needed</td><td>2031-32</td><td>2035-36</td></tr>
</table>

Source: AEMO's 2020 ISP, Table 6.

The following sections provide a short description of the specific 2020 ISP outcomes that relate to the South Australian electricity transmission network.

ElectraNet is working closely with AEMO to support the development of the 2022 ISP.

[3] While HumeLink and Project EnergyConnect are not part of the least-cost development path under the Slow Change scenario under current cost estimates, they are low-regret investments given the relatively low likelihood of this scenario and are therefore included in all candidate development paths.

[4] While HumeLink is not part of the least-cost development path under the High DER scenario under current cost estimates, the majority of the ISP analysis was performed based on a lower cost estimate that resulted in HumeLink still being part of the least cost development path for this scenario. Therefore, any reference to the High DER least cost development path in the remainder of the 2020 ISP report includes HumeLink.

2.1.1 System strength

The 2020 ISP includes the installation of four high-inertia synchronous condensers, previously recommended in the 2018 ISP, as a committed project.

We have now completed the installation of these synchronous condensers at Davenport and Robertstown. The impact that the synchronous condensers have on the amount of non-synchronous generation that can be dispatched in South Australia while meeting system strength limits is described in section 5.3.3.

2.1.2 Project EnergyConnect

The network options AEMO assessed as having the most merit included Project EnergyConnect, which is expected to deliver fuel cost savings and unlock already-stranded renewable investments. Recommended in the 2018 ISP, the 2020 ISP confirmed Project EnergyConnect as a low regret investment.

Section A7.6 in Appendix 7 of the ISP discusses the South Australian system in transition, articulating why Project EnergyConnect will make an important contribution to maintaining system security in South Australia.

The 2020 ISP identified that Project EnergyConnect will support development of the following Renewable Energy Zones (REZs):

- South West New South Wales (New South Wales)
- Murray River (Victoria)
- Riverland (South Australia).[5]

2.1.3 Network expansion to release South East SA REZ capacity

The 2020 ISP forecast that network expansion to release REZ capacity in the South East of South Australia will be needed in the late 2030s, or possibly as early as 2030-31 if the Step Change scenario eventuates.[6]

This network expansion would facilitate the connection of 400 MW to 600 MW of generation within this large REZ, such as wind generation near Mount Gambier or solar generation near Tailem Bend. The proposed scope is to string the vacant Tailem Bend to Tungkillo 275 kV circuit and if necessary install additional dynamic reactive support to enable increased transfers between the South East of South Australia and the Adelaide metropolitan load centre.

The network expansion would also firm up transfer capacity between Heywood Interconnector and the Adelaide metropolitan load centre. The transfer capacity between Heywood Interconnector and the Adelaide metropolitan load centre could otherwise reduce due to the impact of declining average demand in the Eastern Hills region caused by increasing local penetration of distribution-connected solar farms and rooftop solar PV.

Delivery of this network expansion as early as the mid-2020s may be optimal if new generators in the South East or in the Eastern Hills connect earlier than forecast in the 2020 ISP, or if the network expansion can be shown to deliver net market benefits.

High level details of this potential project are provided in sections 2.1.5, 4.4 and 7.5.

2.1.4 Mid North expansion to release REZ capacity in the north of South Australia

The 2020 ISP also forecast the need to alleviate constraints between Davenport and Adelaide and between Davenport and Robertstown in 2034-35 or 2035-36.[7] This would unlock increased capacity to support about 1000 MW of additional hosting capacity for additional wind farms, solar farms and storage north of Adelaide in the Yorke Peninsula, Riverland, Mid North SA, Northern SA and Roxby Downs REZs by increasing transfer capacity between the northern part of the South Australian system and the Adelaide metropolitan load centre.

The network expansion would also firm up transfer capacity between Project EnergyConnect and the Adelaide metropolitan load centre.

We are continuing to investigate the benefits of a project, potentially staged, to deliver increased transfer capacity between Robertstown, Davenport and Adelaide. See sections 2.1.5, 4.4 and 7.5 for high level details about potential project options.

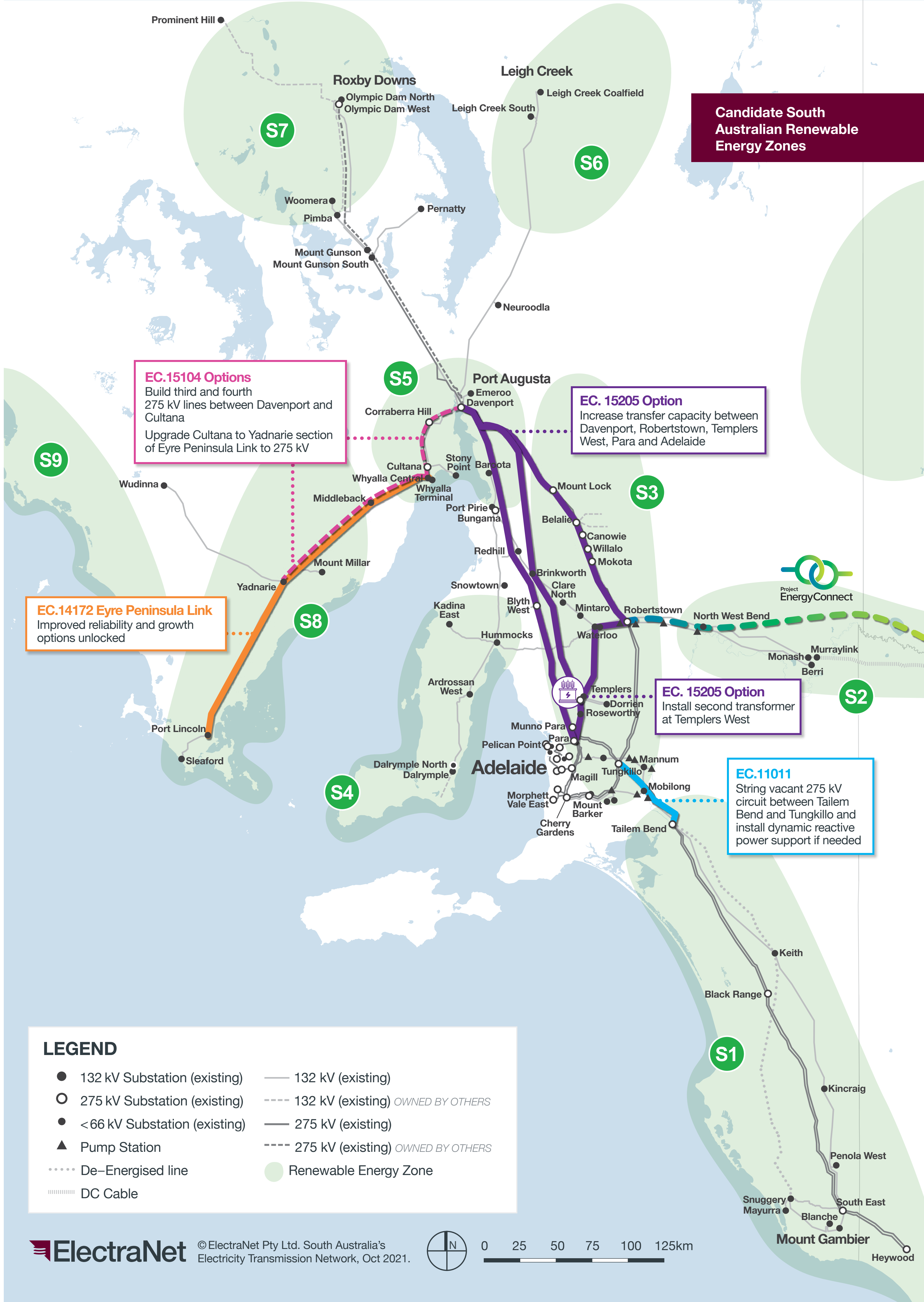
Delivery of increased transfer capacity as early as the mid-2020s may be optimal if new generators or storage facilities north of Adelaide connect earlier than forecast in the 2020 ISP, and if the network expansion can be shown to deliver net market benefits.

2.1.5 Overview of South Australian candidate Renewable Energy Zones

The 2020 ISP identifies nine candidate Renewable Energy Zones in South Australia (right). We have identified potential network investments to release capacity in each of the candidate REZs (right, and overleaf).

The 2020 ISP indicated that most of these South Australian REZs are not forecast to require development within the next 20 years, except for the developments already discussed (sections 2.1.3 and 2.1.4).

Chapter 7 provides more detail about each of the numbered projects such as high-level scope, cost and potential timing.



[5] AEMO's Final 2020 Integrated System Plan, page 17. Available here.
[6] AEMO's Final 2020 Integrated System Plan, page 91. Available here.
[7] AEMO's Final 2020 Integrated System Plan, page 91. Available here.

Potential network investments to release capacity in South Australian Renewable Energy Zones

REZ number	REZ name	Potential network investments
S1	South East SA	Increase transfer capacity between the South East SA REZ and the Adelaide metropolitan load centre by stringing the vacant 275 kV circuit between Tailem Bend and Tungkillo, and installing dynamic reactive support if needed to support increased transfers. We are proposing a contingent project (EC.11011) to deliver this increased capacity if the need arises (Appendix E). Consider increasing transfer capacity between the South East SA REZ and the Melbourne metropolitan load centre by increasing the capacity of the Heywood interconnector, such as by constructing new double circuit 500 kV lines between Heywood and South East.
S2	Riverland	Establish Project EnergyConnect (EC.14171). Establish a new shared connection point at a suitable location along the route of Project EnergyConnect (EC.15201).
S3	Mid-North SA	Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages. We are proposing a contingent project (EC.15205) to deliver this increased capacity if the need arises (Appendix E). Options include: • Installing a second 275/132 kV transformer at Templers West and decommissioning the Templers to Waterloo 132 kV line, to provide an initial increase in transfer capacity between Robertstown in the Mid North and the Adelaide metropolitan load centre • Significantly increasing transfer capacity between Robertstown and Adelaide by building new double circuit 275 kV lines between Robertstown and Templers West, and rebuilding the Templers West to Para 275 kV line as a new double circuit 275 kV line • Significantly increasing transfer capacity between Davenport and Adelaide by building new double circuit 275 kV lines between Davenport and Robertstown, Templers West or Para.
S4	Yorke Peninsula	Establish a new shared connection point that extends the 275 kV network from Blyth West to a suitable location on the Yorke Peninsula.
S5	Northern SA	If new generator developments are to be west of Spencer Gulf, build additional double circuit 275 kV lines between Davenport and Cultana (EC.15261). Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages, as described above for the S3 Mid-North SA REZ.
S6	Leigh Creek	Establish a new shared connection point that extends the 275 kV network from Davenport to a suitable location near Leigh Creek. Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages, as described above for the S3 Mid-North SA REZ.
S7	Roxby Downs	Establish a new shared connection point that extends the 275 kV network from Mount Gunson South or Davenport to a suitable location near Roxby Downs. Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages, as described above for the S3 Mid-North SA REZ.
S8	Eastern Eyre Peninsula	Eyre Peninsula Link (EC.14172) will provide increased capacity to facilitate additional generator connections in the Eastern Eyre Peninsula REZ. Capacity can be further increased by upgrading the operation of the lines between Cultana and Yadnarie from 132 kV to 275 kV and if necessary due to the combined impact of new generator connections in the Eastern Eyre Peninsula REZ, Western Eyre Peninsula REZ and Northern SA REZ west of Spencer Gulf, build additional double circuit 275 kV lines between Davenport and Cultana. We are proposing a contingent project (EC.15104) to deliver this increased capacity if the need arises (Appendix E). Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages, as described above for the S3 Mid-North SA REZ.
S9	Western Eyre Peninsula	Eyre Peninsula Link (EC.14172) will provide increased capacity to facilitate additional generator connections in the Western Eyre Peninsula REZ. Capacity can be further increased by upgrading the operation of the lines between Cultana and Yadnarie from 132 kV to 275 kV and if necessary due to the combined impact of new generator connections in the Eastern Eyre Peninsula REZ, Western Eyre Peninsula REZ and Northern SA REZ west of Spencer Gulf, build additional double circuit 275 kV lines between Davenport and Cultana. We are proposing a contingent project (EC.15104) to deliver this increased capacity if the need arises (Appendix E). Establish a new shared connection point that extends the 132 kV or 275 kV network from Yadnarie to a new suitable location on the western Eyre Peninsula. Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages, as described above for the S3 Mid-North SA REZ.

Robertstown Substation

2.2 Power System Frequency Risk Review

AEMO undertook the Power System Frequency Risk Review (PSFRR) for 2021 and published reports in two stages. AEMO published a Stage 1 report in July 2020 to provide high level recommendations for each jurisdiction, with further details published in the final (Stage 2) report in December 2020.

2.2.1 Recommendations for South Australia

AEMO identified that continued growth in DER is likely to see a net load reduction in distribution feeders, with more distribution feeders feeding power back into the transmission network during the middle of sunny days. To ensure the effectiveness of Under Frequency Load Shedding (UFLS) schemes, AEMO recommended that all transmission and distribution network service providers review the design of existing UFLS schemes (section 4.5.1).

AEMO also recommended that ElectraNet, in collaboration with AEMO, continue to work on enhancements to South Australia's System Integrity Protection Scheme (SIPS) by implementing a Wide Area Protection Scheme (WAPS), with the final scheme expected to be commissioned by October 2022 (section 4.5.3).

AEMO identified a need to manage reduced effectiveness of UFLS in periods with low load or high distributed PV generation to control frequency following the non-credible loss of interconnection between South Australia and Victoria when South Australia is importing power from Victoria. AEMO indicated an intention to make a submission to the Reliability Panel, seeking for the non-credible synchronous separation of South Australia from the rest of the NEM to be considered a protected event under certain conditions.

AEMO indicated that work was being undertaken by ElectraNet and AEMO to reassess power system operational limits that will apply following the commissioning of the four synchronous condensers that we have now installed at Davenport and Robertstown, with a view to updating planning assumptions once the synchronous condensers were commissioned. This work has now been completed.

AEMO reviewed the South Australian Over Frequency Generation Shedding (OFGS) scheme, and recommended that AEMO work in consultation with ElectraNet to review the effectiveness of the OFGS and modify it if required (section 4.5.2).

2.3 General Power System Risk Review

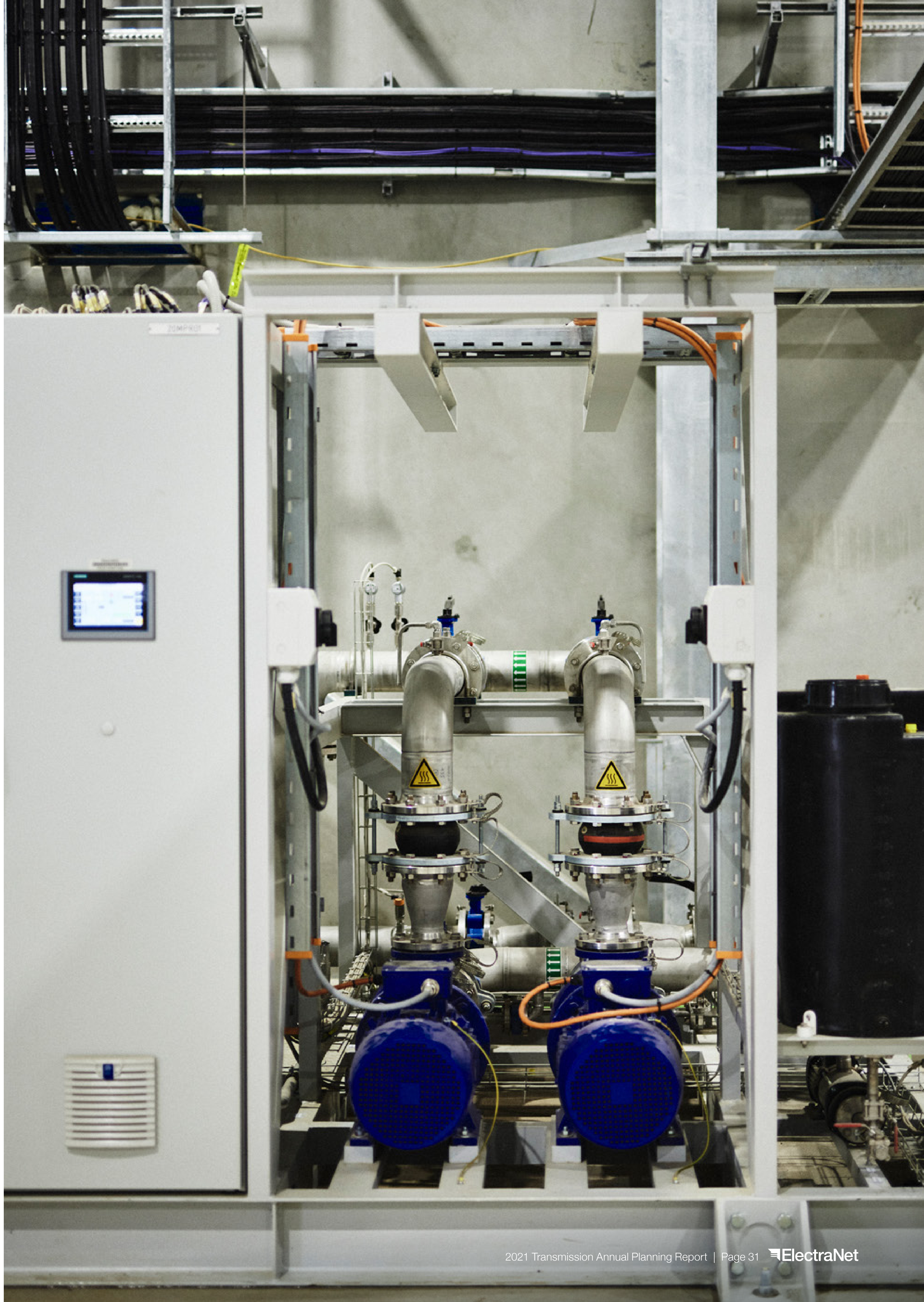
On 3 June 2021 the AEMC made a final determination and final rule to amend the Rules to implement a holistic General Power System Risk Review (GPSRR) that will replace the existing Power System Frequency Risk Review (PSFRR).

The GPSRR is intended to help AEMO, NSPs and other market participants to better understand the nature of new risks and monitor them over time, all of which is particularly important given the transition underway.

The GPSRR will be an annual review that will require AEMO in collaboration with Network Service Providers to identify and assess risks to power system security that it expects would be likely to lead to cascading outages or major supply disruptions. Risks to be reviewed include:

- Non-credible contingency events, the occurrence of which AEMO expects would be likely to involve uncontrolled increases or decreases in frequency, alone or in combination, leading to cascading outages, or major supply disruptions, and
- Other events and conditions (including contingency events) the occurrence of which AEMO expects, alone or in combination, would be likely to lead to cascading outages, or major supply disruptions.

The first GPSRR is to be completed by 31 July 2023.



3 Electricity Demand

Electricity demand forecasts are a key input to ensuring the transmission network continues to deliver the services customers expect.

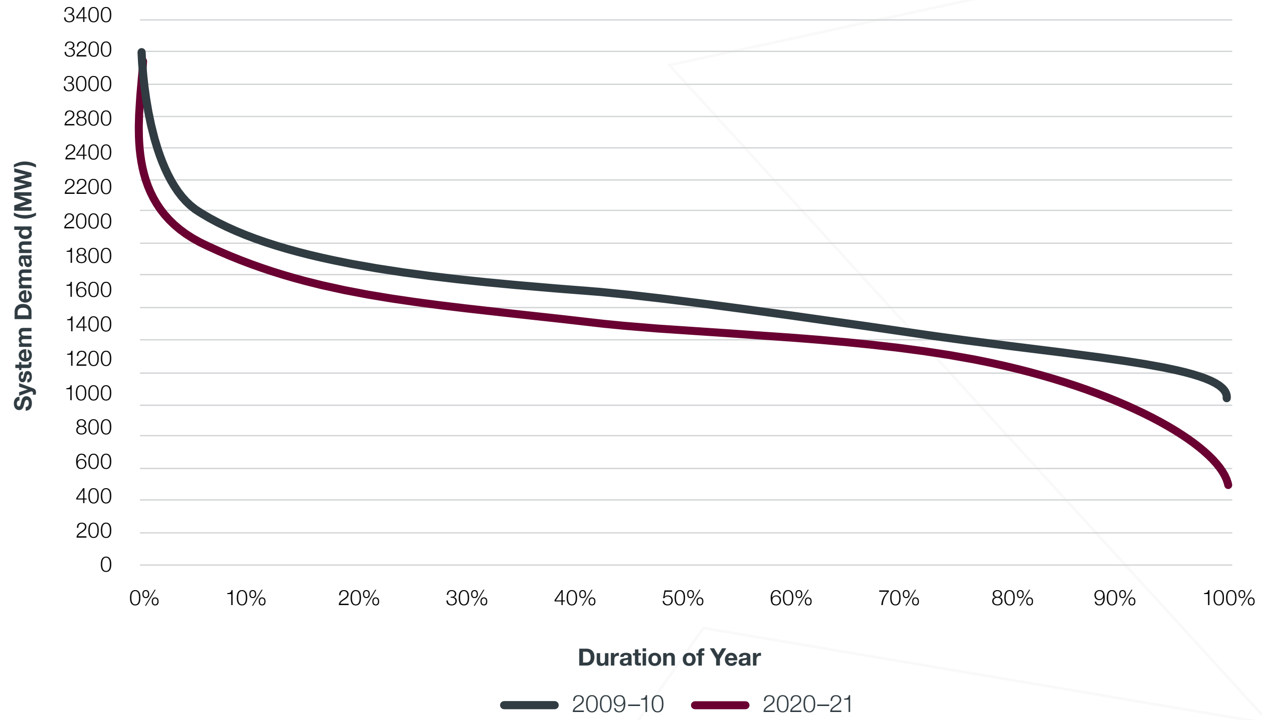
Each registered participant connected to the transmission network is required to provide demand forecast information on an annual basis according to Schedule 5.7 of the National Electricity Rules (Rules). ElectraNet uses this information and observed data to forecast electricity demand.

3.1 South Australian electricity demand

The South Australian load profile is very 'peaky' in nature with relatively low energy content (figure below). This means that even though demand can exceed 3000 MW on hot summer days, demands between 1000 and 2000 MW are most common throughout the year. The continued uptake of embedded solar PV in recent years has significantly lowered demand supplied by the transmission system during the day, especially on weekends and public holidays.

Minimum demand on the South Australian electricity system has approximately halved from 2009-10 to 2020-21. We expect that the continuing uptake of embedded solar PV will produce even lower minimum demands.

South Australian system wide load duration curves for 2009-10 and 2020-21



Note the very small percentage of time that demands above 2,000 MW are present on the South Australian transmission network, and the increasing percentage of time that demands below 1,000 MW are present. Maximum demands have remained at a similar level, whereas demand levels at other times and particularly at times of minimum demand have reduced from 2009-10 to 2020-21.

3.2 Demand forecasting methodology

ElectraNet annually receives 10-year demand forecasts from SA Power Networks and direct connect customers.

A description of the load forecasting process used by SA Power Networks is provided in SA Power Networks' 2020 Distribution Annual Planning Report.[8] ElectraNet and SA Power Networks collaborate 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 were based on the connection point maximum demand forecasts that were provided by SA Power Networks in October 2020. We have reviewed the latest connection point maximum demand forecasts provided by SA Power Networks in September 2021 and determined that the development plans remain appropriate. Details of the latest connection point forecasts can be found on ElectraNet's Transmission Annual Planning Report webpage.[9]

In August 2021, AEMO produced and published forecasts of energy, maximum demand and minimum demand for South Australia to support the 2021 *Electricity Statement of Opportunities* (ESOO).[10] ElectraNet has considered those forecasts to determine future needs for improved voltage control on the 275 kV Main Grid at times of minimum demand in South Australia.

AEMO also publishes 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.[11]

ElectraNet compares its forecasts (as published on the Transmission Annual Planning Report webpage)[12] against AEMO's forecasts. At an aggregate level, AEMO's and ElectraNet's connection point forecasts are both reconciled to AEMO's State-level forecast from the 2021 ESOO 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 material impact on network limitations or development plans within the next 10 years.

ElectraNet uses both the AEMO state-wide forecasts and our own connection point forecasts depending on the needs of a particular planning study.

3.3 Demand forecasts

In most cases there is very little change in the projections of future demand for connection points compared to the demand forecast which was used as the basis for the plans presented in the 2020 Transmission Annual Planning Report. Our plans for individual connection points have not needed to be updated.

AEMO makes state-wide demand forecasts for South Australia available on its Forecasting Data Portal.[13]

The most recent update to AEMO's South Australian State-wide forecasts was published in August 2021, alongside AEMO's 2021 ESOO.

We have compared AEMO's August 2021 ESOO central forecasts for South Australian maximum and minimum demand to the 2020 ESOO forecasts that formed the basis of the plans presented in the 2020 Transmission Annual Planning Report, along with the previous ten years and current year of actual maximum, average and minimum demands (below). While forecast maximum and average demands remains similar, the 2021 minimum demand forecast is significantly lower and steeper than the 2020 minimum demand forecast.

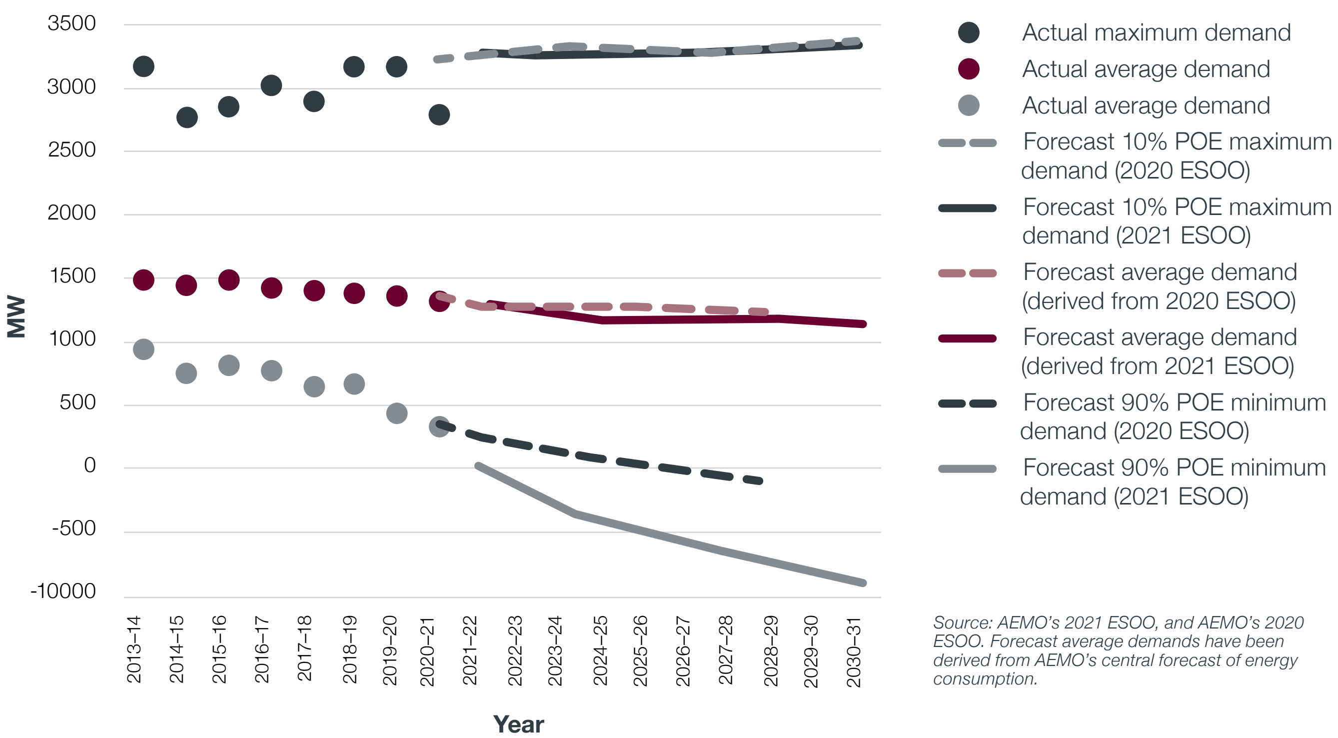
3.3.1 Potential key drivers of demand

The figure below shows maximum demands are forecast to increase only slightly in coming years. There are, however, several potential developments that could, if they occur, drive a significant increase in maximum demands. These include:

- The potential connection of new large customer loads such as new or expanded mines, new large industrial loads, or other energy-intensive opportunities such as the production of "green steel"
- The development of large hydrogen hubs in accordance with the South Australian Government's hydrogen strategy
- The widespread adoption of electric vehicles or the electrification of appliances or sectors that currently utilise other fuel sources.

The figure below also shows that minimum demands are forecast to decrease steeply in coming years. This trend is driven by forecast continued rapid uptake by customers of rooftop solar PV.

AEMO's 2021 ESOO central and 2020 ESOO central forecasts



Source: AEMO's 2021 ESOO, and AEMO's 2020 ESOO. Forecast average demands have been derived from AEMO's central forecast of energy consumption.

[8] *Available from sapowernetworks.com.au/industry/annual-network-plans.*
[9] *Available from www.electranet.com.au/what-we-do/network/regulated-network-reports-and-studies.*
[10] *Available from aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.*
[11] *Available from aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/ Transmission-Connection-Point-Forecasting.*
[12] *Available from www.electranet.com.au/what-we-do/network/regulated-network-reports-and-studies.*
[13] *Accessible at http://forecasting.aemo.com.au/.*

3.4 Performance of 2020 demand forecasts

3.4.1 Weather conditions during summer

Weather conditions over summer are a key driver of maximum demand for electricity in South Australia. 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.

Weekends, public holidays, and the holiday period that begins at Christmas time and extends until Australia Day reduce the impact of high temperatures on demand. For state-wide electricity demand to reach high levels, metropolitan Adelaide needs to experience high temperatures, generally on working days outside of the holiday period.

Individual connection points, however, can 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 time in wine regions).

November 2020-21 recorded daily maximum temperatures that were, on average, significantly warmer than the long-term trends for that month. Other months recorded daily maximum temperatures that were roughly in line with their long-term trends; however, the maximum recorded temperature in each month was well below the historical extremes. The highest recorded temperature at the Bureau's official Adelaide city site at West Terrace was 42.7 °C on Sunday 24 January (below).

2020-21 Summer temperature data compared with long term trends

	November		December		January		February		March	
	Long-term trend	2020-21	Long-term trend	2020-21	Long-term trend	2020-21	Long-term trend	2020-21	Long-term trend	2020-21
Max temp (°C)	42.7	40.6	45.2	37.3	46.6	42.7	43.4	37.9	41.8	32.6
Date of max temp	30-Nov 1962	27-Nov 2020	19-Dec 2019	14-Dec 2020	24-Jan 2019	24-Jan 2021	1-Feb 1912	17-Feb 2021	3-Mar 1942	20-Mar 2021
Average max temp (°C)	24.5	28.8	26.9	26.3	28.6	28.9	28.5	27.1	26.0	26.0
Days[14] >30°C	6.1	15	9.1	6	11.7	13	10.7	9	7	5
Days[14] >35°C	1.6	6	3.8	3	5.5	4	4.4	4	1.6	0
Days[14] >40°C	0.1	1	0.6	0	1.1	1	0.6	0	0.1	0
Difference between 2020-21 average max temp and long-term trend	4.3		-0.6		0.3		-1.4		0.0	

Source: Bureau of Meteorology, Adelaide (West Terrace/ngayirdaripira)

3.4.2 State-wide demand review

State-wide demand during 2020-21 reached a maximum of 2,742 MW on Thursday 18 February 2021. Demand exceeded 2,500 MW on four days during the 2020-21 summer (table below).

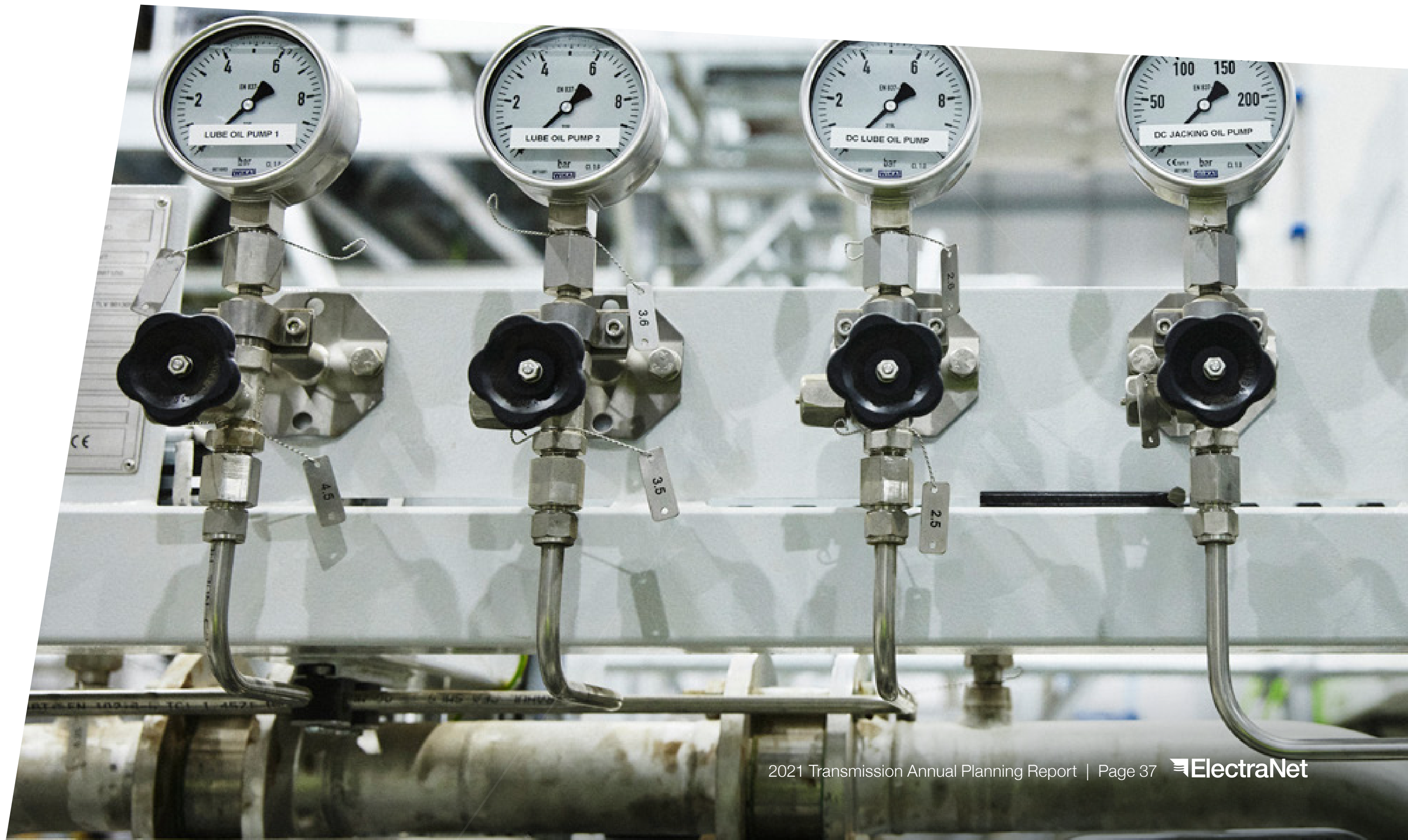
Highest demand days in summer 2020-21

Date	Maximum demand (MW)[15]	Maximum temperature (°C)	Preceding overnight minimum temperature (°C)	Preceding day maximum temperature (°C)
Thursday 18 February 2021	2,742	36.9	26.9	36.7
Sunday 24 January 2021	2,650	42.7	27.0	34.0
Wednesday 17 February 2021	2,606	37.9	22.4	36.9
Friday 27 November 2020	2,589	40.6	19.4	33.3

Temperature patterns with the potential to deliver very high demand levels are typically characterised by very high Adelaide maximum temperatures on the day and preceding day of 40 °C or more, combined with a high preceding overnight minimum temperature of about 25 °C or higher.

Demand levels corresponding to a 10% Probability of Exceedance (POE) typically occur if such weather conditions occur mid-week, before or after the traditional holiday period between Christmas Day and Australia Day. Such temperature patterns did not occur during the 2020-21 summer, consistent with the relatively subdued maximum demand levels that were recorded during the 2020-21 summer.

Results at individual connection points are expected to vary due to local conditions. However, given that state-wide maximum demand was subdued, connection point maximum demands can be expected, on average, to also be low compared to expectations (section 3.4.3).



[14] Mean days for long term trend data, actual days for 2020-21 data

[15] These values represent the Operational Demand of the South Australian electricity system. Operational Demand excludes demand supplied by small non-scheduled generation and other exempt generation such as rooftop solar, gas tri-generation, very small wind farms. Source: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/aggregated-data.

Minimum demands were below 400 MW on 23 days between 1 October 2020 and 30 September 2021 (table below).

Lowest demand days from 1 October 2020 to 30 September 2021

Date	Minimum demand (MW)[16]	Maximum temperature (°C)	Preceding overnight minimum temperature (°C)	Preceding day maximum temperature (°C)
Saturday 10 October 2020	346	21.2	12.6	20.4
Sunday 11 October 2020	289	24.0	7.3	21.2
Sunday 1 November 2020	312	25.9	7.0	18.2
Saturday 7 November 2020	288	23.2	10.7	18.1
Sunday 8 November 2020	336	28.0	12.7	23.2
Saturday 14 November 2020	335	30.1	11.5	19.8
Sunday 29 November 2020	388	23.5	13.8	33.3
Saturday 19 December 2020	330	24.6	10.7	20.9
Sunday 20 December 2020	380	29.7	11.5	24.6
Friday 25 December 2020	285	29.6	13.6	26.7
Monday 28 December 2020	258	20.9	9.2	26.0
Tuesday 29 December 2020	370	22.8	10.1	20.9
Sunday 3 January 2021	387	26.1	17.1	25.3
Tuesday 5 January 2021	370	22.4	13.8	21.4
Saturday 16 January 2021	370	22.2	14.3	21.3
Monday 8 February 2021	380	25.7	13.0	21.2
Sunday 14 February 2021	291	26.3	12.3	23.5
Monday 8 March 2021	357	26.4	16.5	28.5
Sunday 14 March 2021	353	20.6	9.7	20.8
Saturday 14 August 2021	371	17.8	5.9	16.9
Saturday 21 August 2021	384	18.0	8.9	18.6
Sunday 19 September 2021	364	20.0	7.8	17.1
Sunday 26 September 2021	199	19.6	9.1	17.6

Very low demand levels are typically characterised by mild Adelaide maximum temperatures between about 20 °C and 30 °C on a sunny day, preceded by a cool to mild overnight minimum temperature between about 5 °C and 15 °C. The lowest demand levels occur when these conditions coincide with a weekend or public holiday.

Overall, weather conditions that drive very low demands are more common and can occur throughout a longer period of the year, than weather conditions that drive very high demands.

3.4.3 Connection point maximum demand 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 2020-21, North West Bend was the only bulk supply connection point that recorded maximum demands that exceeded its forecast 10% POE maximum demand between 1 December 2020 and 31 March 2021 (table top next page). North West Bend connection point was still operating within its capability.

[16] These values represent the Operational Demand of the South Australian electricity system. Operational Demand excludes demand supplied by small non-scheduled generation and other exempt generation such as rooftop solar, gas tri-generation, very small wind farms. Source: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/aggregated-data..

Recorded maximum demands more than 100% of 10% POE demand forecast in summer 2020-21

Connection point	ElectraNet 10% POE forecast (MW)	AEMO 10% POE forecast (MW)	Actual Maximum (MW)	Actual demand as a percentage of ElectraNet 10% POE forecast (%)	Date and time of maximum demand (Market time)
North West Bend	24.0	21.7	25.5	106%	23 January 2021 19:00

The four metropolitan bulk connection points each recorded maximum demands that were significantly lower than their 10% POE forecast. Two small (less than 2 MW) and 19 medium connection points failed to reach 85% of their 10% POE forecast (table below). This high number of connection points with a maximum demand that was significantly below the 10% POE forecast level is consistent with the expectation that connection point maximum demands, on average, would be subdued along with the subdued state-wide maximum demand (section 3.4.2).

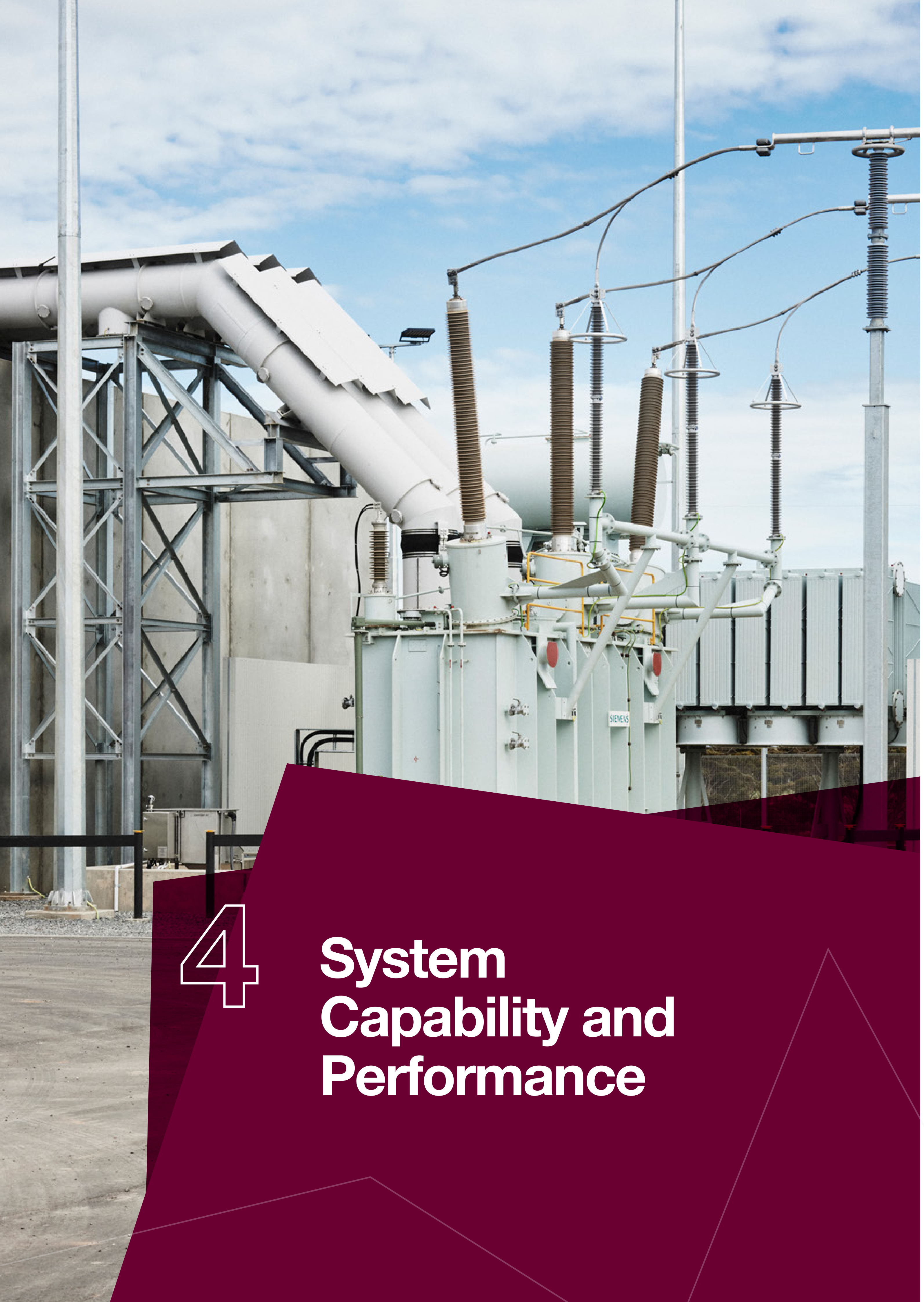
The 2021 review of connection point forecasts considered the impact of measured maximum demands from summer 2020-21. The September 2021 connection point forecasts are available in the connection point information published on our Transmission Annual Planning Report webpage.[17]

Recorded maximum demands either lower than the 10% POE demand forecast by at least 20 MW, or lower than 85% of 10% POE demand forecast, in summer 2020-21

Connection point[18]	ElectraNet 10% POE forecast (MW)	AEMO 10% POE forecast (MW)	Actual Maximum (MW)	Actual demand as a percentage of ElectraNet 10% POE forecast (%)	Date and time of maximum demand (Market time)
Northern suburbs	355.2	299.7	306.4	86%	18/02/2021 18:30
Yadnarie	8.0	8.1	6.8	84%	18/02/2021 19:00
Bungama and Port Pirie	65.3	63.3	55.0	84%	24/01/2021 17:30
Port Lincoln	32.7	31.7	27.5	84%	24/01/2021 19:00
Brinkworth	5.1	5.1	4.3	84%	24/01/2021 18:00
Playford	31.6	34.6	26.1	83%	24/01/2021 18:00
Clare North	12.5	13.9	10.3	82%	24/01/2021 18:00
Dorrien	62.1	58.5	51.2	82%	18/02/2021 18:30
Wudinna	16.2	15.6	13.3	82%	18/02/2021 19:00
Mobilong	38.2	39.7	31.4	82%	17/02/2021 18:30
Southern suburbs	717.0	665.9	583.6	81%	18/02/2021 18:30
Waterloo	9.8	9.6	7.9	81%	24/01/2021 18:30
Mt Barker	103.4	97.2	82.8	80%	24/01/2021 18:30
Kanmantoo	1.8	1.5	1.4	79%	17/02/2021 19:00
Templers	34.3	31.1	27.1	79%	17/02/2021 19:00
Western suburbs	453.4	444.5	357.4	79%	18/02/2021 18:30
Eastern suburbs	750.3	737.4	576.4	77%	18/02/2021 18:00
Kadina East	29.9	27.5	22.9	77%	24/01/2021 18:00
Hummocks	15.0	14.2	11.4	76%	24/01/2021 18:30
Angas Creek	20.4	20.6	15.5	76%	24/01/2021 18:30
Kincraig	23.3	21.0	17.6	75%	24/01/2021 18:30
Baroota	8.8	9.1	6.5	74%	24/01/2021 19:00
Keith	24.5	23.8	18.0	74%	10/01/2021 19:00
Neuroodla	1.0	0.9	0.7	71%	23/01/2021 18:30

[17] Available from www.electranet.com.au/what-we-do/network/regulated-network-reports-and-studies

[18] Low-demand connection points where the actual demand was within 0.1 MW of the 10% POE forecast have not been included.



4 System Capability and Performance

4.1 The South Australian electricity transmission system

The South Australian transmission network is one of the most extensive regional transmission systems in Australia, extending across some 200,000 square kilometres of the State. This network consists of transmission lines operating at 132,000 and 275,000 Volts, which are supported by both lattice towers and large stobie poles. It connects the major South Australian load centres with various sources of generation (map overleaf).

The Main Grid is a meshed 275 kV network that extends from Cultana substation (near Whyalla) to South East substation (near Mount Gambier). The Main Grid overlays regional networks that cover seven regions: Metropolitan, Eastern Hills, Mid North, Riverland, South East, Eyre Peninsula and Upper North.

The South Australian transmission system is relatively skinny and long, which can make it challenging to enable significant power transfers through the system while ensuring appropriate levels of stability and voltage. The section between South East and Adelaide has been series compensated to manage some of these challenges.

Most base and intermediate conventional generators are gas-fired and located in the Adelaide metropolitan area, while peaking power stations are spread throughout the state.

Since the retirement of Northern Power Station in 2016, there are no coal fired generators in South Australia. The significant uptake of renewables and resulting reduced dispatch of conventional generation has resulted in emerging system security challenges such as the need to actively manage levels of system inertia and system strength. Synchronous condensers were installed at Davenport and Robertstown in 2021 to maintain required levels of system inertia and system strength (section 6.1).

South Australia also currently has two interconnectors that connect South Australia to the Victorian region of the NEM: the Heywood HVAC interconnector (established in 1989) in the state's South East, and the Murraylink HVDC interconnector (established in 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. In recent times, due to the high penetration of renewable generation in South Australia, surplus generation is often exported through the two interconnectors.

Interconnector transfer capacity has increased to 600 MW (import) and 550 MW (export) since the upgrade to the Heywood interconnector was completed in mid-2016. The combined maximum transfer capacity between South Australia and Victoria under normal conditions is now about 820 MW[19] for imports to South Australia, and 700 MW[20] for exports.[21]

Emergency control schemes such as under frequency load shedding (UFLS), over frequency generator shedding (OFGS) and the System Integrity Protection Scheme (SIPS) are in place to manage system security for significant events and enable higher transfers across the interconnectors under normal conditions than if the schemes were not in place.

4.1.1 Designated network assets

ElectraNet is required to report on designated network assets in South Australia.

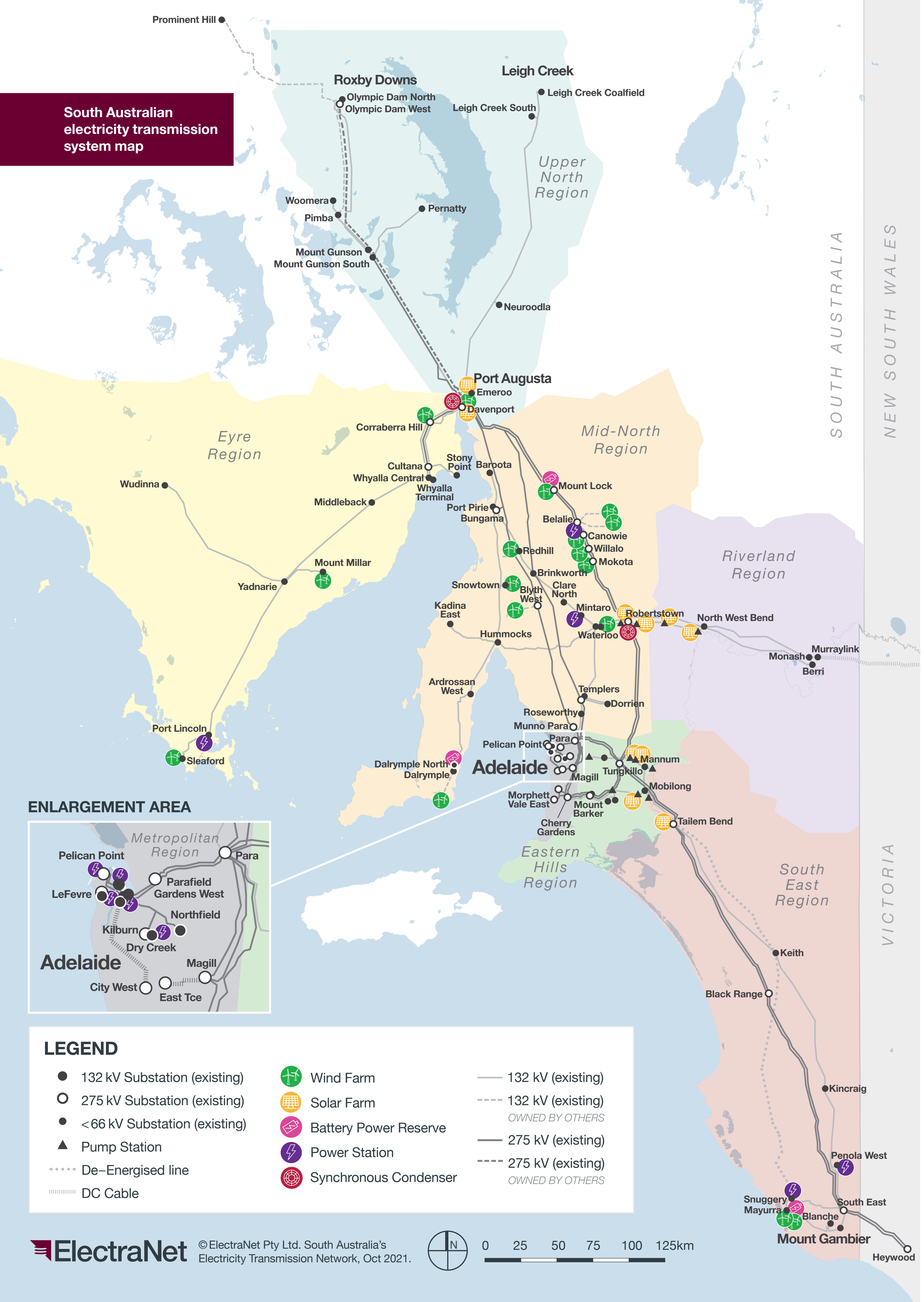
Designated network assets are defined in the Rules. They are apparatus, equipment, plant and buildings that are used from a "boundary point" to convey electricity for an identified user group and are owned by a member or members of that identified user group. They do not provide prescribed transmission services, form part of a network loop, form part of a transmission system for which a Market Network Service Provider is registered under Chapter 2 of the Rules, or form part of a declared transmission system of an adoptive jurisdiction.

There are currently no designated network assets within South Australia.

[19] Consisting of 600 MW import through Heywood interconnector and 220 MW import through Murraylink interconnector.

[20] Consisting of 550 MW export through Heywood interconnector and 150 MW export through Murraylink interconnector (constrained by typical voltage limits in the Riverland).

[21] At the time of publication, transfer capability is restricted to lower levels due to the outage of one Para SVC.



4.2 Transmission system constraints in 2020

AEMO uses constraint equations to manage system security and market pricing. When a constraint binds on dispatch 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.

We have assessed network constraints that had a binding impact on transmission network and interconnector flows of greater than $50,000 during the 2020 calendar year (table below). Some constraints have been grouped as they manage the same network limit or operating condition. For example, two constraints might both manage the overload of the same network element for different contingency events.

Constraint equations, descriptions and impact in 2020

Network limitation	Binding impact (2020)	Binding hours (2020)	Proposed and implemented actions
S_WIND_1200_AUTO & S_NIL_STRENGTH_1 Upper limit (1,300 to 1,750 MW) for South Australian non-synchronous generation for minimum synchronous generators online for system strength requirements	$11,147,928	942.3	S_NIL_STRENGTH_1 replaced the constraint S_WIND_1200_AUTO. The installation of synchronous condensers at Davenport and Robertstown in 2021 has reduced the impact of this constraint by raising the level at which it is expected to bind to 2,500 MW
S>NIL_MHNW1_MHNW2 Avoid an overload of Monash-North West Bend 132 kV line No. 2 if a trip of Monash – North West Bend 132 kV line No.1 was to occur	$596,844	144.0	The North West Bend to Monash No. 2 132 kV line has been uprated from 80°C to 100°C ratings. Murraylink control upgrades to operationally implement the increased ratings occurred in October 2020, alleviating this constraint.
S>NIL_NIL_NWMH2 Avoid an overload of North West Bend – Monash 132 kV line No. 2 during system normal conditions	$408,654	10.3	The North West Bend to Monash No. 2 132 kV line was uprated from 80°C to 100°C ratings. Murraylink control upgrades to operationally implement the increased ratings occurred in October 2020, alleviating this constraint.
S>NIL_HUWT_STBG2 Limit Snowtown wind farm generation output to avoid Snowtown – Bungama 132 kV line overloading if a trip of the Hummocks – Waterloo 132 kV line was to occur	$383,879	42.3	We are monitoring this constraint to determine if options such as automatic runback control schemes for 132 kV wind farms in the Mid North are likely to alleviate this constraint.
S>V_NIL_NIL_RBNW Avoid overloading Robertstown – North West Bend No. 1 or No. 2 132 kV lines during system normal conditions	$271,092	285.8	The Robertstown to North West Bend No. 2 132 kV line was uprated from 80°C to 100°C ratings in May 2019. Murraylink control upgrades to operationally implement the increased ratings occurred in October 2020, alleviating this constraint.
S>NIL_BWMP_HUWT Avoid an overload of the Hummocks – Waterloo 132 kV line if a trip of the Blyth West – Munno Para 275 kV line was to occur	$141,851	10.7	We are monitoring this constraint to determine if options such as automatic runback control schemes for 132 kV wind farms in the Mid North are likely to alleviate this constraint
S>NIL_SGBN_SGSE-T2 Avoid an overload of Snuggery – Mayura – South East 132 kV line if a trip of the Snuggery – Blanche 132 kV line was to occur	$92,232	28.0	An automatic control scheme to alleviate this constraint is in service under system normal conditions
SVML_ROC_80 Keep the rate of change of flow from South Australia to Victoria across Murraylink HVDC interconnector below 80 MW per 5 min	$75,918	72.8	Constraint based on limit advice provided by Murraylink operator.
S_WATERLWF_RB Limit Waterloo Wind Farm output to its runback active power capability	$53,121	7.0	We are monitoring this constraint to determine if options such as inclusion of other 132 kV wind farms in the Mid North in existing or additional automatic runback control schemes are likely to alleviate this constraint

4.3 Emerging and future network constraints and performance limitations

The committed implementation of Project EnergyConnect, establishing a new interconnector between South Australia and New South Wales, is expected to change dispatch patterns of existing generators. Together with continuing significant renewable energy generation connections in South Australia, this is expected to lead to significant changes in congestion patterns on the transmission network. This will depend on where future generators connect or retire.

ElectraNet has conducted a 10-year forecast of generator expansion to achieve a 100% renewable energy target in South Australia by 2030, to identify potential development of generation in REZs.

The limitations that could bind due to the modelled generator connections are highlighted in the table below.

A high volume of renewable energy developments in the South East zone could see congestion develop between Tailem Bend and the Adelaide metropolitan area.

In addition, renewable energy development in the northern parts of South Australia (including the Mid North, Eyre Peninsula, Yorke Peninsula and possibly Roxby Downs zones) together with imported flows from Project EnergyConnect could see congestion develop between Robertstown and the Adelaide metropolitan area.

These areas are consistent with the zones identified for potential development in AEMO's 2020 ISP, although the required timing of projects to alleviate constraints may differ.

In addition, a high volume of renewable energy developments on Eyre Peninsula could see congestion develop between Cultana and Davenport.

Where possible, references are provided to other chapters or sections of this report that contain information regarding projects or initiatives that would resolve or mitigate the forecast limitations.

Forecast South Australian transmission network congestion

Limitation	Timing indication	Affected corridor	Forecast average binding hours (hrs/year) [22]		Potential mitigating project(s)
			2021-22 to 2030-31	2021-22 to 2040-41	
Loss of Templers West 275/132 kV transformer overloads Para 275/132 kV transformer	After 2023	Robertstown – Adelaide	853	1025	Install second Templers West 275/132 kV transformer
Loss of Robertstown 275/132 kV transformer overloads Waterloo – Waterloo East 132 kV	After 2023	Robertstown – Adelaide	300	845	Increase capacity of the Robertstown to Adelaide transmission corridor
Loss of Robertstown – Para 275 kV overloads Waterloo East – Waterloo 132 kV	After 2023	Robertstown – Adelaide	119	473	Increase capacity of the Robertstown to Adelaide transmission corridor
Loss of one 275 kV circuit between Davenport and Cultana overloads the other 275 kV circuit	After 2022	Davenport – Cultana	66	90	Remove plant rating limitations on the Davenport – Cultana 275 kV corridor
Loss of Mt Lock – Davenport 275 kV overloads Waterloo – Waterloo East 132 kV	After 2023	Robertstown – Adelaide	31	98	Increase capacity of the Robertstown to Adelaide transmission corridor
Loss of Tungkillo – Robertstown 275 kV overloads Para – Robertstown 275 kV	After 2026	Robertstown – Adelaide	24	100	Increase capacity of the Robertstown to Adelaide transmission corridor
Heywood – South East 275 kV	After 2026	Heywood – South East	34	66	Establish HorshamLink, or extend 500 kV system from Heywood to South East
Loss of Tailem Bend – Tungkillo – Cherry Gardens (275 kV) overloads Tailem Bend – Mobilong 132 kV	After 2023	Tailem Bend - Adelaide	19	138	Remove plant limits on Tailem Bend – Mobilong 132 kV String vacant Tailem Bend – Tungkillo 275 kV circuit (EC.11011)

[22] *Based on the 2020 ISP step change scenario.*

4.4 Potential projects to address future constraints

The connection of significant new loads, a change in the nature of the generation fleet, or changing gas prices can impact on the efficient development and operation of the transmission network. Such developments may lead to network constraints which 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 projects to address inter-regional and intra-regional constraints that may emerge in the future. Some of these projects will be required if new generation develops along the lines envisaged in the 2020 Integrated System Plan.

Other projects may be warranted if either the least-cost generator expansion changes or actual generator investment decisions do not follow the Integrated System Plan generator expansion forecasts. 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.

We have identified high-level potential projects through constraint and planning analysis (table next page). These projects would reduce network congestion in the future, warranting development if they deliver net benefits to customers. Some of these projects may also deliver minor improvements in network reliability. We plan to propose some of these projects as contingent projects in our 2023-24 to 2027-28 Revenue Proposal, while others will become contingent projects automatically if they appear as actionable projects in the ISP (Appendix E).

4.5 Frequency control schemes

There are currently three control schemes implemented in South Australia that are designed to contribute to system frequency control:

- a distributed automatic under-frequency load shedding (UFLS) scheme (section 4.5.1)
- a distributed automatic over-frequency generator shedding (OFGS) scheme (section 4.5.2)
- a System Integrity Protection Scheme (SIPS) (section 4.5.3).

4.5.1 Automatic under-frequency load shedding

South Australia's existing UFLS scheme is designed to return system frequency to normal following an event that leads to South Australia separating from the rest of the NEM.

The basic design premise of the UFLS scheme is that, in response to a separation event or a multiple contingency event[23], the frequency fall should be limited to 47 Hz by the controlled disconnection of load.

AEMO most recently reviewed the design of the UFLS scheme for South Australia as part of the 2020 Power System Frequency Risk Review[24] AEMO's assessment indicated that:

- there are periods during which insufficient load is forecast to be available for disconnection in the existing South Australian UFLS scheme. The amount of net load available for disconnection will continue to decrease as a result on the ongoing growth of distributed PV generation
- the existing UFLS scheme may not be adequate to arrest reductions in the power system frequency following the non-credible separation of South Australia from the NEM
- a protected event is recommended to manage the risk of cascading failures and prevent a system black if a non-credible separation of South Australia from the NEM was to occur during periods where UFLS is inadequate. AEMO is preparing a submission to the Reliability Panel on this basis.

Further, AEMO recommended that all transmission and distribution network service providers review the design of existing UFLS schemes with the aim of:

- ensuring that the amount and distribution of available load in the UFLS scheme is adequate to ensure its effectiveness, and make changes to optimise the performance of the scheme
- implement improvements such as dynamic arming schemes that are designed to disarm UFLS relays when circuits are in reverse flow, so that back-feeding distribution feeders will not exacerbate any under frequency conditions by tripping due to UFLS.

ElectraNet has worked with AEMO to develop a power system constraint that limits import into South Australia on the Heywood interconnector to an appropriate level such that risk of cascading failures is reduced if non-credible separation of South Australia from the NEM was to occur.

ElectraNet is working with:

- transmission network direct-connect customers to ensure UFLS arrangements for each customer comply with Rules obligations
- SA Power Networks to quantify and provide to AEMO the available load in South Australia on UFLS at any moment in time using SCADA data
- AEMO to assess the impact of the loss of a large generator and subsequent distributed PV disconnection.

Potential projects to address inter-regional and intra-regional constraints that may emerge

Project name and potential driver	Project description and expected benefit	Lead time	Cost ($M)
Mid North to Adelaide transfer capacity increase Increased generation or large-scale storage in the Mid North, Upper North and Eyre Peninsula	Potential options include: • Install a 2nd Templers West 275/132 kV transformer, decommission the Templers to Waterloo 132 kV line and relocate the modular power flow equipment installed on that line • Construct new double circuit 275 kV high-capacity lines between Robertstown and Templers West, and rebuild the 275 kV "East" circuit as high-capacity double circuit lines between Templers West and Para • Construct new double circuit 275 kV high-capacity lines between Davenport and Robertstown or Para, possibly replacing one of the existing 275 kV circuits between Davenport and Para This project would increase transfer capacity between the Mid North (Robertstown and Davenport) and Adelaide to allow for delivery of increased dispatch of renewable generation and energy storage in the Mid North and North of South Australia, and enable increased export from South Australia to New South Wales.	2-3 years RIT-T[25] 3-4 years easement acquisition, detailed design and delivery	**200-650** **(depending on option)**
Main Grid system strength support Increasing penetration of distributed energy resources in the metropolitan area may require system strength or dynamic voltage control to be increased, to ensure continued stable system response to disturbances	Install one or two synchronous condensers or other source of fast voltage control (e.g. STATCOM) to increase system strength and/or dynamic voltage capability on the transmission network. Enable continued growth in distributed energy resources.	1-2 years RIT-T[25] 2-3 years detailed design and delivery Robertstown – Adelaide	**80-120**
Upper South East network augmentation Increased generation including rooftop solar PV and large-scale wind and solar farms in the Eastern Hills and South East	String the vacant 275 kV circuit between Tailem Bend and Tungkillo and install dynamic reactive support or a synchronous condenser if required at Tailem Bend. Increase transfer capacity between Tailem Bend and Adelaide to allow for greater imports and exports of renewable energy and increase system strength if required. Potential to couple with Main Grid system strength support project.	1-2 years RIT-T[25] 1-2 years detailed design and delivery	**30-50**
Eyre Peninsula Upgrade Increased generation or large-scale loads or storage southwest of Port Augusta	Establish the third and fourth 275 kV circuits between Davenport and Cultana and/or upgrade the Cultana to Yadnarie lines from 132 kV to 275 kV operation. Increase the ability to supply future large loads on the Eyre Peninsula, such as mining loads or large hydrogen hub development.	1-2 years RIT-T[25] 3-4 years easement acquisition, detailed design and delivery	**50-150**
Project EnergyConnect Upgrade Market driven requirement for increased combined interconnector transfer capability in either direction	Incorporate additional loads and storage facilities the SPS to enable all interconnectors to be operated closer to their thermal limits, and/or improve the ability to independently control power flows across Project EnergyConnect and the Heywood interconnector. Increase the combined transfer capability of the Heywood interconnector and Project EnergyConnect.	1-2 years RIT-T[25] 2-3 years detailed design and delivery	**100-150**

[23] *As defined in the Frequency Operating Standards.*
[24] *AEMO's 2020 Power System Frequency Risk Review, available from www.aemo.com.au.*
[25] *May be shorter duration if a future ISP identifies this to be an actionable project.*

4.5.2 Automatic over-frequency generator shedding

The purpose of OFGS is to manage the frequency performance during islanding events resulting from non-credible or multiple contingencies during high export to Victoria. The South Australia OFGS operates in the frequency range of 51 to 52 Hz.

AEMO, with ElectraNet, designed the South Australia OFGS to limit frequency rise in South Australia to 52 Hz in line with the frequency operating standards. The objective of the scheme is to coordinate the tripping of generation in a pre-determined manner, tripping low inertia generators first, to maximise the inertia online. This seeks to minimise exacerbation of the rate of change of frequency (RoCoF) that would result from disconnecting synchronous generators that provide system inertia during extreme frequency events. Actual operation of the scheme is expected to be rare.

The scheme is designed to only operate for frequency excursions above the upper limit of the “operational frequency tolerance band” of 51 Hz. Generation to be tripped is split into eight blocks, each with around 150 MW of wind generation, set to trip between 51 Hz and 52 Hz.

System inertia is the predominant factor for effective operation of the OFGS and has typically been provided by synchronous generation. As the proportion of non-synchronous generation has increased, the system inertia has declined. This has led to the potential for increased RoCoF for large contingency events, which could cause loss of discrimination between OFGS groups, increasing the risk of over-tripping, causing frequency decline and subsequent UFLS occurring.

When interconnected to Victoria, this OFGS limitation is currently mitigated through a constraint equation that limits RoCoF within South Australia to 3 Hz/s for a non-credible loss of the Heywood Interconnector. Any change to this constraint equation would necessitate a review of the OFGS scheme.

AEMO most recently reviewed the OFGS scheme for South Australia as part of the 2020 Power System Frequency Risk Review.[26] In the 2020 PSFRR, AEMO recommended that AEMO and ElectraNet review and expand the South Australian OFGS scheme and modify it if required, to include additional generation in the scheme.

4.5.3 System Integrity Protection Scheme

The non-credible loss of multiple generating units in South Australia, at times of high import into South Australia, can lead to extreme flows on the Heywood Interconnector, causing it to trip due to instability. This loss of multiple generators and islanding of South Australia would result in rapid frequency decline and poses a high risk of a state-wide blackout.

The SIPS was designed to rapidly identify conditions that could otherwise result in a loss of synchronism between South Australia and Victoria. The SIPS is designed to assist with the management of these conditions by rapidly injecting power from batteries or shedding some targeted loads, to assist in re-balancing supply and demand in South Australia, preventing a loss of the Heywood interconnector and subsequent islanding of South Australia from the NEM.

The SIPS operates in three discrete, progressive stages. These stages operate in an escalating manner, in that the operation of each stage is intended to minimise the need to progress to the next stage. The three stages are shown on the next page.

AEMO reviewed the design of the South Australian SIPS scheme in the 2018 PSFRR and confirmed the findings in the 2020 PSFRR.[27] AEMO’s assessment concluded that:

- Under all scenarios, activation of Stage 1 has not shown any detrimental effect on South Australian power system stability. The studies carried out confirm the ability of Stage 1 in avoiding activation of Stage 2 for some dispatch scenarios
- The outcome of Stage 2 depends on the amount of load being shed. Customer load being a variable, it is likely (and studies have confirmed) that under some circumstances activation of Stage 2 disconnects more load than required, resulting in additional generation tripping on over voltages. For some scenarios a reduction in the amount of load shed does not avoid activation of Stage 3
- There were instances where the Tailem Bend loss of synchronism relay failed to detect unstable power swings, thereby being unsuccessful in activating Stage 2
- The Tailem Bend loss of synchronism relay failed to detect unstable power swing during high demand and high import conditions.

[26] As is the case with underfrequency load shedding, the amount of net load available for disconnection will decrease as a result on the ongoing growth of distributed PV generation.

[27] AEMO’s 2020 Power System Frequency Risk Review, available from www.aemo.com.au.

[28] See section 5.2.3 of AEMO’s 2018 Power System Frequency Risk Review, available from www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Power-System-Frequency-Risk-Review.

[29] On 20 June 2019 the Reliability Panel published a final determination declaring a protected event in accordance with AEMO’s request, including:
- upgrading the existing system integrity protection scheme (SIPS) in South Australia
- limiting imports across the Heywood interconnector during periods of forecast destructive wind conditions.

The Reliability Panel’s determination is available at https://www.aemc.gov.au/market-reviews-advice/request-declaration-protected-event-november-2018.

STAGE 1

Fast response from battery energy storage systems

Activation of this stage by an independent trigger enables battery energy storage systems to provide additional active power to the system. The activation signal will be initiated if imported power across the Heywood Interconnector either:

- increases at a rate of change which is faster than a rate which could occur through any reasonably foreseeable load increase, or
- increases beyond a defined threshold.

STAGE 2

Load shedding trigger to shed up to 200 MW of South Australian load[28]

An unstable power swing trigger is initiated from a pair of redundant loss of synchronism detection relays located at the Tailem Bend substation. The trigger will issue a load shedding signal to selected transmission substations.

Additionally, a load shedding trigger is initiated if imported power across the Heywood interconnector increases beyond a defined threshold. Relays issue a load shedding signal to the same transmission substations as for the unstable power swing trigger.

STAGE 3

Out-of-step trip scheme (islanding South Australia)

If required, the third component of SIPS is initiated by duplicated loss-of-synchronism relays at South East substation. The out-of-step signal trips 275 kV circuit breakers at South East substation to open the Heywood interconnector, islanding the South Australian power system.

AEMO recommended an investigation of technologies and solutions to upgrade the existing SIPS, considering:

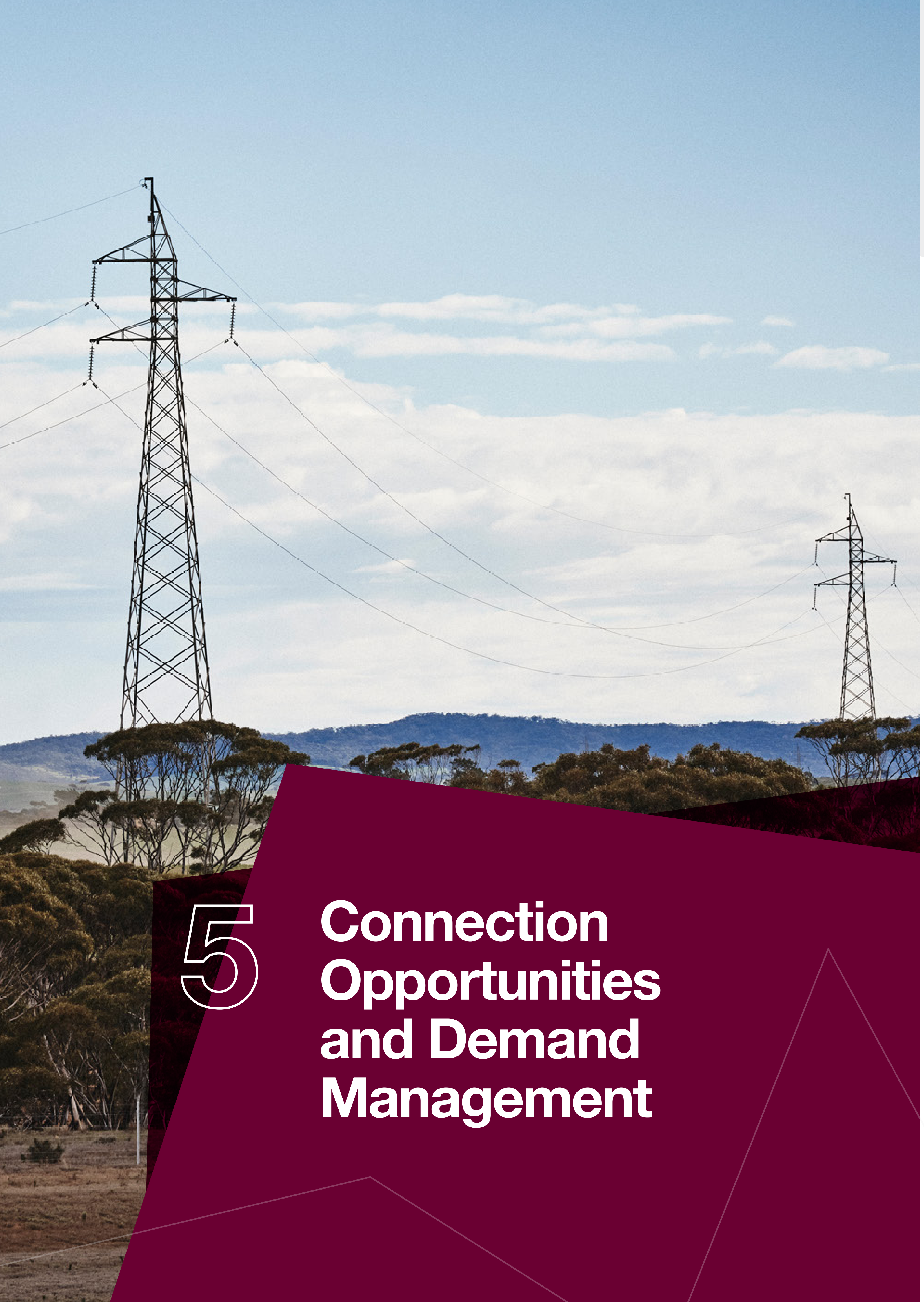
- Alternative mechanisms to detect onset of loss of synchronism between South Australia and the rest of the NEM, because the impedance-based Tailem Bend and South East loss of synchronism relays failed to detect unstable power swings in some simulations
- Dynamic arming of load blocks, batteries, and potentially the Murraylink interconnector, based on real-time measurement and pre-processing of information for different generation loss events (“Stage 2”). This is required because the current fixed load shed blocks may cause under or over-tripping and over-voltages, leading to trip of additional generation under some conditions. Detailed investigation of technologies and design is required due to the countless number of generation tripping events that could conceivably occur in the South Australia power system
- This SIPS upgrade should be progressed as a Protected Event emergency frequency control scheme to mitigate the risk of system black following a loss of multiple generators in South Australia.[29]

In consultation with AEMO, we have explored the feasibility of using a synchronised phasor-based scheme to address the shortcomings of Stage 1 and 2 of the SIPS. The new Wide Area Protection Scheme (WAPS) scheme would provide the following improvements compared to Stage 1 and Stage 2 of the SIPS:

- More accurate detection and rapid triggering of battery energy storage system and load response elements, minimising the risk of a trip of Heywood interconnector
- Real time measurement of the available response
- Initiation of a proportionate load shedding response when triggered.

Following the successful completion of the feasibility study, we have now commenced the detailed design of the WAPS.

We expect the WAPS to be in service by October 2022.



5 Connection Opportunities and Demand Management

This chapter provides an update regarding new connections and withdrawals and identifies proposed new connection points for which network support solutions are being sought or considered.

Details about the connection services we offer are available on our website.

FIND OUT MORE

We encourage any potential new generators or customers to contact our Corporate Development Team.

connection@electranet.com.au

5.1 New connections and withdrawals

Several new generators have connected or committed to connect, and other generators have either withdrawn or announced their intention to withdraw, since the publication of the 2020 Transmission Annual Planning Report (table below).[29]

Generators that have connected, committed to connect or withdrawn since 30 October 2020

Generator	Type	Size	Location	Status
Adelaide Desalination Plant	Storage – battery Solar PV	6.27 MW 13 MWh 11 MW	Southern Suburbs	Committed
Bolivar Waste Water Treatment	Storage – battery Solar PV	2.46 MW 5 MWh 11.25 MW	Northern Suburbs	Anticipated in 2021
Mannum – Adelaide Pumping Station No. 2	Solar PV	16.8 MW	Mannum – Adelaide No. 2 Pumping Station	Connection in 2021
Morgan to Whyalla Pipeline No. 1 PS and Filtration Plant	Solar PV	6.12 MW	Morgan – Whyalla No. 1 Pump Station	Connection in 2021
Morgan to Whyalla Pipeline No. 2 PS	Solar PV	5.88 MW	Morgan – Whyalla No. 2 Pump Station	Connection in 2021
Morgan to Whyalla Pipeline No. 3 PS	Solar PV	7.38 MW	Morgan – Whyalla No. 3 Pump Station	Connection in 2021
Morgan to Whyalla Pipeline No. 4 PS	Solar PV	5.88 MW	Morgan – Whyalla No. 4 Pump Station	Connection in 2021
Lincoln Gap Wind Farm Stage 2	Wind turbine	86.4 MW	Corraberra Hill	Committed
SA Government Virtual Power Plant – Stage 2	Storage – Virtual power plant	5 MW	Distributed	Committed
Simply Energy VPP	Storage – Virtual power plant	6 MW	Distributed	Committed
Snapper Point Power Station	Open Cycle Gas Turbine	154 MW	Pelican Point	Committed
Port Augusta Renewable Energy Park	Solar PV Wind turbine	79.2 MW 210 MW	Davenport	Under construction Change of generating technology being assessed
Torrens Island A1	Turbine - Steam sub critical	120 MW	Torrens Island	Withdrawn 30 September 2021
Torrens Island A3	Turbine - Steam sub critical	120 MW	Torrens Island	Mothballed Planned withdrawal 30 September 2022
Torrens Island B1	Turbine – Steam sub critical	200 MW	Torrens Island	Mothballed
New Osborne	Combined cycle gas turbine	118 MW 62 MW	Osborne	Planned withdrawal 31 December 2023

[29] *Sourced from AEMO's NEM Generation Information October 2021, available at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.*

5.2 Connection opportunities for generators

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

However, this assessment is limited to a few operating conditions and does not attempt to define the amount and value of constraints that could be experienced in terms of energy lost by connecting generation at any particular location. We have not considered the potential impact of constraints outside of South Australia on the ability to export power out of South Australia. We recommend that parties seeking connection to the network carry out a detailed network access and market impact assessment.

In making this assessment, we have included the impact of generators that are considered committed to connect.

5.2.1 Approach to generation connection opportunity calculations

We have assessed the anticipated thermal ability of the transmission network to accommodate additional generation after the full transfer capacity of Project EnergyConnect is anticipated to have been released, for four different system conditions (table below). These were selected to represent a range of dispatch conditions that may result in higher than usual intra-regional constraints on generator dispatch, at times when South Australian generation is not constrained by limits on export from South Australia to the rest of the NEM.

Initial system conditions considered in the assessment of the ability of the South Australian transmission system to accommodate additional generation

System condition	SA demand (MW)	SA system losses (MW)	Heywood interconnector flow (MW)	Project Energy-Connect flow (MW)	Conventional generator output (% of capacity)	Wind farm output (% of capacity)	Solar farm output (% of capacity)
High summer demand sunny at noon	2,500	170	490 (import)	740 (import)	5%	50%	95%
High winter demand very windy and overcast	2,000	140	100 (export)	190 (import)	5%	90%	0
Medium demand sunny and still	1,400	100	600 (import)	470 (import)	2%	5%	90%
Very low daytime demand sunny and still	0	30	230 (export)	260 (export)	2%	5%	95%

At each location, we gradually increased the output of a new generator while adjusting interconnector flows within their limits to maintain the supply-demand balance. The output of the new generator was increased until a voltage limitation or a thermal overload was observed, with single credible contingencies considered. The impact of existing run back schemes was also considered (where practicable).

We have not considered potential impacts on new or existing generators that could arise from any system strength limitations.

The indicative ability of the existing South Australian transmission network and connection points to accommodate new generation (in addition to any existing and committed generation) is summarised in section 5.4.

In some cases, it may be feasible to connect larger generators if low-cost upgrades can increase the network's transfer capacity; for example, by replacing low-cost plant that may limit the available rating of a transmission line.

We have incorporated the impact of committed projects (section 6.2).

5.2.2 General observations about connection opportunities for generators

Almost any point in the proximity of the Main Grid 275 kV transmission system should be suitable for a new generator to connect. Several 275 kV substations in the Mid North represent strategic locations close to fuel resources, including wind.

Sites that are electrically favourable for connecting generation are located along the 275 kV backbone from Cultana (near Whyalla) to South East (near Mount Gambier). However, generation connected anywhere from Tungkillo through to Tailem Bend and South East may be subject to co-optimised dispatch with the Heywood interconnector, due to its potential impact on the ability to import power from Victoria and the rest of the NEM.

Due to physical space constraints, Davenport (near Port Augusta), Cultana (near Whyalla) and Robertstown are each approaching the limit of their ability to physically accommodate new connections. Further connections at either location are likely to require substantial investment by the connecting party to either expand the site or establish a nearby new substation. Bundey is expected to be a suitable site for proponents near Robertstown to connect, once it has been established as part of Project EnergyConnect.

At times of coincident high wind generation output and high solar generation output, including from rooftop solar PV, generation constraints can be significantly more onerous than presented in section 5.5. Conversely, such conditions could be favourable for energy storage proposals. Again, we recommend that parties seeking connection to the network carry out a detailed network access and market impact assessment.

While the existing Metropolitan 275/66 kV system may have capacity to accept new generation connections, population density limits the ability to economically extend the network. Also, existing maximum fault levels are approaching the plant capability limits of both ElectraNet's and SA Power Networks' assets, particularly in the vicinity of Torrens Island, LeFevre, New Osborne, Kilburn, Northfield, Magill and within the Adelaide Central Business District (CBD). Connection of new synchronous generation could initiate a need for major replacement of transmission or distribution assets to address fault level issues.[30]

5.2.3 Implications of South Australian system strength requirements

AEMO currently maintains adequate levels of system strength in South Australia by directing synchronous generation when necessary and applying a non-synchronous generation system constraint that considers the synchronous generators online at the time within South Australia.

ElectraNet has installed four high-inertia synchronous condensers to meet minimum system strength requirements specified by AEMO in 2018 for South Australia (section 6.1). The four synchronous condensers will also meet the minimum threshold of inertia of 4,400 MWs that AEMO determined for South Australia in 2018, with no other synchronous plant on-line in South Australia.

The four synchronous condensers in combination with the requirement for at least two large synchronous generating units to be online allow 2,500 MW of non-synchronous generation to be dispatched within South Australia for most operating conditions.[31]

The total installed capacity of non-synchronous generation in South Australia now exceeds 2,500 MW, so the non-synchronous generation system constraint remains in place at this new increased level now that the four synchronous condensers have been installed. However, it is anticipated that other constraints, such as constraints due to thermal capacity, stability or voltage limitations and interconnector transfer capacity are likely to bind at times to limit non-synchronous generation at levels below the non-synchronous generation system strength constraint.

The successful completion of a system strength Full Impact Assessment conducted for a proposed non-synchronous generator in accordance with clause 5.3.4B of the Rules is a pre-requisite for connection and inclusion in the non-synchronous generation system constraint.

ElectraNet and AEMO continue to utilise an agreed approach for how a generator can be excluded from the non-synchronous generation system constraint. The following conditions must be met:

1. The generator performance standard compliance must be verified with validated R2 models; and
2. The generator must propose mitigation measures which may include control system modifications or installation of additional plant that increases the non-synchronous generation system constraint limit by their rated capacity. An increase in the constraint by part of a non-synchronous generator's rated capacity would be considered but the removal of the generator from the constraint would then be on a pro-rata basis. This assessment will be performed as a Full Impact Assessment.

[30] *Expected maximum and minimum fault levels for each connection point are available from our Transmission Annual Planning Report web page, available at electranet.com.au/what-we-do/network/regulated-network-reports-and-studies.*

[31] *AEMO, Transfer Limit Advice – System Strength VIC and SA v38, page 13, published July 2021. Available at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice*

5.2.4 Opportunities to connect to Project EnergyConnect

We are aware that there is significant interest among potential renewable energy and storage proponents keen to take advantage of the increased interconnection that will be introduced by Project EnergyConnect.

While Project EnergyConnect has secured final regulatory approval and financial commitments from both ElectraNet and TransGrid, environmental approvals, easement agreements and construction contracts, as well as the final design of the 900 km transmission line remain to be completed.

Physical on-the-ground construction start dates are also still being finalised. However, works are not anticipated to commence in either South Australia or New South Wales until the end of 2021 or early 2022.

For proponents interested in connecting to Project EnergyConnect, the connection process will be similar to current processes for connection to the transmission network. However, there are several key milestones for Project EnergyConnect that need to be met before a formal connection journey can begin and an application can be submitted.

New connection enquiries can be formally lodged and progressed as soon as Project EnergyConnect reaches Considered Project[32] status, which will mean that the following conditions have been met:

- necessary land and easements acquired
- all necessary planning and development approvals obtained
- the project has passed the RIT-T (already achieved), and
- construction has either commenced or a firm date is set for it to commence.

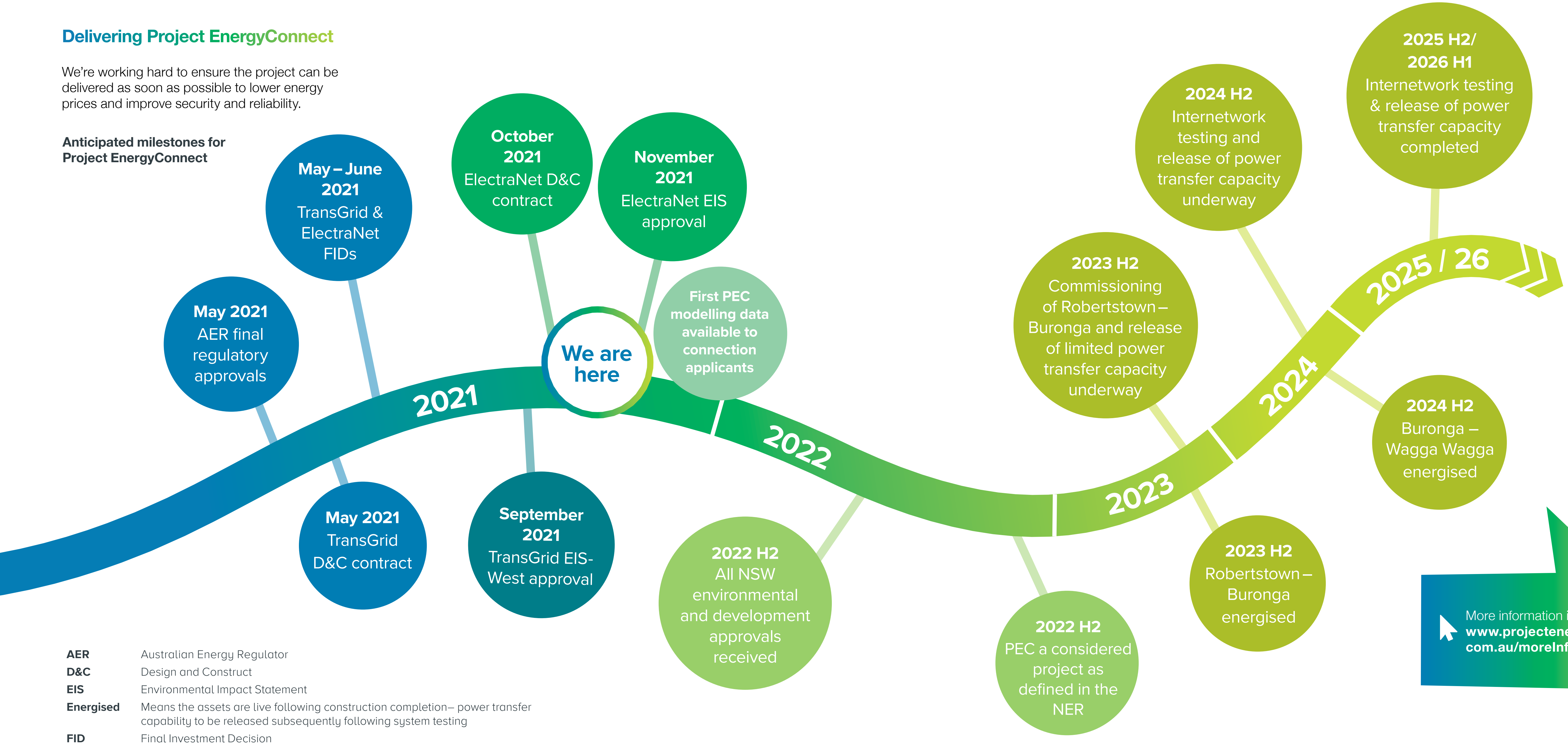
Reaching that point will mean that the project design is sufficiently complete to model the network augmentation in sufficient detail to allow load flow and dynamic simulations to be undertaken in relation to a proponent's project. Proponents need this modelling and information to prepare a formal Connection Application.

Based on current timings, ElectraNet and TransGrid anticipate that modelling will have reached sufficient maturity to be available to Connection Applicants by the end of 2021 or early 2022, and that PEC will reach Considered Project status in the second half of 2022 (below. Updates on this progress will be shared regularly by ElectraNet and TransGrid.

Delivering Project EnergyConnect

We're working hard to ensure the project can be delivered as soon as possible to lower energy prices and improve security and reliability.

Anticipated milestones for Project EnergyConnect



More information is available at **www.projectenergyconnect.com.au/moreInformation.php**

AER	Australian Energy Regulator
D&C	Design and Construct
EIS	Environmental Impact Statement
Energised	Means the assets are live following construction completion– power transfer capability to be released subsequently following system testing
FID	Final Investment Decision
NER	National Electricity Rules

[32] *"Considered Project" is a defined term under the Rules which greenlights an infrastructure project as an approved addition to the NEM.*

5.2.5 Generator connection impacts on power quality

Supporting the ongoing connection and integration of new generation technologies within the power system, ElectraNet performs complex power quality studies and assessments to ensure that customers will continue to experience satisfactory power quality.

To support these studies, ElectraNet requires generators to submit a site-specific power quality model for use in the PowerFactory simulation tool that is consistent with Section 4.6 of the *AEMO Power System Model Guidelines*[33], and a power quality design report that incorporates sufficient supporting studies and assessment results as part of the 5.3.4A(b2) submission under the Rules.

5.3 Connection opportunities for load customers

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

There is an under-voltage load shedding scheme applied to major loads that are connected at or near Davenport (at the northern end of the transmission system) to allow for secure operation under outage conditions. Further load connections in this area would be incorporated into this scheme to ensure that voltage levels continue to be adequately managed.

Until 10 years ago, metropolitan electricity demand grew steadily because of residential infill, commercial and industrial development in the Adelaide metropolitan area. However, recently the loads have generally remained flat. SA Power Networks' distribution network supplies individual electricity customers, and the existing Metropolitan 275/66 kV network can accommodate new load connections. Depending on size and location, new load connections may create a need to substantially augment or replace existing assets.

In other regions, we have assessed the ability of existing connection points to accommodate the connection of new large loads (section 5.4). The values listed represent the additional load that, without transmission network upgrades, could be connected to the connection point's high voltage bus in addition to the forecast South Australian 2024-25 10% POE load at the time of early evening maximum demand, with:

- Conventional generators dispatched to 56% of capacity
- Wind farms dispatched to 12% of capacity
- Solar farms off
- 90 MW of SA system losses
- Import of 300 MW across the Heywood interconnector and 300 MW across Project EnergyConnect.

5.4 Summary of connection opportunities

An indicative summary of the ability of the South Australian transmission network to accept generator or load connections in 2024-25 is given in the table starting on the next page. The summary includes the impact of Project EnergyConnect and the synchronous condensers at Davenport and Robertstown, as well as other upgrade works that are planned to be completed by that time. It includes the impact of committed changes to the generation fleet.[34]

We emphasise that these values only provide a high-level non-binding 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. For some system conditions that are not included in the table, such as at times of very high wind generation output with moderate to low demand, the total dispatch of South Australian generation could be constrained by the capacity of the interconnectors to export electricity from South Australia.

We have not considered the potential impact of constraints in Victoria and New South Wales, or elsewhere in the NEM. We have not considered any impact of co-optimised dispatch for generators connected on interconnector flow paths.

We encourage any potential new generators or customers to contact our Corporate Development Team:

connection@electranet.com.au

The available capacity to connect new load and generation represents the capability of the existing transmission network only and does not account for any additional transformer or network capacity that may be required to facilitate connection at lower voltage levels. Any connection that proceeds will impact the ability of the system to accommodate connections at other sites.

For each system condition we have indicated the amount of additional generation dispatch or new load that could be accommodated at each connection point without exceeding voltage or capacity limits, should the most onerous single credible contingency occur. We have not considered constraints that AEMO would apply to restore system security after a contingency has occurred.

[33] *AEMO's Power System Model Guidelines are available at* https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/modelling-requirements.

[34] *Considered changes to the generation fleet include announced withdrawals and proposed new connections that are committed or committed* according to AEMO's commitment criteria. See AEMO's generation information page at* https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Indication of available capacity to connect generation and load in 2024-25

Connection point	Additional generation that could be connected (MW)				Additional load that could be connected (MW)
	Very low daytime demand Sunny and still	Medium demand Sunny and still	High winter demand Very windy, overcast	High summer demand Sunny at noon	Very high summer demand Low wind, early evening
Main Grid (275 kV)					
Davenport	600+	600+	300	125	300+
Corraberra Hill	450	425	250	125	300+
Cultana	500	525	250	125	300+
Mt Gunson South	225	225	225	125	50
Bungama	550	575	175	50	300+
Blyth West	425	350	175	25	300+
Munno Para	275	225	175	20	125
Brinkworth	525	500	200	325	275
Templers West	350	375	125	225	300+
Mount Lock	500	575	250	225	300+
Canowie	500	600	250	300	300+
Belalie	575	575	275	300	300+
Mokota	575	575	275	400	300+
Willalo	575	575	275	325	300+
Robertstown	600+	600+	600+	200	300+
Bundey	600+	600+	600+	200	300+
Tungkillo	600+	600+	600+	600+	300+
Para	600+	600+	600+	600+	300+
Parafield Gardens West	600+	600+	600+	600+	300+
Pelican Point	600+	600+	600+	600+	300+
Le Fevre	600+	600+	600+	600+	300+
Torrens Island	600+	600+	600+	600+	300+
Kilburn	500	525	550	550	125
Northfield	475	600+	600+	600+	175
Magill	600+	600+	600+	600+	300+
City West	500	600+	600+	550	200
Happy Valley	600+	600+	600+	600+	300+
Morphett Vale East	425	550	600	600	200
Cherry Gardens	600+	600+	600+	600+	300+
Mount Barker South	600+	600+	600+	600+	300+
Tailem Bend	600+	325	600+	200	300+
South East	575	600+	600+	575	300+
Upper North (132 kV)					
Mount Gunson	60	60	60	60	10
Mount Gunson South	225	225	225	125	40
Pimba	60	60	60	60	10
Neuroodla	5	5	5	5	0
Leigh Creek South	5	5	5	5	0

Connection point	Additional generation that could be connected (MW)				Additional load that could be connected (MW)
	Very low daytime demand Sunny and still	Medium demand Sunny and still	High winter demand Very windy, overcast	High summer demand Sunny at noon	Very high summer demand Low wind, early evening
Eyre Peninsula (132 kV)					
Cultana	250	275	175	125	100
Whyalla Central	150	175	175	125	20
Yadnarie	250	275	175	150	100
Port Lincoln Terminal	250	275	175	150	100
Wudinna	80	80	80	80	20
Mid North and Riverland (132 kV)					
Bungama	175	200	80	80	100
Port Pirie	100	100	80	80	20
Baroota	0	20	20	0	0
Brinkworth	275	275	60	200	125
Clare North	150	150	40	150	80
Morgan–Whyalla Pump Station No 4	175	175	20	100	20
Morgan–Whyalla Pump Station No 3	100	300	225	225	5
Morgan-Whyalla Pump Station No 2	100	300	225	250	5
Morgan–Whyalla Pump Station No 1	100	150	175	25	5
North West Bend	100	475	200	150	5
Monash	100	450	200	300	5
Berri	80	100	100	100	5
Waterloo	225	250	20	100	40
Hummocks	60	60	40	20	0
Ardrossan West	60	60	40	10	0
Dalrymple	60	40	20	10	0
Kadina East	60	60	40	10	10
Templers	200	200	60	125	125
Dorrien	100	125	80	125	100
Templers West	100	125	100	125	60
Roseworthy	125	125	100	125	100

Connection point	Additional generation that could be connected (MW)				Additional load that could be connected (MW)
	Very low daytime demand Sunny and still	Medium demand Sunny and still	High winter demand Very windy, overcast	High summer demand Sunny at noon	Very high summer demand Low wind, early evening
Eastern Hills (132 kV)					
Para	200	175	175	175	20
Angas Creek	125	125	125	125	40
Millbrook	0	0	5	0	0
Mannum–Adelaide Pump Station No 3	125	125	125	125	80
Mannum–Adelaide Pump Station No 2	125	125	125	125	80
Mannum–Adelaide Pump Station No 1	10	20	20	0	0
Mannum	125	150	150	150	60
Mobilong	200	250	325	250	125
Murray Bridge-Hahndorf No 1	80	80	80	80	20
Murray Bridge-Hahndorf No 2	175	175	175	175	125
Kanmantoo	60	60	40	40	20
Murray Bridge-Hahndorf No 3	175	175	175	175	125
Back Callington	60	60	60	60	0
Mount Barker	200	225	225	225	60
Cherry Gardens	125	125	125	125	60
South East (132 kV)					
Tailem Bend	100	100	150	150	10
Keith	150	150	80	175	100
Kincraig	150	150	80	125	40
Penola West	115	150	60	100	80
Mt Gambier	80	100	20	100	40
Blanche	60	80	10	80	40
Snuggery	60	60	0	60	40
South East	100	175	60	100	150

5.5 Proposed and committed new connection points

In previous Transmission Annual Planning reports, a new load connection point had been proposed by SA Power Networks at Gawler East in the Mid North to meet localised growing demand. A Gawler East connection point is not currently proposed, as the expected development timeframes are unclear. However, it is possible that the need to develop a Gawler East connection could arise again at some point in the future, subject to actual developments in the local area.

We will establish a new 275/330 kV substation at Bundey (near Robertstown) as part of Project EnergyConnect.

5.6 Projects for which network support solutions are being sought or considered

There is one planned consultation for forecast limitations for which we plan to seek proposals for network support solutions (table below).

Future dates are indicative only. Reports will be published on ElectraNet's website, with a summary on AEMO's website.[35, 36] We also liaise with AEMO to notify interested parties when we publish new RIT-T reports through the "AEMO Communications" email notifications.[37]

We are also currently engaging with the market for the provision of FFR services.

Planned consultation for which ElectraNet plans to seek proposals for network support solutions

RIT-T	Expected project commitment date	Consultation status
Transmission Network Voltage Control Refer to section 7.4 of this report.	2023	We plan to commence application of the RIT-T with publication of a PSCR in 2022. Proponents of potential network support solutions will be encouraged to make a submission in response to the PSCR.

[35] ElectraNet's RIT-T page is available at www.electranet.com.au/what-we-do/network/regulatory-investment-test/.

[36] AEMO's website is available at www.aemo.com.au.

[37] To sign up to the AEMO Communications newsletter, use this link: https://aemo.us10.list-manage.com/ track/ click?u=eae433173c2b1acb87c5b07d1&id=3a670fe4f3&e=f482090852.

Para Substation

6 Completed, Committed, and Pending Projects

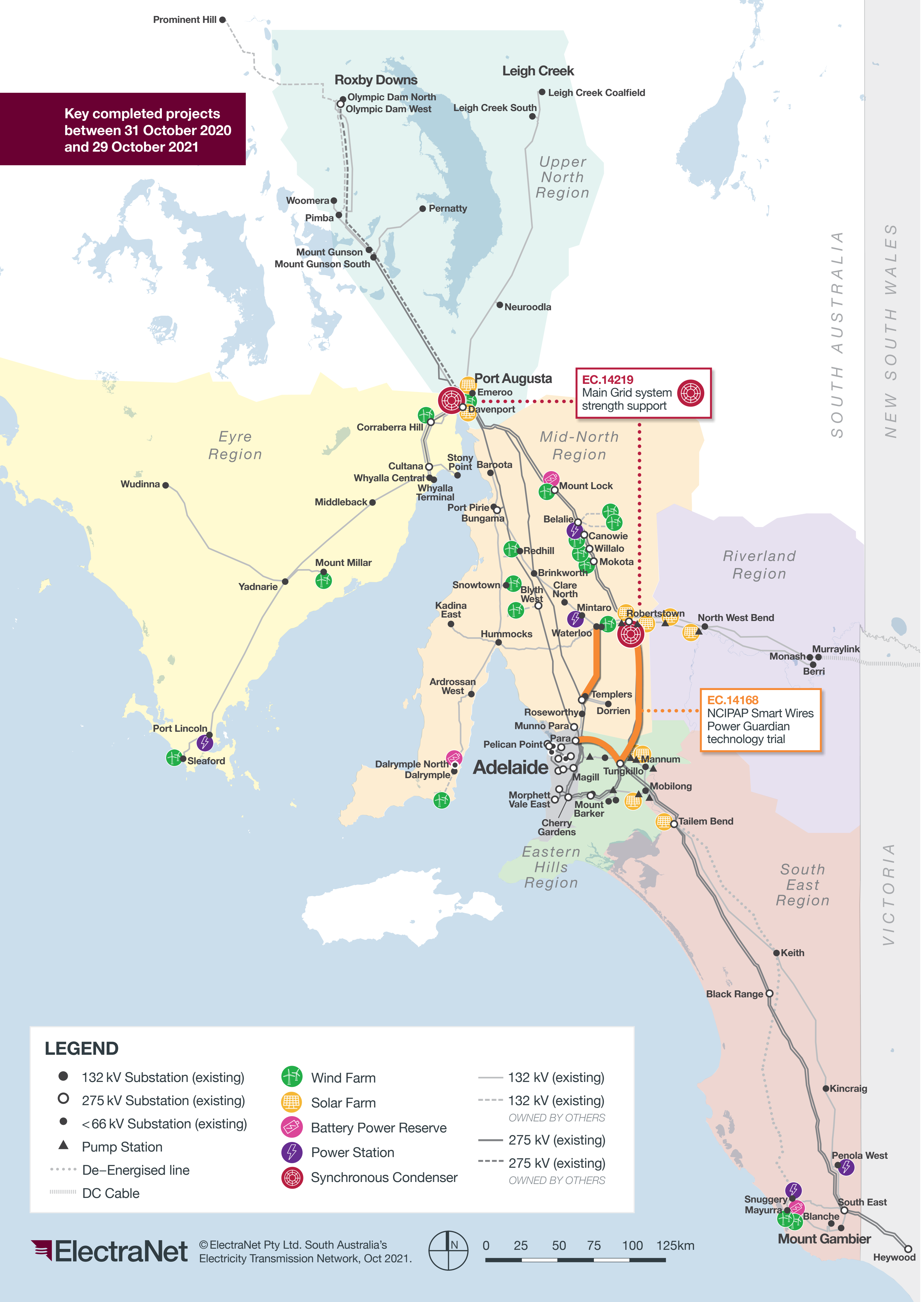
This chapter provides a high-level summary of significant projects that we have completed, committed to or have become pending over the last year.

6.1 Recently completed projects

We have completed several significant projects to remove network limitations and address asset condition during the past 12 months (table below and map overleaf).

Network projects completed between 31 October 2020 and 29 October 2021 (inclusive)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14207 System Integrity Protection Scheme (SIPS) Implement a system integrity protection scheme to mitigate risk to the South Australian electricity system prior to South Australian islanding contingencies, utilising rapid transmission-level load tripping and injection from batteries where available (completed in two stages in December 2017 and December 2018). Investigate the feasibility of upgrading the SIPS to a Wide Area Protection Scheme (WAPS) with the use of Power Monitoring Units (PMUs) for more precise event detection, and investigate dynamic and proportionate arming of participating loads and battery energy storage systems.	All	Stability Operational	SIPS in-service December 2017 (load tripping) and December 2018 (battery injection) WAPS feasibility study completed December 2020
EC.14219 Main Grid system strength support Install four synchronous condenser units, two at Davenport and two at Robertstown to provide system strength services and to address the gaps for system strength and inertia in South Australia as declared by AEMO.	Main Grid	Stability Augmentation	July 2021 (Davenport) September 2021 (Robertstown)
EC.14168 NCIPAP Smart Wires Power Guardian Technology Trial Install Smart Wires Power Guardian units on the Templers to Waterloo 132 kV line and uprate the Robertstown to Para 275 kV and the Templers to Roseworthy 132 kV lines to increase the transfer capacity of the transmission network in the Mid North region of South Australia.	Mid North	Market benefit (NCIPAP) Augmentation	May 2021 (Smart Wires Power Guardian) October 2021 (Line uprates)



6.2 Committed projects

Committed projects are those projects for which the RIT-T has been completed (where required) and the ElectraNet Board has given approval. We are currently undertaking several committed projects which are expected to be completed between now and 2028 (table below and figure overleaf).

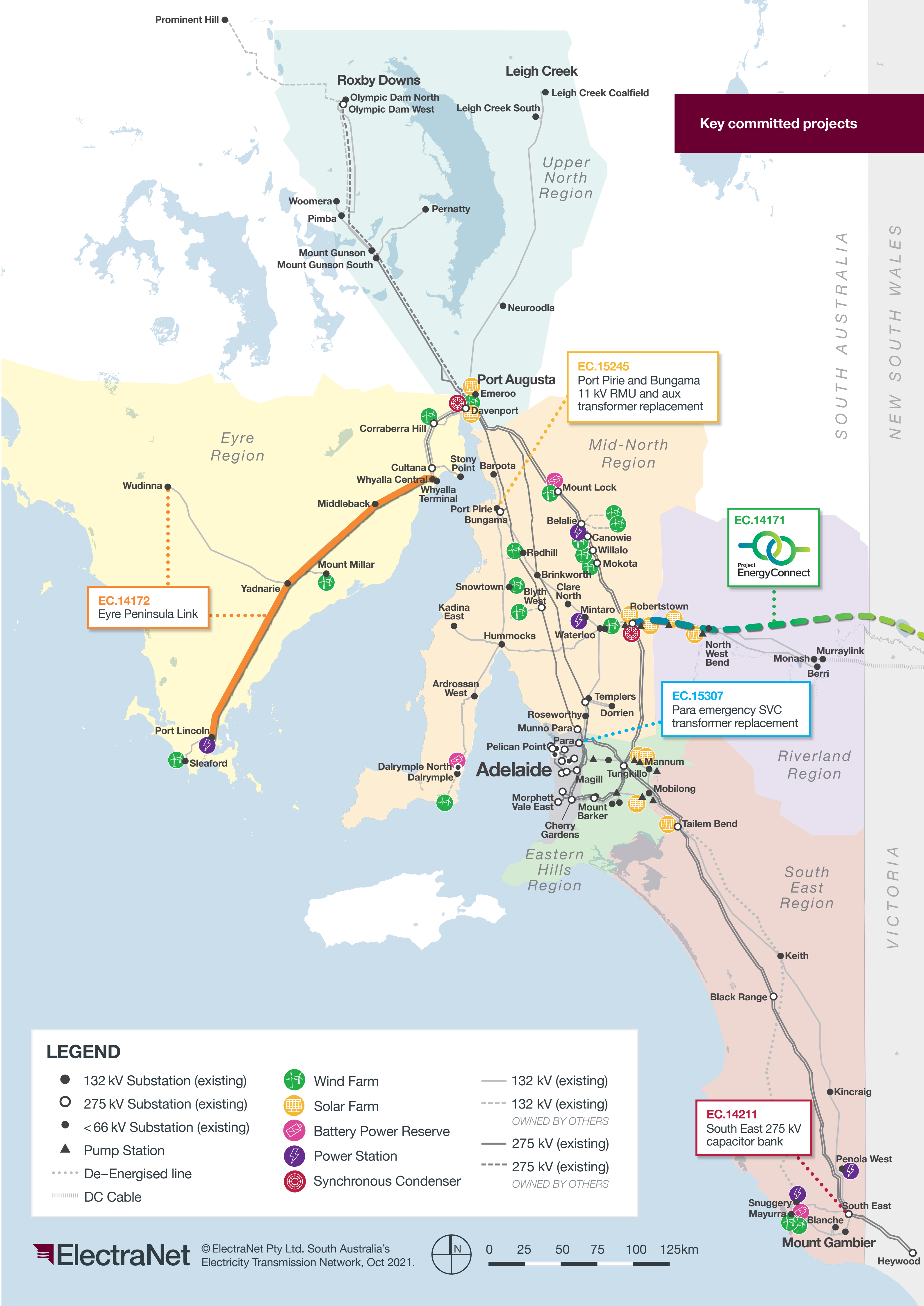
Committed projects as of 29 October 2021

Project Description	Region	Constraint driver and investment type	Planned Asset in service
EC.14245 Port Pirie and Bungama 11kV RMU and Aux Transformer Replacement Replace 11 kV Ring Main Units (RMUs) at Port Pirie and Bungama substations that has been identified as a safety and operational issue.	Mid North	Asset condition and performance Asset renewal	June 2022 (Port Pirie) November 2022 (Bungama)
EC.14127 GE D20 RTU Product Upgrades Extend the operating life of the GE D20 RTU equipment, avoid obsolescence issues and maintain satisfactory performance standards by replacing CPU boards in RTUs at 22 different substation sites.	Various	Asset condition and performance Asset renewal	February 2022
EC.11749 AC Board Replacement 2013 – 2018 Replace and improve AC auxiliary supply equipment, switchboards and cabling at 11 substations that are at the end of technical life.	Various	Asset condition and performance Asset renewal	November 2021
EC.14132 Isolator Status Indication Install status indicators on 54 isolators and 19 earth switches across seven sites, typically in mesh busses, where no status indication is currently installed.	Various	Operational Operational	March 2022
EC.14236 Capacitor Bank Infrastructure Safety Improvement Improve the safety of personnel accessing enclosed high voltage areas having low height high voltage equipment at 18 substations, as far as is reasonably practicable, by: • upgrading fences on low height high voltage equipment to current standards • improving earthling of high voltage equipment within enclosures • upgrading entry points to current standards.	Various	Safety Asset renewal	March 2022
EC.14131 Motorised Isolator LOPA Improvement Modify 876 isolators and replace 33 isolators to provide satisfactory mechanical and electrical isolation lock-off points on all motorised air insulated isolators identified as safety hazards by a Layer of Protection Analysis (LOPA).	Various	Safety Asset renewal	June 2022
EC.15307 Para Emergency SVC Transformer Replacement Replace the Para SVC transformer and auxiliary equipment that was damaged by a transformer fire in July 2020.	Metropolitan	Asset condition and performance Asset renewal	January 2022
EC.14246 Wide Area Protection Scheme (WAPS) Implement a Wide Area Protection Scheme with the use of PMUs to real time monitor and process system parameters for event detection and include dynamic arming of participating loads and battery energy storage systems to enable a proportionate response to specific events to further enhance SA system security.	Various	Stability Operational	October 2022
EC.14047 Transformer Bushing Unit Asset Replacement 2018 – 2023 Replace transformer bushings fitted on 16 power transformers located in nine substations that are at the end of their technical lives and require replacement based on their condition, due to an increasing risk of failure that may result in safety and reliability issues, or in the worst case, catastrophic failure of the transformer and the resultant loss and associated damage.	Various	Asset condition and performance Asset renewal	October 2022
EC.14211 South East 275 kV Capacitor Bank Install an additional 100 Mvar capacitor bank and associated equipment at South East substation to enable power transfers from Victoria to be increased by 30 MW, to enable increased utilisation of the full capability of the Heywood interconnector.	South East	Market benefit (NCIPAP) Augmentation	October 2022

Project Description	Region	Constraint driver and investment type	Planned Asset in service
EC.14172 Eyre Peninsula Link Construct a new double-circuit line from Cultana to Yadnarie initially energised at 132 kV with a rating of about 300 MVA per circuit, with the option to be energised at 275 kV with a rating of about 600 MVA if required in the future. Construct a new double-circuit 132 kV line from Yadnarie to Port Lincoln, rated to about 240 MVA per circuit.	Eyre Peninsula	Reliability Augmentation	December 2022
EC.14081 Line Insulator Systems Refurbishment 2018 – 2023 Refurbish transmission line support systems and extend the life of 18 transmission lines by renewing line asset components.	Various	Asset condition and performance Asset renewal	January 2023
EC.14171 Project EnergyConnect: South Australia to New South Wales interconnector Construct a new 330 kV, 800 MW interconnector from Robertstown in South Australia to Wagga Wagga in New South Wales, via Buronga.	Riverland	Market benefit Augmentation	Stage 1 (Robertstown to Buronga): Second half of 2023 Stage 2 (Buronga to Wagga Wagga): Second half of 2024
EC.14032 Instrument Transformer Unit Asset Replacement Replace instrument transformers at 19 substations which are at the end of their technical life, due to an increased risk of failure which may result in an increasing rate of explosive asset failure causing unpredictable damage resulting in potential substation failure and involuntary load shedding on parts of the network.	Various	Asset condition and performance Asset renewal	June 2023
EC.14033 Circuit Breaker Unit Asset Replacement 2018 – 2023 Replace 15 circuit breakers located in six substations that are at the end of their technical lives and require replacement based on their condition due to an increasing risk of catastrophic failure with consequential safety risks and the potential for involuntary load shedding on parts of the network.	Various	Asset condition and performance Asset renewal	May 2023
EC.14218 Spencer Gulf Emergency Bypass Preparation Undertake preparatory site works and procure spares to support a rapid restoration of Spencer Gulf high tower crossings for the Davenport – Cultana 275 kV transmission lines, which supply the entire Eyre Peninsula region.	Eyre Peninsula	Operational Operational	December 2022
EC.11646 Eyre Peninsula and Upper North Voltage Control Scheme Implement an automated voltage control scheme to ensure the complex voltage interactions throughout the Eyre Peninsula and Upper North regions are managed efficiently.	Eyre Peninsula and Upper North	Power Quality Operational	November 2022
EC.14031 Protection System Unit Asset Replacement Replace protection relays aged between 38 and 60 years old at 23 substations that are at the end of their technical and economic lives, having an increased risk of failure which may result in increased safety and reliability issues and cause involuntary load shedding on parts of the network.	Various	Asset condition and performance Asset renewal	September 2024
EC.14034 Isolator Unit Asset Replacement 2018 – 2023 Remove, and replace where required, approximately 73 isolators at 18 substations that no longer have original manufacturer support and create inventory spares to support the ongoing maintenance of ElectraNet's ageing isolator fleet.	Various	Asset condition and performance Asset renewal	September 2024
EC.14176 Surge Arrestor Unit Asset Replacement 2018 – 2023 Replace porcelain surge arrestors and arcing horns at 18 substations that are at the end of their technical and economic lives due to their increasing risk of failure and potential to cause injury to personnel and collateral damage to other plant within the substation as a result of an explosive failure.	Various	Asset condition and performance Asset renewal	September 2024
EC.14046 AC Board Replacement 2018 – 2023 Replace and improve AC auxiliary supply equipment, switchboards and cabling at 23 substations that are at the end of technical life.	Various	Asset condition and safety Asset renewal	May 2028

6.3 Pending projects

We define pending projects as those projects that have completed the RIT-T or equivalent process but have not yet been fully approved by the ElectraNet Board. We currently have no pending projects.



7 Transmission System Development Plan

This chapter presents the Transmission System Development Plan resulting from our annual planning review, and addresses projected limitations on the South Australian transmission network over the next 10 years.

These developments include projects to meet various needs, such as to:

- **Augment capacity to meet increasing connection point demand (where relevant)**
- **Maintain compliance with technical standards**
- **Maintain system security and operational flexibility**
- **Manage network and asset performance risk**
- **Provide net market benefits by minimising transmission network constraints**

Estimated project costs quoted in this chapter are presented in 2021 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, and the early stages of a project.

Two scenarios have been developed and evaluated as part of ElectraNet's planning process, considering a range of different assumptions about the future development of demand and generation in South Australia. Our planning scenarios were based on the Central Scenario from AEMO's 2020 ISP. The scenarios, together with the range of assumptions, are intended to represent a range of credible potential futures.

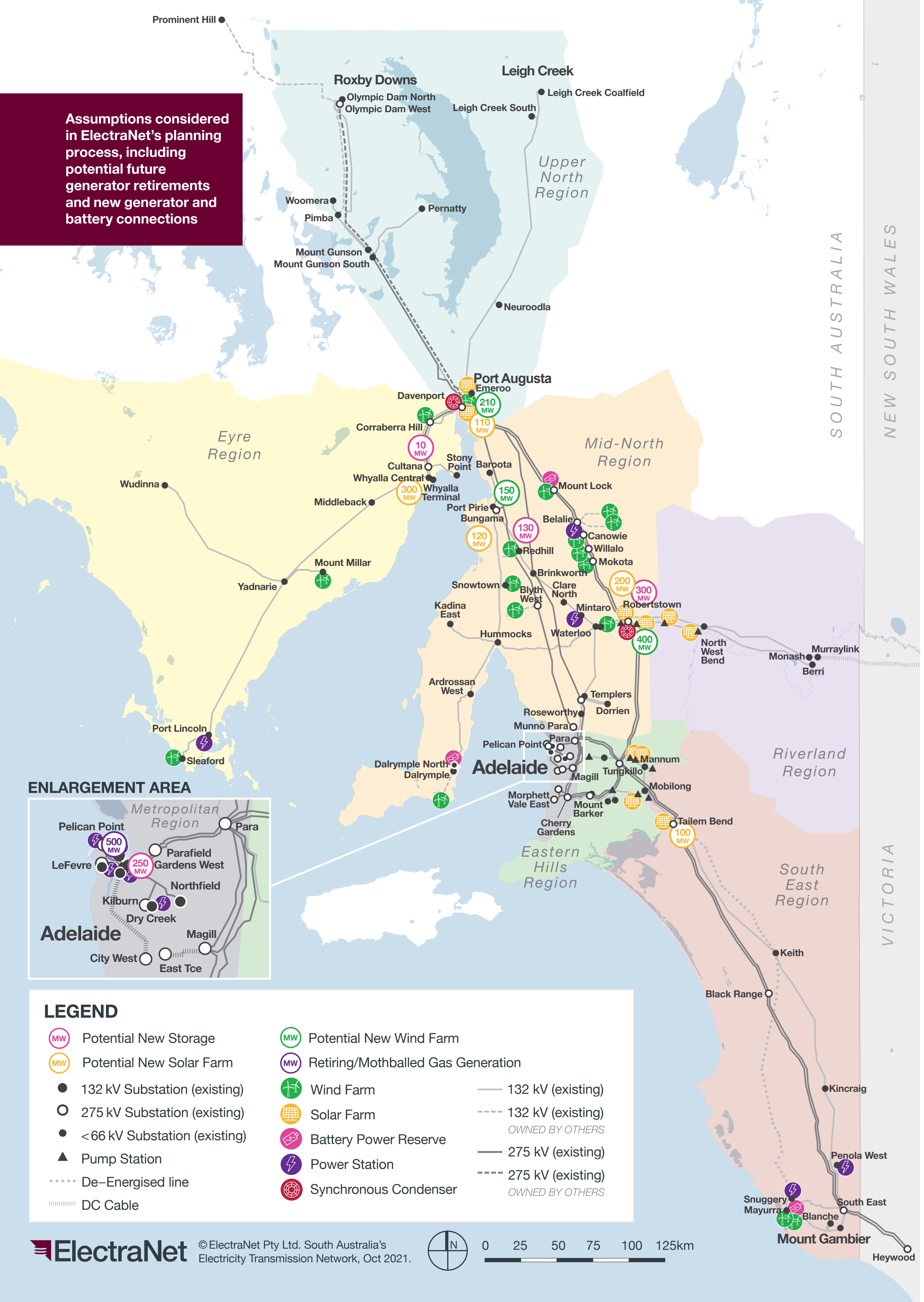
Most scenarios planned for consideration in AEMO's 2022 ISP are more similar to the Step Change scenario from the 2020 ISP. We plan to review the impact of the updated scenarios more fully in 2022, but we currently expect that the impact of the updated ISP scenarios will be greater over the 10-20 year timeframe than in the next 10 years.

The scenarios and assumptions have been characterised in the table below and a range of potential new generation connections over the next 10 years (generic, based on received enquiries and modelling outcomes) are graphically represented overleaf.

Characteristics and assumptions of ElectraNet's planning scenarios

Characteristic	Central scenario	100% net renewables in SA
Connection point demand forecasts	As published in the 2021 connection point data on our Transmission Annual Planning Report webpage[38]	
SA transmission system coincident demand forecasts	AEMO's 2021 ESOO 10% POE maximum demand forecast and 90% POE minimum demand forecast	
Potential new load connections	As shown in map overleaf	As shown in map overleaf
Potential new or retired conventional generators		
Potential new renewable generators		As required to achieve renewable energy generation within South Australia that meets or exceeds South Australian demand

[38] *Web page available at https://www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/*



7.1 Summary of planning and development outcomes

Analysis of the scenarios led to a range of high-level planning outcomes, project recommendations and development outcomes that are required across both scenarios (below). Detailed outcomes are covered in sections 7.3 to 7.10.

Potential projects that may be required to support only one scenario were covered earlier, in section 4.4.

Summary of planning and development outcomes

Planning focus	Key outcomes
National transmission planning	**Project EnergyConnect** Project EnergyConnect involves the construction of a new 330 kV interconnector from Robertstown in South Australia to Wagga Wagga in New South Wales. Transfer capacity will be up to about 800 MW. Implementation of Project EnergyConnect will also increase the maximum amount that can be transferred across the Heywood interconnector to a transfer capacity of up to about 750 MW. Once fully delivered, the full combined transfer limit across both the Heywood and Project EnergyConnect interconnectors will be 1,300 MW into South Australia and 1,450 MW export. In January 2020, the AER published a RIT-T determination including that Project EnergyConnect remained the most "credible option that maximises the net economic benefit" in the NEM, ultimately benefitting electricity consumers. AEMO's 2020 ISP identifies Project EnergyConnect as part of the optimal development path for the NEM. In June 2021, the AER approved Contingent Project Applications from ElectraNet and TransGrid to provide funding for each business to undertake their portion of the works to create Project EnergyConnect. Project EnergyConnect will support Australia's growing renewable energy industry, with new wind and solar projects planned for South Australia, New South Wales and Victoria expected to benefit from the new interconnector. In South Australia, Project EnergyConnect's Environment Impact Statement is currently open for public comment and undergoing assessment by the South Australian Government's Planning and Land Use Services. Subject to receiving all necessary environmental approvals, construction is anticipated to start later this year with commissioning planned to commence in 2023.
System security and power quality	**System strength, inertia and fast frequency response** We have installed synchronous condensers at Davenport and Robertstown in 2021. The installation of these synchronous condensers addressed the system strength and synchronous inertia needs that AEMO identified in 2018 for South Australia. They also contribute to the ongoing provision of adequate voltage control in the Mid North and Upper North of the South Australian transmission system including at times of low demand. Commissioning of the synchronous condensers has allowed the amount of non-synchronous generation that can be dispatched at times of minimum conventional generation in South Australia to be increased from 2,000 MW to 2,500 MW as well as significantly alleviating voltage limits in the Mid North. AEMO has published the 2020 inertia requirements in South Australia, replacing the 2018 inertia requirements. AEMO has determined the secure operating level of inertia for South Australia, proposing fast frequency response (FFR) to be made available for network support on a basis that enables AEMO to determine a reduced inertia shortfall. We have initiated the procurement process and are engaging with the market for the provision of FFR services. **Voltage control** We have identified an emerging need to reduce the system's reliance on dynamic reactive power devices to satisfactorily manage steady-state voltage levels at times of low system demand. The proposed solution is to install a suite of 50-60 Mvar 275 kV reactors at various locations, to maintain an appropriate reserve of dynamic reactive power capability at times of low or negative net system demand. **Power Quality** The changing nature of the power system has impacted overall power quality performance. Ongoing monitoring and supporting studies indicate that mitigation actions may be required at up to four key locations to rectify power quality performance to within technical compliance limits. Further investigation is required to ensure appropriate levels of power quality performance for all network connected customers (load and generation). **Maximum fault levels** Fault levels are forecast to remain within design and equipment limits for the duration of the planning period.

Planning focus	Key outcomes
Connection points	**Eyre Peninsula Link** Construction of Eyre Peninsula Link started in mid-2021. This project will replace the existing 132 kV lines between Cultana and Port Lincoln with a new double-circuit line between Cultana and Yadnarie that is initially energised at 132 kV, but which has the option to be energised at 275 kV if required in the future, and with a new double-circuit 132 kV line between Yadnarie and Port Lincoln. We plan to energise Eyre Peninsula Link by the end of 2022. **Other connection points** Loads at all other connection points are forecast to remain within design and equipment limits for the duration of the planning period.
Market benefit opportunities	A range of projects is proposed to reduce the impact of existing and forecast network constraints to deliver net market benefits. This includes the projects that form ElectraNet's 2018-19 to 2022-23 Network Capability Incentive Parameter Action Plan (NCIPAP). Since 2020, the project to turn in the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo has been retained in our 2018-19 to 2022-23 NCIPAP, instead of being removed as we had indicated in our 2020 Transmission Annual Planning Report that we planned to do.
New connections	The South Australian transmission system continues to have capacity to connect new load, generators, and storage. Generation output may at times be limited by system constraints, particularly at times of very low system demand and at times of coincident high generation output of wind and solar farms. We are aware of significant interest in new generator and load developments, especially in the Mid North, Eyre Peninsula and Riverland regions. We are investigating opportunities to increase transfer capability through the Mid North to allow increased power transfers between these regions and South Australia's load centre in metropolitan Adelaide. Similarly, we are also investigating ways to further increase the transfer capability between the South East region and the Adelaide metropolitan area, to address potential future interest in the South East as indicated in AEMO's 2020 ISP.
Network asset retirements and de-ratings	South Australia's transmission network is older than many others. Our replacement and refurbishment plans are based on our assessment of the condition, risk and performance of the relevant assets. We assess the condition of the various components of each transmission line and substation asset on an ongoing basis through routine inspections and patrols. This information is used to assess how much longer the component can be expected to keep functioning before it fails. In doing this, we consider other information such as failure rates observed elsewhere and environmental conditions surrounding the assets. Based on our assessment of asset condition, risk, cost and performance, we plan to address emerging condition needs for a range of assets on South Australia's electricity transmission network during the planning period. Our major line refurbishment projects and substation asset replacement projects focus on the key components of these assets on the network.
Emergency control schemes	We are collaborating with AEMO to augment the existing SIPS to a more sophisticated WAPS. The final scheme is expected to be commissioned by October 2022. As part of Project EnergyConnect a Special Protection Scheme will be implemented to cater for the non-credible loss of either Project EnergyConnect or Heywood. The WAPS will also be reviewed when Project EnergyConnect is implemented. The 2020 PSFRR identified risks relating to the non-credible separation of South Australia under conditions during which distributed PV generation reduces the net load on UFLS circuits, reducing the amount of load that is shed when the UFLS activates, thereby reducing the effectiveness of the scheme. The PSFRR indicates that AEMO intends to seek Reliability Panel declaration of a protected event for non-credible separation of South Australia at certain times, allowing action to be taken whenever the non-credible separation could lead to an under-frequency event that has a material risk of resulting in cascading failure, including stakeholder suggestions for additional options that should be considered for management of the proposed protected event. With the rapid evolution of the Power System, we expect that the need for emergency control schemes to manage both credible and non-credible system events will continue to grow. We are engaging with AEMO on work for the 2022 PSFRR. From 2023, the PSFRR will be replaced with a broader General Power System Risk Review (GPSRR). We are assessing the impact that this will have on our planning processes.

7.2 Committed urgent and unforeseen investments

ElectraNet reports any investments that have been made since the publication of the last Transmission Annual Planning Report that would have been subject to the RIT-T had they not been required to address an urgent and unforeseen network issue. We have not made any such investments.

7.3 Interconnector and Smart Grid planning

ElectraNet is progressing projects and investigating opportunities to increase interconnector capacity between South Australia and the rest of the NEM, including the development of Project EnergyConnect and the deployment of "smart grid" technology such as wide area monitoring and protection schemes (table and map overleaf).

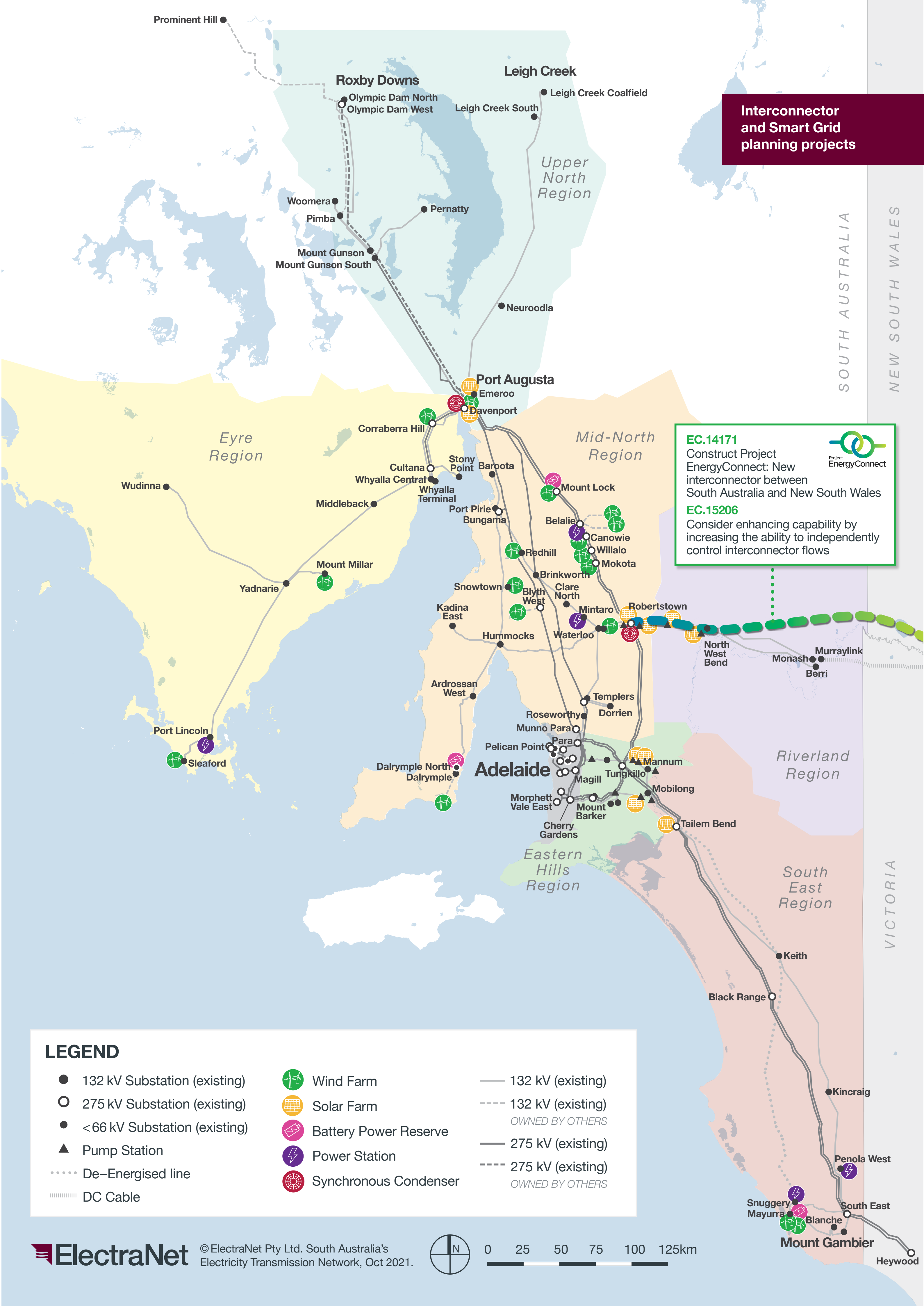
Consistent with the results of AEMO's 2020 ISP, we are developing Project EnergyConnect to address emerging South Australian and National transmission planning needs.

We are also progressing the upgrade of our SIPS to a more sophisticated WAPS, which will satisfy the requirements of AEMO's 2018 Power System Frequency Review.

In the mid-2020s we propose to further upgrade the WAPS to a more extensive wide area monitoring scheme. We are considering opportunities to further increase the firm transfer capacity of Project EnergyConnect and the Heywood interconnector, for example by installing dynamic voltage control devices, series capacitors or other flow control devices.

Committed and proposed projects to strengthen interconnection, or improve transfer capability by the application of smart grid technology

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14246 Wide Area Protection Scheme (WAPS) Estimated cost: **$8-10 million** Status: **Committed** Implement a Wide Area Protection Scheme with the use of PMUs to real time monitor and process system parameters for event detection, and include dynamic arming of participating loads and battery energy storage systems to enable a proportionate response to specific events to further enhance SA system security. ElectraNet does not envisage that this project will impact inter-regional transfer.	All	Stability Operational	October 2022
EC.14171 Project EnergyConnect: New interconnector between South Australia and New South Wales Estimated cost: In May 2021 the AER approved the ElectraNet and TransGrid Contingent Project Applications with a total cost of **$2.27 billion**, of which works in South Australia comprise **$457 million** Status: **Committed** Construct a new 330 kV, 800 MW interconnector from Robertstown in South Australia to Wagga Wagga in New South Wales, via Buronga and strengthen the link between Buronga and Red Cliffs (Victoria). This project will increase the full combined transfer limit across both the Heywood and Project EnergyConnect interconnectors to 1,300 MW import into South Australia and 1,450 MW export. ElectraNet envisages that this project will impact inter-regional transfer.	Main Grid	Market benefit Augmentation	Stage 1 (Robertstown to Buronga): Second half of 2023 Stage 2 (Buronga to Wagga Wagga): Second half of 2024
EC.15272 Wide Area Monitoring Scheme 2023-2028 Estimated cost: **$5-15 million** Status: **Proposed** Expand the existing WAMS by installing phasor measurement units (PMUs) as required by AEMO at candidate sites across the SA transmission network. The scope of works includes installing hardware and software to integrate new PMUs to existing systems and deploy associated software application analytical tools that will be used to analyse the data collected. The candidate sites cover a range of network locations listed below: • Main transmission network (incremental to existing PMU network) – will monitor the performance of the main transmission network and identify emerging power system challenges • Generator/BESS sites – will monitor the dynamic response of major generators and batteries • Regional Load sites at the periphery of the system – monitoring will help understanding of load dynamics for benchmarking power system models and identification of emerging challenges in the power system • Metro Loads incorporating significant DER Feed-in – monitoring will help understand the response of DER following-system disturbances for benchmarking power system models, network planning and accurate constraint development ElectraNet does not envisage that this project will impact inter-regional transfer.	All	Stability Operational	2024 – 2028
EC.15206 Project EnergyConnect Upgrade Estimated cost: **$100-150 million** Status: **Being considered for proposal as a contingent project** Improve the ability to independently control power flows across Project EnergyConnect. The combined transfers would be lifted with a control scheme integrating detailed monitoring of the South Australian grid and automated analytics that determine on immediate snapshots the ability of the grid to withstand the loss of either path, leveraging the expanded WAMS and PEC SPS, and integrating the state of charge of participating batteries to immediately offset the loss of one HVAC interconnector path without compromising the remaining path. ElectraNet envisages that this project will impact inter-regional transfer.	Main Grid	Market benefit Augmentation	When or if shown to deliver net market benefits



7.4 System security, power quality and fault levels

A secure power system needs adequate levels of system strength, inertia and voltage control, which in the past have been provided by synchronous power generation. We have proposed several projects to meet system strength, inertia and voltage control needs (map and table overleaf).

System strength relates to the ability of a power system to manage fluctuations in supply or demand while maintaining stable voltage levels. Inertia relates to the ability of a power system to manage fluctuations in supply or demand while maintaining stable system frequency.

AEMO published 2020 inertia requirements in South Australia, replacing the 2018 inertia requirements. AEMO has determined the secure operating level of inertia for South Australia, proposing fast frequency response (FFR) be made available to address the declared inertia shortfall. We have initiated the procurement process and are engaging with the market for the provision of FFR services.

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

Based on the outcomes of AEMO's 2020 ISP and confirmed by our own modelling, the total of conventional generation in South Australia is expected to reduce over the next 10 years. Substation fault levels were assessed to ensure they will remain within design and equipment limits.

Minimum demands on South Australia's electricity transmission network typically occur in the middle of mild, sunny weekend days or public holidays (chapter 3). Times of low demand typically correlate with times of high voltage levels on the transmission system.

We have assessed the ability of the network to deliver minimum demand while maintaining system voltage levels within equipment limits with all system elements in service and allowing for any one item of plant to be out of service.

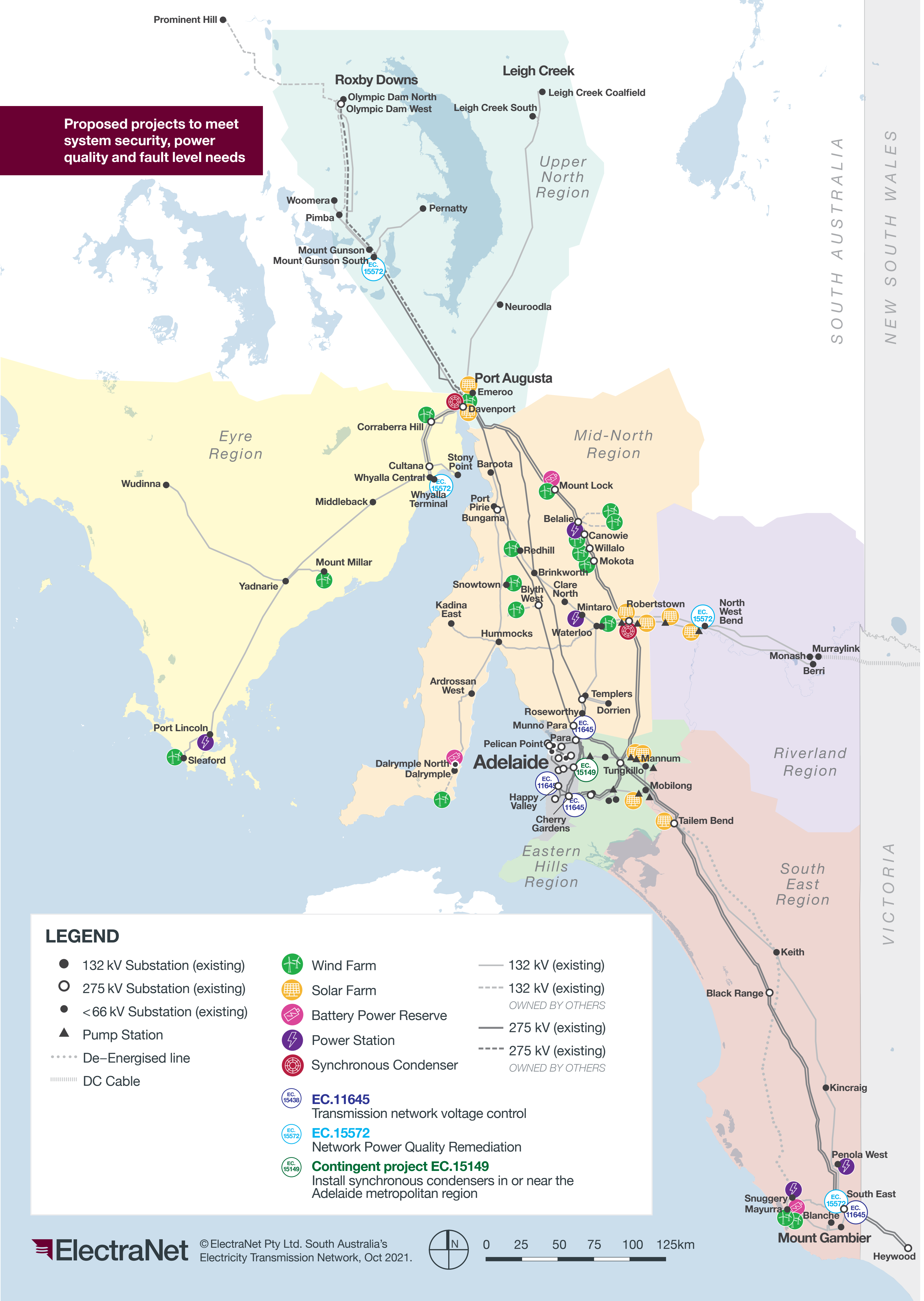
The installation of synchronous condensers at Davenport and Robertstown during 2021 has maintained and enhanced the ability to adequately control system voltage levels. Additional investment in reactors is forecast to be needed in 2024 to maintain the ability of the system to control system voltage levels within equipment limits as the penetration of distributed solar PV generation continues to the extent that it delivers a net infeed to the transmission system.

The changing nature of the power system has impacted overall power quality performance. Ongoing monitoring and supporting studies indicate that mitigation actions may be required at up to four key locations to rectify power quality performance to within compliance limits. Further investigation is required to ensure appropriate levels of power quality performance for all network connected customers (load and generation).

Expected maximum and minimum fault levels at each connection point are available from the supporting data published on our Transmission Annual Planning Report web page.[39]

[39] Our Transmission Annual Planning Report web page is available at https://www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/.

Robertstown Synchronous Condenser



Projects proposed to maintain or enhance system security or power quality

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15438 Transmission Network Voltage Control Estimated cost: **$40-60 million** Status: **Proposed** Install a total of four 60 Mvar 275 kV reactors around the Adelaide metropolitan region at Happy Valley, Munno Para and Cherry Gardens, and a single 50 Mvar 275 kV reactor at South East. The installations will include associated works for reactor connection and switching, monitoring and control, system protection, and site civil works. These and other reactive and voltage control devices on the main 275 kV transmission network will be upgraded to enable coordinated automatic switching of existing and planned reactive power devices. This will require the installation and modification of secondary plant items for monitoring, control and protection covering multiple substation sites including automating Onload Tap Changer operation at SA Power Networks connection points. We plan to commence a RIT-T for this project in 2022. ElectraNet does not envisage that this project will impact inter-regional transfer.	Main Grid	Reactive support Augmentation	2024
EC.15572 Network Power Quality Remediation Estimated cost: **$30-60 million** Status: **Being considered for proposal as a contingent project** Install relevant equipment to ensure maintain power quality is maintained for customers across the transmission network in relation to voltage harmonic and flicker requirements in line with accepted standards. ElectraNet does not envisage that this project will impact inter-regional transfer.	Various (depending on the outcome of monitoring)	Compliance Augmentation	2024 – 2028 (if shown to be required)
EC.15149 Install synchronous condensers in or near the Adelaide metropolitan region Estimated cost: **$80-120 million** Status: **Being considered for proposal as a contingent project** Install additional synchronous condensers or other source of fast voltage control (e.g. STATCOM) in or near the Adelaide metropolitan region to increase system strength and dynamic voltage support ElectraNet envisages that this project will impact inter-regional transfer.	Main Grid	Compliance Augmentation	2024 – 2028 (if shown to deliver net market benefits or due to revised system security framework)

7.5 Capacity and Renewable Energy Zone development

We are progressing the development of Eyre Peninsula Link to continue to efficiently meet reliability standards on the Eyre Peninsula, and have also identified potential projects to provide capability for future new customers and generators (map and table overleaf).

ElectraNet annually compares connection capability against forecast connection point demand, considering the redundancy requirements specified for each connection point in the South Australian Electricity Transmission Code (ETC, redundancy requirements summarised in Appendix C section C2.1). This is coordinated through joint planning with SA Power Networks, in which connection point projects are considered, proposed, and planned (Appendix B).

If a new large customer connects on the Eyre Peninsula in the future it may become necessary to upgrade the Cultana to Yadnarie section of Eyre Peninsula Link from 132 kV to 275 kV operation.

We have also assessed the capability of the network to accommodate new generator connections. In doing so we consider the REZs that AEMO identifies for potential development in the ISP along with the results of our own analysis to identify potential projects to provide additional capacity for new generator connections.

Given the continuing high level of interest in new generator connections in South Australia, we consider that the future developments identified in the 2020 ISP could be needed much earlier than indicated.

As outlined in section 2.1 of this report, AEMO's 2020 ISP forecast that network expansion to release REZ capacity in the South East of South Australia will be needed in the late 2030s, or in 2030-31 if the Step Change scenario eventuates. To meet this need we are proposing a contingent project to string the vacant 275 kV circuit between Tailem Bend and Tungkillo to increase transfer capacity between the South East and the Adelaide metropolitan load centre, including additional dynamic reactive support if needed to improve dynamic voltage stability.

The 2020 ISP also forecast a need to alleviate constraints between Robertstown, Davenport and Adelaide in 2034-35 or 2035-36.[43] To meet this potential need if confirmed we may be required to pursue a contingent project, potentially to be implemented in stages. Options include:

- installing a second 275/132 kV transformer at Templers West and decommission the existing Templers to Waterloo 132 kV line
- increasing transfer capacity between Robertstown and Adelaide, perhaps by building new double circuit 275 kV lines between Robertstown and Para via Templers West
- increasing transfer capacity by constructing new 275 kV lines between Davenport and Robertstown, Para or Templers West.

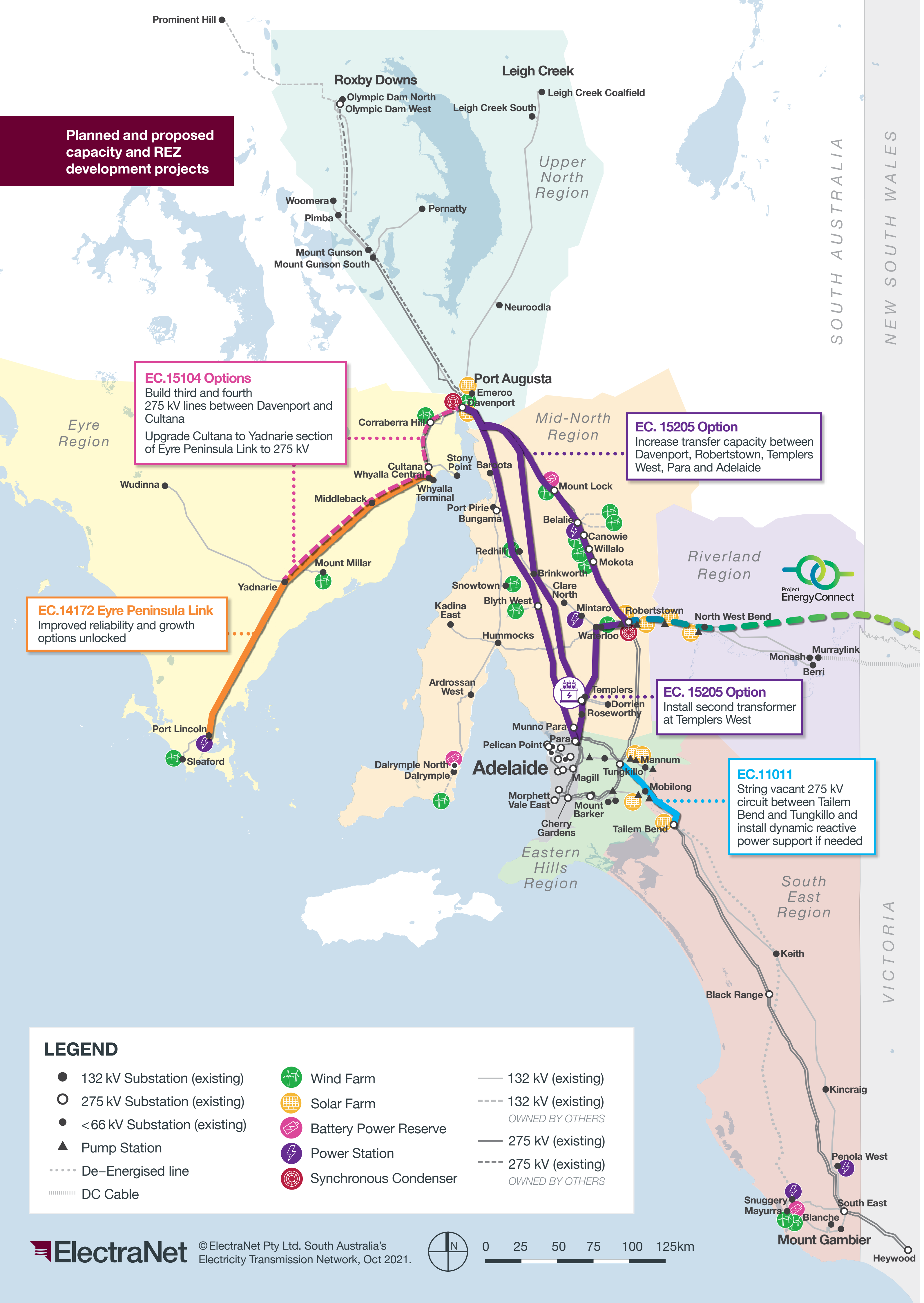
We have also proposed other projects that might be required to release additional capacity for new generator connections in the South East and on the Eyre Peninsula.

Projects to improve generator or load hosting capacity in the Upper North are included in the current regulatory control period as contingent projects.

[43] *AEMO's Final 2020 Integrated System Plan, page 91. Available at* https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

City West Substation

Planned and proposed capacity and REZ development projects



Projects committed or proposed to meet capacity or REZ development needs

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14172 Eyre Peninsula Link Estimated cost: **$300-330 million** Status: **Committed** Replace the existing Cultana to Yadnarie 132 kV single circuit transmission line with a new double-circuit line initially energised at 132 kV with a rating of about 300 MVA, with the option to be energised at 275 kV with a rating of about 600 MVA if required in the future. Replace the existing Yadnarie to Port Lincoln 132 kV single circuit transmission line with a new double-circuit 132 kV line with a rating of about 240 MVA. Install a 10 Mvar 132 kV reactor at Wudinna to offset the increased capacitive charging from the new 132 kV lines. ElectraNet does not envisage that this project will impact inter-regional transfer.	Eyre Peninsula	Reliability Augmentation	December 2022
EC.15104 Eyre Peninsula upgrade Estimated cost: **$50-150 million** Status: **Being considered for proposal as a contingent project** Upgrade the operating voltage of the committed new Cultana to Yadnarie transmission lines from 132 kV to 275 kV if potential large loads connect on the Eyre Peninsula. If needed, construct additional double circuit 275 kV line between Davenport and Cultana. ElectraNet does not envisage that this project will impact inter-regional transfer.	Eyre Peninsula	Capacity Augmentation	2024 – 2028 (if required to facilitate large new customer connections on Eyre Peninsula)
EC.11011 Upper South East network augmentation Estimated cost: **$30-50 million** Status: **To be considered for proposal as a contingent project** String the vacant third 275 kV circuit between Tailem Bend and Tungkillo and install static and dynamic reactive compensation if needed to increase transfer capability between the South East and the Adelaide metropolitan area. ElectraNet envisages that this project may impact inter-regional transfer.	Eastern Hills	Market benefits Augmentation	2029 – 2033 (or earlier, if shown to deliver net market benefits)
EC.15205 Increase transfer capacity between Robertstown, Davenport and Adelaide Estimated cost: **$200-250 million** Status: **Being considered for proposal as a contingent project** Increase transfer capacity between the northern parts of the South Australian electricity transmission network and the Adelaide metropolitan load centre in stages. Options include: • Install a second 275/132 kV transformer at Templers West and decommission the Templers to Waterloo 132 kV line, to provide an initial increase in transfer capacity between Robertstown in the Mid North and the Adelaide metropolitan load centre • Significantly increase transfer capacity between Robertstown and Adelaide by building new double circuit 275 kV lines between Robertstown and Templers West, and rebuilding the Templers West to Para 275 kV line as a new double circuit 275 kV line • Significantly increase transfer capacity between Davenport and Adelaide by building new double circuit 275 kV lines between Davenport and Robertstown, Templers West or Para. ElectraNet envisages that this project may impact inter-regional transfer.	Mid North	Market benefits Augmentation	Between the mid-2020s and late-2030s (if shown to deliver net market benefits)
EC.14212 Upper North region eastern 132 kV line reinforcement Estimated cost: **$60 million** Status: **Contingent – refer to Appendix E for trigger** Uprate or rebuild the Davenport to Leigh Creek 132 kV line and establish associated substation assets (including reactive support). ElectraNet does not envisage that this project will impact inter-regional transfer.	Upper North	Capacity Augmentation	Not expected to proceed
EC.14093 Upper North region western 132 kV line reinforcement Estimated cost: **Less than $110 million** Status: **Contingent – refer to Appendix E for trigger** Rebuild the Davenport to Pimba 132 kV line and establish associated substation assets (including reactive support). ElectraNet does not envisage that this project will impact inter-regional transfer.	Upper North	Capacity Augmentation	Not expected to proceed

7.6 Market benefits and opportunities

ElectraNet monitors congestion on the South Australian transmission system (section 4.1.1). We also consider information regarding future likely generator and load connections, along with AEMO's ISP, to predict new constraints that may develop in future years.

Many of the projects discussed in preceding sections also provide net market benefits, for example by improving customer reliability or reducing congestion on the transmission system. In addition, we also plan to complete projects that form part of our 2018-19 to 2022-23 NCIPAP (table and map overleaf).

We are also considering projects for inclusion in our 2023-24 to 2027-28 NCIPAP. Projects currently proposed include:

- Uprating 275 kV lines to release power transfer capacity
- Installing a capacitor to increase Murraylink transfer capacity
- Implementing 10-band transmission line ratings to release power transfer capacity
- Implementing a tripping scheme to allow more efficient use of distributed renewable resources.

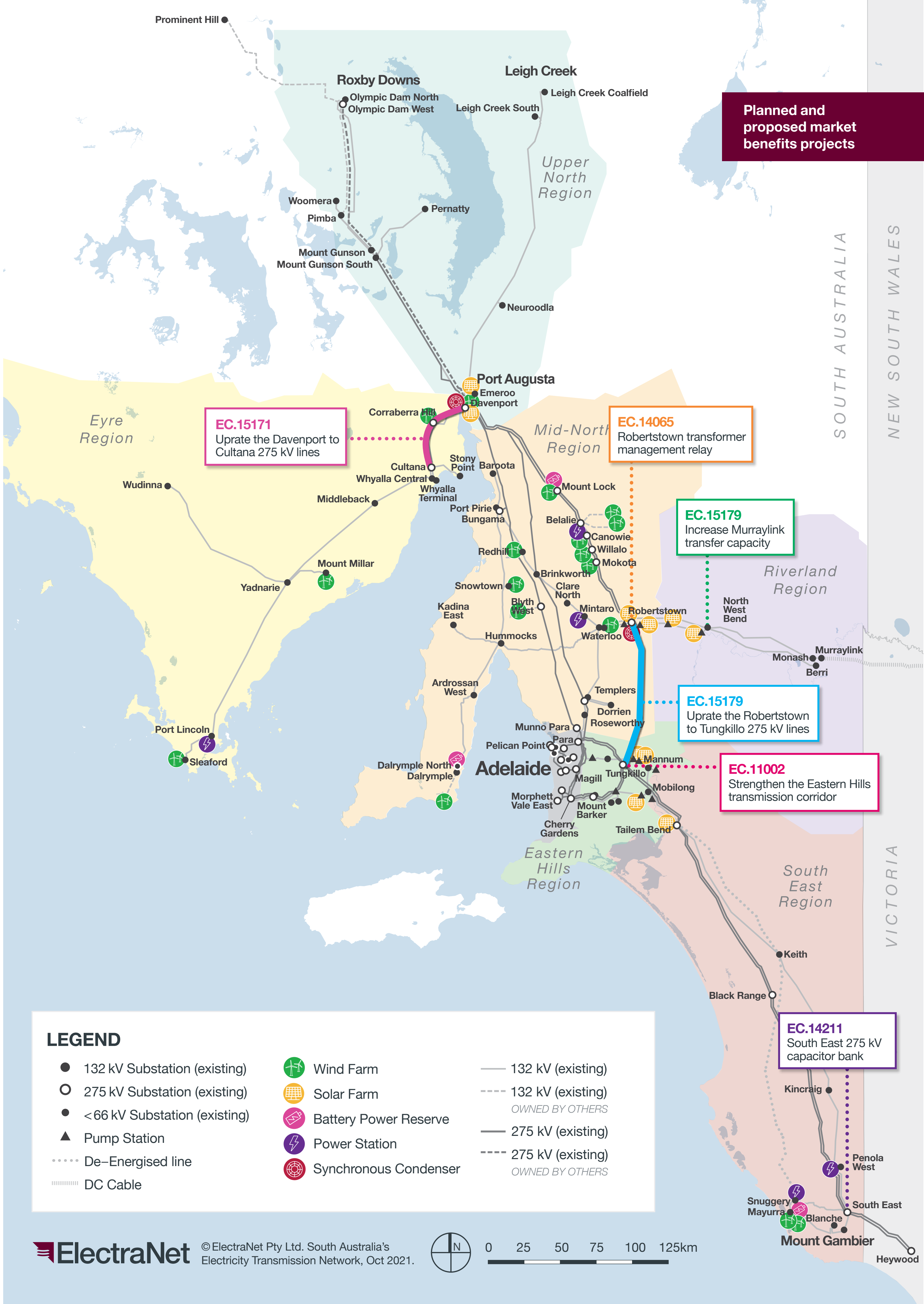
Further detail is available from our Transmission Annual Planning Report web page.[41]

[41] *Our Transmission Annual Planning Report web page is available at https://www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/.*

Robertstown Synchronous Condenser

Projects committed, planned and being considered to address market benefit opportunities

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14211 South East 275 kV capacitor bank Estimated cost: **$4-6 million** Status: **Committed** Further alleviate forecast congestion on the Heywood interconnector by installing an additional 100 Mvar 275 kV switched capacitor at South East substation to 'firm up' transfer capability by maintaining voltage stability at higher transfer levels. ElectraNet envisages that this project will impact inter-regional transfer.	South East	Market benefits (NCIPAP) Augmentation	October 2022
EC.14065 Robertstown transformer management relay Estimated cost: **Less than $5 million** Status: **Planned** Alleviate constraints on Murraylink interconnector by installing transformer management relays and bushing monitoring equipment to enable the application of short term ratings to the Robertstown 275/132 kV transformers. ElectraNet envisages that this project will impact inter-regional transfer.	Mid North	Market benefits (NCIPAP) Augmentation	June 2022
EC.11002 Strengthen the Eastern Hills transmission corridor Estimated cost: **$5-6 million** Status: **Planned** Connect the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo. ElectraNet envisages that this project will impact inter-regional transfer.	Eastern Hills	Market Benefits Augmentation	November 2022
EC.15179 Uprate Robertstown – Tungkillo 275 kV lines Estimated cost: **$2.5 million** Status: **Being considered for inclusion in our 2023-24 to 2027-28 NCIPAP** Alleviate forecast congestion between Robertstown and Tungkillo by uprating the Robertstown to Tungkillo 275 kV lines to 120 °C design clearances. ElectraNet envisages that this project may impact inter-regional transfer.	Eastern Hills	Market benefits (NCIPAP) Augmentation	2024 –2028
EC.15171 Uprate Davenport - Cultana 275 kV lines Estimated cost: **$2 million** Status: **Being considered for inclusion in our 2023-24 to 2027-28 NCIPAP** Alleviate forecast congestion between Cultana and Davenport by removing plant and equipments limitations at either end of the Cultana to Davenport 275 kV lines to release the full design capacity of the lines. ElectraNet envisages that this project will impact intra-regional transfer, but not inter-regional transfer.	Eyre Peninsula	Market benefits (NCIPAP) Augmentation	2024 –2028
EC.15175 Increase Murraylink transfer capacity Estimated cost: **$5.3 million** Status: **Being considered for inclusion in our 2023-24 to 2027-28 NCIPAP** Alleviate forecast congestion on the Murraylink interconnector at times of high export by installing a 132 kV capacitor bank at North West Bend and upgrade the existing runback control scheme to include bi-directionality and allow it to run forward if required. ElectraNet envisages that this project will impact inter-regional transfer.	Riverland	Market benefits (NCIPAP) Augmentation	2024 –2028
EC.15571 10-band rating NCIPAP project Estimated cost: **$6 million** Status: **Being considered for inclusion in our 2023-24 to 2027-28 NCIPAP** Alleviate constraints across the South Australian electricity transmission system by delivering a package of works to replace the existing 3-band rating by 10-band rating. ElectraNet does not envisages that this project will impact inter-regional transfer.	All	Market benefits (NCIPAP) Augmentation	2024 –2028
EC.15182 Munno Para control scheme (NCIPAP transformer tripping scheme) Estimated cost: **About $1 million** Status: **Being considered for inclusion in our 2023-24 to 2027-28 NCIPAP** Alleviate constraints on generation in the north of South Australia by implementing a control scheme to alleviate forecast post-contingent overloads of SA Power Networks' Munno Para to Elizabeth Downs 66 kV line if an outage of the Munno Para to Para 275 kV line was to occur at times of high generation in the north of South Australia.	Metropolitan	Market benefits (NCIPAP) Augmentation	2024 –2028



7.7 Network asset retirements and replacements

ElectraNet carries out projects that are planned to address needs that arise from planned retirements of assets, for example due to condition (table below).

Projects are listed in this section if they are subject to the RIT T, or if they would have been subject to the RIT-T if they had not already been committed by 30 January 2018.

The replacement of a power transformer based on condition provides an opportunity to review the appropriate size and need for any replacement transformer based on forecast demand. This can impact the capacity of the relevant substation. Because of this, projects that relate to the replacement of a power transformer are listed here even if their estimated cost is below the RIT-T threshold.

Further details, including for projects with costs that are lower than the RIT-T cost threshold, are available from our Transmission Annual Planning Report web page.[42]

We do not envisage that any of these projects will impact inter-network transfer.

Projects committed, planned and proposed to address asset retirement and replacement needs

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14049 Leigh Creek South transformer replacement Estimated cost: **$4-6 million** Status: **Planned** Replace the two existing 132/33 kV 5 MVA transformers, assessed to be at the end of their technical life with a corresponding high risk of failure, and the two SA Power Networks 33/11 kV transformers with a single new 5 MVA 132/11 kV transformer.	Upper North	Asset condition and performance Asset renewal	November 2023
EC.14081 Line Insulator Systems Refurbishment 2018-19 to 2022-23 Estimated Cost: **$50-60 million** Status: **Committed** Program to refurbish transmission line support systems and extend the life of 18 transmission lines by renewing line asset components, for the following lines: • Torrens Island – New Osborne 66 kV No. 3 • Torrens Island – New Osborne 66 kV No. 4 • Davenport – Leigh Creek 132 kV • Keith – Kincraig 132 kV • Kincraig – Penola West 132 kV • Murray Bridge Hahndorf Pump Station No. 3 – Back Callington 132 kV • North West Bend – Monash 132 kV No. 1 • South East – Mt Gambier 132 kV • Waterloo – Mintaro 132 kV • Cherry Gardens – Happy Valley 275 kV • Para – Munno Para 275 kV • Para – Robertstown 275 kV • Para – Tungkillo 275 kV • Parafield Gardens West – Para 275 kV • Pelican Point – Parafield Gardens West 275 kV • Torrens Island – Cherry Gardens 275 kV • Torrens Island – Magill 275 kV • Torrens Island – Para 275 kV No. 4	Various	Asset condition and performance Asset renewal	January 2023
EC.14046 AC Board Replacement 2018-19 to 2022-23 Estimated cost: **$20-25 million** Status: **Committed** Program to replace and improve AC auxiliary supply equipment, switchboards and cabling at seventeen substations across the South Australian electricity transmission system that have been assessed to be at the end of their technical and economic lives. This project includes the replacement of assets at the following sites: Berri, Blanche, Davenport, East Terrace, Hummocks, Kanmantoo, Kilburn, Kincraig, LeFevre, Leigh Creek South, Mobilong, Morphett Vale East, Monash, Mount Gambier, Murray Bridge-Hahndorf No. 1 Pump Station, Murray Bridge-Hahndorf No. 2 Pump Station, Murray Bridge-Hahndorf No. 3 Pump Station, Tailem Bend, Parafield Gardens West, Penola West, Pimba, Robertstown, Stony Point We completed a RIT-T for this program of work by publishing a PACR on 14 January 2020.	Various	Asset condition and performance Asset renewal	May 2028
EC.14084 Line Conductor and Earthwire Refurbishment 2018-19 to 2022-23 Program Estimated cost: **$24-28 million** Status: **Planned** Program of projects to replace transmission line conductors and earthwire to extend the life of seven 132 kV transmission lines in the Mid North and Riverland: • Waterloo – Waterloo East • Waterloo East – Morgan Whyalla Pump Station #4 • Morgan Whyalla Pump Station #4 – Robertstown • Robertstown – Morgan Whyalla Pump Station #3 • Morgan Whyalla Pump Station #3 – Morgan Whyalla Pump Station #2 • Morgan Whyalla Pump Station #2 – Morgan Whyalla Pump Station #1 • Morgan Whyalla Pump Station #1 – North West Bend As the individual line projects do not exceed $6 million in estimated cost, we do not plan to apply the RIT-T to these planned investments.	Mid North and Riverland	Asset condition and performance Asset renewal	May 2025
EC.14077 Mannum transformer nos. 1 and 2 replacement Estimated cost: **$6-12 million** Status: **Planned** Replace the two existing 20 MVA transformers, assessed to be at the end of their technical life with a corresponding high risk of failure, with two new 25 MVA 132/33 kV transformers (nearest ElectraNet standard size). We plan to initiate a RIT-T prior to commitment.	Eastern Hills	Asset condition and performance Asset renewal	January 2025
EC.15060 Circuit breakers unit asset replacement 2023-24 to 2027-28 Estimated cost: **$15-20 million** Status: **Proposed** Replace and improve 31 circuit breakers at 13 substations across the South Australian electricity transmission system that have been assessed to be at the end of their technical and economic lives during the 2023-24 to 2027-28 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2024 –2028
EC.15279 Emergency unit asset replacement 2023-24 to 2027-28 Estimated cost: **$8-12 million** Status: **Proposed** Emergency replacement of individual assets is undertaken for assets that fail unexpectedly, to meet reliability standards. The average annual value of stock turn-over is about $2m.	Various	Asset condition and performance Asset renewal	2024 –2028
EC.15043 AC Board unit asset replacement 2023-24 to 2027-28 Estimated cost: **$6-12 million** Status: **Proposed** Replace and improve six AC auxiliary supply systems located at six substations across the South Australian electricity transmission system to be at end-of-life during the 2023-24 to 2027-28 regulatory control period due to increased risk of unsafe access, mal-operation and unplanned outages. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2024 –2028
EC.15233 Transmission line insulation system refurbishment 2023-24 to 2027-28 Estimated cost: **$25-40 million** Status: **Proposed** Implement a program to replace about 2775 insulator strings on 779 structures with equivalent insulation and associated hardware on 14 transmission lines across the network that have been assessed to be at end-of-life during the 2023-24 to 2027-28 regulatory control period, to renew line asset components and extend line life. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2024 –2028
EC.15239 F1803 Hummocks - Ardrossan West 132kV Line Refurbishment Estimated cost: **$15-25 million** Status: **Proposed** Replace line conductor, earthwire and insulator strings for the entire Hummocks to Ardrossan West 132 kV line, which has been assessed to be at end-of-life during the 2023-24 to 2027-28 regulatory control period, to renew line asset components and extend line life. We plan to initiate a RIT-T prior to commitment.	Mid North and Riverland	Asset condition and performance Asset renewal	2024 –2028

[42] *Our Transmission Annual Planning Report web page is available at www.electranet.com.au/xxxxx.*

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15432 F1802 Bungama - Port Pirie 132kV Line Refurbishment Estimated cost: **$5-10 million** Status: **Proposed** Decommission the existing Port Pirie to Bungama 132 kV line, which has been assessed to be at end-of-life during the 2023-24 to 2027-28 regulatory control period, and replace with a new 132 kV line alongside the existing easement. We plan to initiate a RIT-T prior to commitment.	Mid North	Asset condition and performance Asset renewal	2029 – 2033
EC.14090 Mount Gambier transformer 1 replacement Estimated cost: **$4-6 million** Status: **Planned** Replace the existing 50 MVA 132/33 kV transformer, assessed to be at the end of its technical life with a corresponding high risk of failure, with a new 25 MVA transformer. A size of 25 MVA has been chosen to match the other 132/33 kV transformer at Mount Gambier, and provides capacity to meet the forecast demand at Mount Gambier connection point. The project has been deferred until the 2028-29-2032-33 period as the transformer is having minor refurbishment works undertaken in the current period to extend its service life.	South East	Asset condition and performance Asset renewal	Project deferred until 2029 – 2033 period
EC.15069 Circuit breakers unit asset replacement 2028-29 to 2032-33 Estimated cost: **$6-10 million** Status: **Proposed** Replace and improve circuit breakers across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2028-29 to 2032-33 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029 – 2033
EC.15295 Emergency unit asset replacement 2028-29 to 2032-33 Estimated cost: **$8-12 million** Status: **Proposed** Emergency replacement of individual assets is undertaken for assets that fail unexpectedly, to meet reliability standards. The average annual value of emergency replacement is about $2 million.	Various	Asset condition and performance Asset renewal	2029 – 2033
EC.15042 AC Board unit asset replacement 2028-29 to 2032-33 Estimated cost: **$8-15 million** Status: **Proposed** Replace and improve AC auxiliary supply equipment, switchboards and cabling at seventeen substations across the South Australian electricity transmission system that will be assessed to be at the end of their technical and economic lives during the 2028-29 to 2032-33 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029 – 2033
EC.15251 Transmission line insulation unit asset replacement 2028-29 to 2032-33 Estimated cost: **$12-20 million** Status: **Proposed** Refurbish transmission line insulator systems across the network that will be assessed to be at end-of-life during the 2028-29 to 2032-33 regulatory control period, to renew line asset components and extend line life. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029 – 2033
EC.15253 Transmission line conductor unit asset replacement 2028-29 to 2032-33 Estimated cost: **$12-20 million** Status: **Proposed** Replace transmission line conductor and earthwire for components that will be assessed to be at end-of-life during the 2028-29 to 2032-33 regulatory control period, to renew line asset components and extend line life. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029 – 2033

7.8 Network asset ratings

We are continually exploring ways to improve the capacity of our network to supply additional customer load and enable connected generators to access the market. To support this, we have developed a Plant and Line Rating Strategy that describes how network and public risk can be understood and mitigated, while maximising network utilisation and capacity.

The Strategy proposes initial refinements to the application of static ratings, followed by a more widespread development of dynamic line ratings, which will be supported by improvements to the infrastructure (including weather stations) that is needed to apply and validate the dynamic line ratings. The Strategy also includes the development of software modules to support analysis and quantification of risk and data management.

The investment required to implement our Plant and Line Rating Strategy is proposed to form part of our 2023-24 to 2027-28 NCIPAP (EC.15571, section 7.6).

ElectraNet continually reviews the conditions of its network assets to ensure that these assets are suitable to support the forecast load. Where condition assessment indicate that an asset's condition is declining to an unacceptable level, a planned refurbishment or replacement program is put in place.

ElectraNet currently has no plans to de-rate any of its assets.

7.9 Grouped network asset retirements, de-ratings and replacements

Various programs of work that exceed $6 million for grouped network asset retirement and replacement are proposed over the 10-year planning period (table below).

Further details, including for projects that do not exceed the RIT-T cost threshold, are available from our Transmission Annual Planning Report web page.[43]

We do not envisage that any of these projects will have impact inter-network transfer.

Grouped projects committed, planned and proposed to meet asset retirement and replacement needs

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14047 Transformer bushing unit asset replacement 2018-19 to 202223 Estimated cost: **$6-8 million** Status: **Committed** Replace 101 individual transformer bushings that have been assessed to be at the end of their technical or economic lives on 18 transformers across 10 substation sites. This project includes the replacement of assets at the following sites: Berri, Cherry Gardens, LeFevre, Murray Bridge–Hahndorf No. 1 Pump Station, Murray Bridge–Hahndorf No. 3 Pump Station, North West Bend, Para, Robertstown, Yadnarie We published a PACR on 11 December 2018, concluding the RIT-T for this program of work.[44]	Various	Asset condition and performance Asset renewal	October 2022
EC.14032 Instrument Transformer unit asset replacement 201819 to 2022-23 Estimated cost: **$10-14 million** Status: **Committed** Replace 55 voltage transformers and 121 current transformers across the South Australian electricity transmission system that have reached the end of their technical or economic lives and have an increased likelihood of catastrophic explosion. This project includes the replacement of assets at the following sites: Angas Creek, Berri, Brinkworth, Davenport, East Terrace, Happy Valley, Hummocks, Kanmantoo, Keith, Kilburn, Kincraig, Leigh Creek South, Morphett Vale East, Murray Bridge/Hahndorf No.1 Pump Station, North West Bend, Northfield, Parafield Gardens West, Port Lincoln Terminal, Robertstown, Snuggery, South East, Stony Point, Tailem Bend, Templers, Yadnarie We published a PACR on 7 January 2020, concluding the RIT-T for this program of work.[45]	Various	Asset condition and performance Asset renewal	June 2023
EC.14034 Isolator unit asset replacement 2018-19 to 2022-23 Estimated cost: **$8-12 million** Status: **Committed** Replace individual substation isolators that have been assessed to be at the end of their technical or economic lives or that no longer have manufacturer support, at 16 sites across South Australia where the asset won't be replaced as part of an augmentation or substation rebuild during the 2018-19 to 2022-23 regulatory period. This project includes the replacement of assets at the following sites: Berri, Cultana, Dorrien, LeFevre, Magill, Middleback, Monash, Mount Gambier, Para, Penola West, Robertstown, Snuggery, Tailem Bend, Torrens Island A, Torrens Island B We published a PACR on 18 November 2019, concluding the RIT-T for this program of work.[46]	Various	Asset condition and performance Asset renewal	September 2024
EC.14031 Protection systems unit asset replacement 2018-19 to 2022-23 Estimated cost: **$25-35 million** Status: **Committed** Replace protection scheme relays across the South Australian electricity transmission system that have reached the end of their technical or economic lives. This project includes the replacement of assets at the following sites: Angas Creek, Berri, Brinkworth, Davenport, East Terrace, Happy Valley, Hummocks, Kanmantoo, Keith, Kilburn, Kincraig, Leigh Creek South, Morphett Vale East, Murray Bridge/Hahndorf No.1 Pump Station, North West Bend, Northfield, Parafield Gardens West, Pimba, Port Lincoln Terminal, Robertstown, Snuggery, South East, Stony Point, Tailem Bend, Templers, Yadnarie We published a PACR on 6 December 2019, concluding the RIT-T for this program of work.[47]	Various	Asset condition and performance Asset renewal	September 2024
EC.15242 Transformer bushing unit asset replacement 2023-24 to 2027-28 Estimated cost: **$5-10 million** Status: **Proposed** Replace individual transformer bushings on 15 high voltage transformers at 13 substations across the South Australian electricity transmission system that have been assessed to be at end-of-life during the 2023-24 to 2027-28 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2024 –2028
EC.15120 Instrument Transformer unit asset replacement 2023-24 to 2027-28 Estimated cost: **$15-25 million** Status: **Proposed** Replace 25 voltage transformers and 93 current transformers at 14 substations across the South Australian electricity transmission system that have been assessed to be end-of-life during the 2023-24 to 2027-28 regulatory control period to address the increased risk of unsafe operation and poor performance. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2024 –2028
EC.15189 Protection relay unit asset replacement 2023-24 to 2027-28 Estimated cost: **$6-12 million** Status: **Planned** Replace protection relays and associated components at five substations across the South Australian electricity transmission system that have been assessed to be end-of-life during the 2023-24 to 2027-28 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2024 –2028
EC.15397 Isolator unit asset replacement Estimated cost: **$25-45 million** Status: **Proposed** Replace 74 individual substation isolators at 12 substations across the South Australian electricity transmission system that have been assessed to be at end-of-life during the 2023-24 to 2027-28 regulatory control period. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2024 –2028

[43] *Our Transmission Annual Planning Report web page is available at https://www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/*
[44] *The Managing the Risk of Transformer Bushing Failure PACR is available from www.electranet.com.au/ projects/transformer-bushing-replacements/.*
[45] *The Managing the Risk of Instrument Transformer Failure PACR is available from https://www.electranet.com.au/projects/managing-the-risk-of-instrument-transformer-failure-project/.*
[46] *The Managing the Risk of Isolator Failure PACR is available from https://www.electranet.com.au/projects/isolator-replacement-and-refurbishment-project/.*
[47] *The Managing the Risk of Protection Relay Failure PACR is available from https://www.electranet.com.au/projects/managing-the-risk-of-protection-relay-failure/.*

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15123 Instrument Transformer unit asset replacement 2028-29 to 2032-33 Estimated cost: **$50-80 million** Status: **Proposed** Replace voltage transformers and current transformers across the South Australian electricity transmission system that have reached the end of their technical or economic lives and have an increased likelihood of catastrophic explosion. This project will include the replacement of assets which will be determined based on asset needs. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029 – 2033
EC.15244 Transformer bushing unit asset replacement 2028-29 to 2032-33 Estimated cost: **$5-10 million** Status: **Proposed** Replace individual transformer bushings that will be assessed to be at the end of their technical or economic lives during the 2028-29 to 2032-33 regulatory control period. This project will include the replacement of assets which will be determined based on asset needs. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029 – 2033
EC.15211 Protection relays unit asset replacement 2028-29 to 2032-33 Estimated cost: **$8-15 million** Status: **Proposed** Replace protection relays and control schemes across the South Australian electricity transmission system that have reached the end of their technical or economic lives. This project will include the replacement of assets which will be determined based on asset needs. We plan to initiate a RIT-T prior to commitment.	Various	Asset condition and performance Asset renewal	2029 – 2033

7.10 Security and compliance projects

There are a range of committed and planned projects that relate to the maintenance of our security and compliance for which planned expenditure exceeds $6 million (table below).

Further details, including for projects with a cost less than $6 million, are available from our Transmission Annual Planning Report web page.[48]

Projects planned to address market benefit opportunities

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14131 Motorised Isolator LOPA Improvement Cost: **$10 –12 million** Status: **Committed** Modify 876 isolators and replace 33 isolators to provide satisfactory mechanical and electrical isolation lock-off points on all motorised air insulated isolators identified as safety hazards by a Layer of Protection Analysis (LOPA).	Various	Safety Asset renewal	June 2022
EC.11828 Substation perimeter intrusion and motion detection security system Estimated cost: **$12-20 million** Status: **Proposed** Upgrade substation security systems across all ElectraNet substations by installing external motion detection and CCTV systems with built-in analytics reporting back to a networked video management system. These external motion detection and CCTV systems will supplement the "deter and delay" primary control measures such as fences and signage with a proactive and responsive secondary system, responding to potential unauthorised presence inside the security fence.	Various	Safety Operational	2024 – 2028
EC.15235 Transmission line anti-climb installation 2023-24 to 2027-28 Estimated cost: **$25-50 million** Status: **Proposed** Install climbing deterrent devices and warning signage on 3,410 transmission towers located on 61 high voltage transmission lines that have been assessed as highly vulnerable to unauthorised access.	Various	Safety Asset renewal	2024 – 2028
EC.15401 Happy Valley site drainage replacement Estimated cost: **$5-10 million** Status: **Proposed** Replace the existing drainage system at Happy Valley substation with a new drainage system to improve site drainage, stability of footings, and trafficability on site roadways and reduce erosion issues.	Metropolitan	-	2024 – 2028
EC.15231 – Transmission line anti-climb 2028-29 to 2032-33 Estimated cost: **$25-50 million** Status: **Proposed** Replace or install climbing deterrent devices and warning signage on all identified line tower assets to meet and maintain requirements to prevent unauthorised access to electricity infrastructure.	Various	Safety Asset renewal	2029 – 2033

[48] Our Transmission Annual Planning Report web page is available at https://www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/

Appendices

Appendix A: Summary of changes since the 2020 Transmission Annual Planning Report

In this appendix we provide an analysis and explanation of any aspects of forecast loads, and other aspects of the 2021 Transmission Annual Planning Report (TAPR) that have changed significantly from the 2020 report. The following table includes a summary of the significant changes to our Transmission Annual Planning Report, which may be due to:

- changes to input datasets, assumptions or methodologies
- actual outcomes or future forecasts being different from the previously reported forecasts
- additional information being included to meet new Rule requirements.

Section	Section Name	Significant changes between the 2020 and 2021 TAPR	Analysis and explanation for the significant change
1.1	South Australia's electricity system is breaking new ground	Figure 1.1 has been updated based on the latest available figures Section 1.1 now includes a description of the emerging challenges introduced by the continuing adoption of rooftop solar generation	The changes to section 1.1 help to indicate the magnitude of the change that is forecast in South Australia's electricity system over the coming decade and the consequential emerging challenges
1.1.1	Implications of the power system transition	This is a new section in 2021	This section has been added to describe the increasing role that ElectraNet has to play in addressing the emerging challenges to the power system
1.2	Network Vision, future directions and key priorities	This section has been extended in 2021, and contains additional details regarding the key themes, future directions and key priorities that are described in our Network Vision	Our Network Vision was refreshed earlier in 2021 This section describes how our strategic initiatives and investigations link to our Network Vision
1.3	How are our key priorities helping us prepare for the future?	This section has been retitled The information in this section has been updated	We have updated the information in this section to reflect our current areas of focus
2.1.1	System strength	The information in this section has been updated	We have updated the information in this section to reflect the completed installation of synchronous condensers at Davenport and Robertstown
2.1.2	Project EnergyConnect	The information in this section has been updated	We have updated the information in this section to reflect the progress of Project EnergyConnect
2.1.4	Mid North expansion to release REZ capacity in the north of South Australia	This section has been retitled The information in this section has been streamlined	The updated title better reflects the content of this section
2.2.1	Recommendations for South Australia	The information in this section has been updated	The expanded information in this section reflects the outcomes of AEMO's Stage 2 2021 PSFRR, published in December 2020
2.3	General Power System Risk Review	This is a new section in 2021	We have added this section to reflect the new Rules requirement for implementation of a GSPRR by 31 July 2023
3.1	South Australian electricity demand	Figure 3.1 has been updated to include data for 2020-21	This update figure reflects the latest available information
3.3	Demand forecasts	Figure 3.2 has been updated to include data from AEMO's 2021 ESOO	This update figure reflects the latest available information
3.3.1	Potential key drivers of demand	This is a new section in 2021	We have added this section to describe potential drivers that could in future increase demand levels higher than the current forecasts
N/A	Impact of COVID-19 pandemic on forecasts	This section has been removed	We did not consider it necessary to include this section in 2021
3.4	Performance of 2020 demand forecast	This section has been retitled	We have updated the information in this section to include a review of minimum demand forecasts

Section	Section Name	Significant changes between the 2020 and 2021 TAPR	Analysis and explanation for the significant change
3.4.1	Weather conditions during summer	This section has been retitled The information in this section has been updated	We have updated this section to reflect the latest available information
3.4.2	State-wide demand review	The information in this section has been updated and extended	We have updated this section to reflect the latest available information We have extended this section to also include a summary of very low demands that were recorded between 1 October 2020 and 30 September 2021
3.4.3	Connection point maximum demand review	The information in this section has been updated	We have updated this section to reflect the latest available information
4.2	Transmission system constraints in 2020	The information in this section has been updated	We have updated this section to reflect the latest available information We have selected constraints for analysis if their impact exceeded $50,000 during 2020
4.3	Emerging and future network constraints and performance limitations	The information in this section has been updated	We have updated this section to reflect forecast binding constraints and hours based on the 2020 ISP Step Change scenario
4.4	Potential projects to address future constraints	The information in Table 4.3 has been substantially updated	We have simplified the information in this table and only included projects that are not yet proposed for inclusion in our capital plan or in our proposed 2023-24 to 2027-28 NCIPAP
4.5.1	Automatic under-frequency generator shedding	The information in this section has been updated	We have updated this section based on the findings of AEMO's Stage 2 2021 PSFRR, published in December 2020
5	Connection opportunities and demand management	The information in this section has been updated	We have updated this section based on AEMO's 2021 ESOO
5.1	New connections and withdrawals	This is a new section in 2021	We have added this section to provide information on supply-side changes in the last year
5.3	Connection opportunities for generators	The information in this section has been updated	As was done in years prior to 2020, we have conducted a high-level assessment of the ability of existing transmission nodes and connection points to accommodate new generator connections
5.3.1	Approach to generation connection opportunity calculations	This section was not included in 2020	We have again included this section to describe our approach to the assessment we have performed
5.3.4	Opportunities to connect to Project EnergyConnect	This section is new in 2021	We have added this section to provide high-level information to proponents who are keen to take advantage of the increased interconnection that will be introduced by Project EnergyConnect
5.4	Connection opportunities for customers	The information in this section has been updated	As was done in years prior to 2020, we have conducted a high-level assessment of the ability of existing transmission nodes and connection points to accommodate new load connections
5.5	Summary of connection opportunities	This section was not included in 2020	We have again included this section to provide a summary of the outcomes of our assessment
5.6	Proposed and committed new connection points	The table has been removed from this section	There are currently no proposed or committed new connection points
5.7	Projects for which network support solutions are being sought or considered	The table in this section is significantly shorter than it was in 2020	There are currently only two projects that either have completed their consultation process within the last 12 months, or are expected to commence consultation within the next 12 months – this is a greatly reduced number compared to the many projects that had completed consultation between publication of the 2019 and 2020 reports
6.1	Recently completed projects	The following projects have been completed in the last 12 months: • EC.14207 System Integrity Protection Scheme (SIPS) • EC.14219 Main Grid system strength support • EC.14168 NCIPAP Smart Wires Power Guardian Technology Trial	We have updated the information to reflect the status of projects completed up until 30 October 2021 Many of these projects were listed as committed projects in 2020
6.2	Committed projects	The following projects have become committed in the last 12 months: • EC.14245 Port Pirie and Bungama 11kV RMU and Aux Transformer Replacement • EC.14132 Isolator Status Indication • EC.15307 Para Emergency SVC Transformer Replacement • EC.14246 Wide Area Protection Scheme (WAPS) • EC.14211 South East 275 kV Capacitor Bank • EC.14171 Project EnergyConnect: South Australia to New South Wales interconnector • EC.14046 AC Board Replacement 2018 - 2023	These projects were proposed in the 2020 report, but are now committed to address market benefit, safety, asset condition and performance, reliability, and security drivers
6.3	Pending Projects	The table of pending projects has been removed	We currently have no pending projects
7	Transmission system development plan	Table 7.1 and Figure 7.1 have been updated	This information has been updated based on our latest information relating to generalised credible generator and load connections that could materially impact the performance of the transmission system
7.1	Summary of planning outcomes	Table 7.2 has been updated	We have updated this information to reflect the latest results of our ongoing planning processes
7.3	Interconnector and Smart Grid planning	EC.14207 System Integrity Protection Scheme (SIPS) has been completed and is now listed in table 6.1 The planned asset in service date of EC.14246 Wide Area Protection Scheme (WAPS) has been delayed by one month The cost and asset in service dates of EC.14171 Project EnergyConnect have been updated, and the project is now committed Additional detail has been added for EC.15272 Wide Area Monitoring Scheme 2023-2028 EC.15241 Wide Area Protection Scheme expansion 2023-24 to 2027-28 is no longer proposed EC.15112 Heywood Interconnector dynamic voltage stability increase has been incorporated with the potential scope of EC.15149 in section 7.4	We have updated this information to reflect the latest results of our ongoing project and planning processes

Section	Section Name	Significant changes between the 2020 and 2021 TAPR	Analysis and explanation for the significant change
7.4	System security, power quality and fault levels	EC.14219 Main Grid system strength support has been completed and is now listed in table 6.1 EC.15297 Maintain adequate suppression of grid harmonic voltage distortion and ongoing management of voltage fluctuation and unbalance levels has been renamed as Power Quality Monitoring, with a reduced scope and cost which puts it below the cost threshold for inclusion in our TAPR document ($6 million for projects of this type) EC.15572 Network Power Quality Remediation is a newly proposed contingent project to address any remediation needs identified by EC.15297 The name of EC.11645 Transmission Network Voltage Control has been updated and its scope has been expanded to include the installation of a suite of 275 kV reactors Project EC.15441 Maintain local voltage control at times of low demand is no longer proposed	We have updated this information to reflect the latest results of our ongoing project and planning processes
7.5	Capacity and Renewable Energy Zone Development	The expected cost for EC.14172 Eyre Peninsula Link has been updated Project EC.15104 Eyre Peninsula upgrade now includes as an option the scope that was previously being considered in project EC.15261 Build new third and fourth circuits between Davenport and Cultana Project EC.14085 Establish new connection point at Gawler East is no longer proposed The anticipated timing has been updated for EC.11011 Upper South East network augmentation Project EC.15201 Riverland REZ Hub Connection is no longer being considered for proposal as a contingent project Project EC.15205 Increase transfer capacity between Robertstown, Davenport and Adelaide now includes as options the scope that was previously proposed or being considered in project EC.15209 Second Templers West transformer and reconfigure Mid North 132 kV network and in project EC.15153 Increase transfer capacity between Davenport and Adelaide	We have updated this information to reflect the latest results of our ongoing project and planning processes
7.6	Market benefit opportunities	EC.14168 Trial modular power flow elements to relieve congestion has been completed and is now listed in table 6.1 The timing of EC.14211 South East 275 kV capacitor bank has been updated Project EC.11022 Strengthen the Eastern Hills transmission corridor has been retained in our 2018-19 to 2022-23 NCIPAP, and not deferred as had been indicated in 2020 The following projects are proposed for our 2023-24 to 2027-28 NCIPAP: • EC.15179 Uprate Robertstown – Tungkillo 275 kV lines • EC.15171 Uprate Davenport – Cultana 275 kV lines • EC.15175 Increase Murraylink transfer capacity • EC.15175 10-band rating NCIPAP project • EC.15182 Munno Para control scheme	We have updated this information to reflect the latest results of our ongoing project and planning processes
7.7	Network asset retirements and replacements	The expected completion date has been delayed for EC.14049 Leigh Creek South transformer replacement EC.11749 AC Board replacement 2013 – 2018 has been completed and is now listed in table 6.1 The expected completion date has been delayed for EC.14046 AC Board Replacement 2018-19 to 2022-23 The expected completion date has been advanced for EC.14084 Line Conductor and Earthwire Refurbishment 2018-19 to 2022-23 Program EC.14090 Mount Gambier transformer 1 replacement has been deferred to the 2028-29 to 2032-33 period, as minor refurbishment works are being undertaken in this period to extend its service life We have revised the cost ranges of the following projects: • EC.15060 Circuit breakers unit asset replacement 2023-24 to 2027-28 • EC.15043 AC Board unit asset replacement 2023-24 to 2027-28 • EC.15233 Transmission line insulation system refurbishment 2023-24 to 2027-28 • EC.15239 F1803 Hummocks – Ardrossan West 132 kV Line Refurbishment EC.15116 Hummocks substation replacement is no longer proposed The proposed timing of EC.15432 F1802 Bungama – Pt Pirie 132 kV Line Refurbishment has been deferred to the 2028-29 to 2032-33 period We have revised the scope of EC.15432 Transmission line refurbishment 2023-24 to 2027-28 Check if need to make any note about EC.15168 Mount Gambier substation replacement	We have updated this information to reflect the latest results of our ongoing project and planning processes
7.9	Grouped network asset retirements, de-ratings and replacements	We have revised the anticipated timing of EC.14047 Transformer bushing asset replacement 2018-19 to 2022-23 We have refined the scope and/or revised the anticipated cost ranges of the following projects: • EC.15120 Instrument Transformer unit asset replacement 2023-24 to 2027-28 • EC.15189 Protection relay unit asset replacement 2023-24 to 2027-28 • EC.15397 Isolator unit asset replacement The following projects are no longer proposed: • EC.15275 Earth leakage protection replacement 2023-24 to 2027-28 • EC.15214 Protection signal equipment replacement stage 1 2028-29 to 2032-33	We have updated this information to reflect the latest results of our ongoing project and planning processes
7.10	Security and compliance projects	We have revised the anticipated timing of EC.14131 Motorised Isolator LOPA Improvement We have refined the scope of the following projects: • EC.11828 Substation perimeter intrusion and motion detection security system • EC.15235 Transmission line anti-climb installation 2023-24 to 2027-28 Project EC.15401 Happy Valley site drainage replacement is newly proposed	We have updated this information to reflect the latest results of our ongoing project and planning processes
Appendix E	Contingent projects	We have updated this section to include the current status of each contingent project in our 2018-19 to 2022-23 regulatory control period, and added a summary of contingent projects that we are considering to propose for the 2023-24 to 2027-28 revenue control period	This information has been included to enable stakeholders to understand the status of each contingent project and the range of contingent projects currently being considered

Appendix B: Joint Planning

ElectraNet undertakes a wide range of joint planning activities with both transmission and distribution entities on a regular and as-needed basis, and through a range of forums.

ElectraNet works closely with SA Power Networks to ensure optimal solutions for South Australian customers are identified and implemented.

Joint planning activities also include significant engagement with AEMO (as both national planner and Victorian transmission planner), TransGrid, APA (owner of Murraylink interconnector), AusNet Services, Powerlink, and major customers.

Our joint planning activities over the last year are described more fully in the following sections.

B1 National transmission planning working groups and regular engagement

ElectraNet has collaborated with the other NEM jurisdictional planners through active involvement in the following groups:

- Executive Joint Planning Committee
- Joint Planning Committee
- Regulatory Working Group
- Market Modelling Reference Group
- Forecasting Reference Group
- Regular joint planning meetings
- Power System Modelling Reference Group
- ENA.[49]

B1.1 Executive Joint Planning Committee

The Executive Joint Planning Committee facilitates effective collaboration and consultation between Jurisdictional Planning Bodies and AEMO on electricity transmission network planning issues to:

- collaborate on development of the Integrated System Plan
- improve network planning practices
- coordinate on energy security across the NEM.

The Executive Joint Planning Committee directs and coordinates the activities of the Joint Planning Committee, the Regulatory Working Group, and the Market Modelling Working Group.

B1.2 Joint Planning Committee

The Joint Planning Committee supports the Executive Joint Planning Committee to achieve effective collaboration, consultation and coordination between Jurisdictional Planning Bodies, Transmission System Operators and AEMO on electricity transmission network planning issues.

B1.3 Regulatory Working Group

The Regulatory Working Group supports the Executive Joint Planning Committee to achieve effective collaboration, consultation and coordination between Jurisdictional Planning Bodies, Transmission System Operators and AEMO on key areas related to the application of the regulatory transmission framework and suggestions for improvement.

B1.4 Market Modelling Working Group

The Market Modelling Working Group supports the Executive Joint Planning Committee in effective collaboration, consultation and coordination between Jurisdictional Planning Bodies, Transmission System Operators and AEMO. The committee focuses on modelling techniques, technical knowledge, industry experience, and a broad spectrum of perspectives on market modelling challenges.

B1.5 Forecasting Reference Group

The Forecasting Reference Group is a monthly forum with AEMO and industry's forecasting specialists. The forum seeks to facilitate constructive discussion on matters relating to gas and electricity forecasting and market modelling. It is an opportunity to share expertise and explore new approaches to addressing the challenges of forecasting in a rapidly changing energy industry.

[49] See www.energynetworks.com.au.

B1.6 Joint planning meetings

For effective network planning, ElectraNet conducts joint planning activities with:

- SA Power Networks, the South Australian Distribution Network Service Provider (DNSP)
- AEMO (in their roles as National Planner and Jurisdictional Planning Body for the Victorian transmission system)
- TransGrid.

ElectraNet has a long-standing relationship with South Australia's electricity distribution business, SA Power Networks. We collaborate through joint planning on things like annual demand forecast updates, network development options and voltage control strategies.

ElectraNet and SA Power Networks have taken steps to strengthen collaboration on these matters, including the establishment of an Executive level forum to facilitate consideration of alignment on key changes impacting on the network.

ElectraNet and SA Power Networks also meet regularly with AEMO and the SA Government to coordinate key policy, planning and other developments impacting on ensuring successful energy transformation in South Australia.

Joint planning interactions between ElectraNet and SA Power Networks

Executive Oversight	Joint Planning - ElectraNet and SA Power Networks
SA Network Policy and Strategy Committee – ElectraNet and SA Power Networks. **Purpose:** Ensure alignment of long-term vision and strategies, and oversee coordination of joint planning.	**Routine Joint Planning Activities** **Purpose:** Deliver lowest long run costs by identifying efficient network solutions across both transmission and distribution, as well as support the distributed energy future efficiently.
SA Energy Transition Steering Group – AEMO, SA Government, SA Power Networks and ElectraNet. **Purpose:** Ensure the reliability and security of the SA electricity system is effectively managed through the energy transition.	**Voltage Control Working Group** **Purpose:** Develop joint voltage management strategies and plans to ensure the networks support the distributed energy future efficiently

B1.7 Power System Modelling Reference Group

The Power System Modelling Reference Group is a quarterly forum with AEMO and industry power system modelling specialists. The forum seeks to focus on power system modelling and model development to ensure an accurate power system model is maintained for power system planning and operational studies.

B2 Joint Planning Projects

ElectraNet has coordinated with other jurisdictional planners on the following projects:

- Integrated System Plan development (section 2.1)
- Project EnergyConnect (sections 1.3.1, 2.1.2, 6.2 and 7.3).

Appendix C: Asset management approach

C1 ElectraNet's Asset Management Strategy

Our Asset Management Objectives are:

- Safety of people – ensure the safety of staff, contractors and the public;
- Protect the environment – ensure the environmental impact of network operations are minimised;
- Affordability and reliability – reduce the overall cost of electricity to customers by removing network constraints, operating the network and delivering our capital and maintenance works as efficiently as possible, while maintaining safety and reliability;
- Power system security and resilience – ensure the network is resilient and operates within acceptable parameters in the face of electrical, physical, or cyber disruption, and continues to enable the transition to a low carbon emissions future.

These objectives guide our asset management plans and activities.

The Asset Management Objectives were developed in consultation with ElectraNet's Consumer Advisory Panel and are consistent with the National Electricity Objective and the capital expenditure objectives set out in the Rules[50].

Most of our investment program in the planning period relates to risk-based asset replacement and line refurbishment and targeted network security measures, with the remainder relating to recurrent and other capital expenditure required to maintain the systems and facilities needed to efficiently run the network.

Our asset management strategic planning framework is designed to deliver a safe and reliable network at an efficient cost. The table below summarises how we ensure that our capital expenditure forecasts are efficient and prudent. Further detailed information is provided in the later sections of this appendix.

Inputs and Analysis	Our Approach
Demand forecasts and reliability	Forecast demand is an important driver of reliability capital expenditure. We use estimates of the Value of Customer Reliability (VCR) as determined by the AER.[51] Adopting these independent values provides confidence in these inputs. The demand forecasts are compared against the ability of the transmission system to meet the reliability standard set by the ETC and the Rules.
Project cost estimates and efficiencies	An efficient capital expenditure forecast relies on accurate project cost estimates. To ensure that our project cost estimates are accurate, we update our estimates for the latest actual project costs and market rates. We also incorporate efficiencies expected to arise as we combine the delivery of related projects. We obtain check estimates of project costs from independent experts to verify the efficiency and prudency of our estimates. This ensures our project cost estimates are accurate and reasonable.
Economic assessments	We conduct economic assessments to determine whether the benefits of undertaking a project exceed its costs and we review all available options. We examine the optimal timing of each project, so that customers obtain the maximum net benefit from the expenditure and projects are deferred when this is more economic. The RIT-T is applied for all relevant projects that have a credible option with a cost that exceeds the threshold set in the Rules.
Risk and reliability analysis	Any decision to replace an asset is driven by asset condition, risk and reliability considerations balanced against cost. Our risk analysis considers the: • probability of an asset failure • likelihood of adverse consequence(s) • likely cost(s) of the consequence(s). This is based on a systematic process for collecting, recording and analysing detailed information on the condition of network assets, and balances the expected risk reduction against the costs of the proposed expenditure to ensure safety and reliability requirements are met at lowest cost. The risk cost reduction and other benefits of a proposed asset replacement are compared to the cost of the replacement project to determine whether the proposed expenditure delivers a net market benefit.

C2 Obligations relating to capital expenditure

[50] NER clauses 6.5.6(a), 6.5.7(a), 6A.6.6 and 6A.6.7.

[51] AER, Values of customer reliability final decision, available from https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/final-decision.

In developing our capital expenditure plans we are guided by the requirements of:

- our transmission licence and the Electricity Transmission Code (ETC)
- the National Electricity Rules
- our Safety, Reliability, Maintenance and Technical Management Plan (SRMTMP), which is required by our transmission licence.

C2.1 Transmission licence and ETC obligations

Under section 15 of the Electricity Act 1996 (SA), we are required to be licensed to operate a transmission network in South Australia. The transmission licence authorises us to operate the transmission network in accordance with the terms and conditions of the licence.

Our transmission licence sets out obligations in relation to network performance, which have implications for our capital expenditure requirements. These obligations require us to:

- maintain connection point reliability standards
- maintain regulated voltage levels and reactive margins
- manage fault levels
- manage equipment ratings
- manage system stability and security
- manage quality of supply (frequency, harmonics and flicker).

The transmission licence is issued by ESCOSA.[52]

A central part of ESCOSA's licensing function is to set standards of service under the terms of each licence. ESCOSA undertakes this task through the provisions of the ETC, made pursuant to Part 4 of the Essential Services Commission Act 2002 (ESC Act). Compliance with the ETC is a mandatory licence condition for ElectraNet as well as a regulatory obligation in accordance with clause 6A.6.7 of the Rules.

Section 1.6.1 of the ETC makes it clear that any obligations imposed under the ETC are in addition to those imposed under the Rules and the Electricity Act 1996 (SA) (and regulations). We must therefore comply with both the ETC and the Rules.

The ETC forms part of a broader regulatory scheme for transmission in the NEM, with regulation of the system occurring at two levels:

- the Rules establish technical standards dealing with matters such as frequency, system stability, voltage and fault clearance[53]
- jurisdictional standards, such as those set out under the ETC, provide for security and reliability standards which align with technical standards set out under the Rules.

In particular, the ETC contains provisions relating to service standards, interruptions, design requirements, technical requirements, general requirements, access to sites, telecommunications access and emergencies.

Clause 2 of the ETC mandates specific reliability standards at each transmission exit point (a customer connection point) or group of exit points and supply restoration standards. These are summarised in the table overleaf.[54]

[52] Our transmission licence as currently in force (last varied 16 October 2019) is available at https://www.escosa.sa.gov.au/industry/electricity/licensing/licence-register/exemption-register.

[53] National Electricity Rules, Schedule 5.1

[54] The full version of the ETC version TC/09.4 is available at escosa.sa.gov.au.

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
Transmission line capacity					
'N' capacity	100% of agreed maximum demand (AMD)				
'N-1' capacity	Nil		100% of AMD		
'N-1' continuous capability	Nil			100% of AMD for loss of single transmission line or network support arrangement	
Restoration time to 'N' standard after outage (as soon as practicable – best endeavours*)	2 days		1 hour	12 hours (or 4 hours if grouped with category 5 connection point)	4 hours for 176 MW
Restoration time to 'N-1' standard after outage	N/A		As soon as practicable – best endeavours		
Transformer capacity					
'N' capacity	100% of AMD				
'N-1' capacity	Nil	100% of AMD			
'N-1' continuous capability	None stated	100% of AMD for loss of single transformer or network support arrangement	Nil	100% of AMD for loss of single transformer or network support arrangement	
Restoration time to 'N' standard after outage (as soon as practicable – best endeavours*)	8 days		1 hour	12 hours (or 4 hours if grouped with category 5 connection point)	4 hours for 176 MW
Restoration time to 'N-1' standard after outage	N/A	As soon as practicable – best endeavours			
Spare transformer requirement	Sufficient spares of each type to meet standards in the event of a failure				
Allowed period to comply with required contingency standard following a change in forecast AMD that causes the specific reliability standard to be breached	N/A	12 months			

** As defined in the ETC*

ESCOSA made minor amendments to the ETC in June 2021. [55]

Note that 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 interruptibility, or any combination of these services.

[55] The final decision is available at https://www.escosa.sa.gov.au/ArticleDocuments/21717/20210624-Electricity-TransmissionCodeReview-FinalDecision.pdf.aspx?Embed=Y.

C2.2 Rules requirements

ElectraNet is the principal TNSP and the Jurisdictional Planning Body for South Australia under clause 11.28.2 of the Rules. As such, we have specific obligations under Chapter 5 of the Rules regarding network connection, network planning and establishing or modifying a connection point, including technical obligations that apply to all registered participants.

As part of our planning and development responsibilities, we 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 DNSPs and other TNSPs whose networks can impact the South Australian transmission network
- 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.

The planning process considers network and non-network options, such as local generation and demand side management initiatives, on an equal footing. We select the solution (which may include 'do nothing') that maximises net benefits.

C2.3 Safety, Reliability, Maintenance and Technical Management Plan

In accordance with clause 7 of our transmission licence, we are required to:

- prepare and submit to ESCOSA for approval a SRMTMP dealing with the matters prescribed by regulation
- annually review, and if necessary update, the plan to ensure its efficient operation, and submit the updated plan to ESCOSA for approval
- not amend the plan without the approval of ESCOSA
- comply with the plan (as updated from time to time) as approved by ESCOSA
- undertake annual audits of our compliance with our obligations under the plan and report the results of those audits to the Office of the Technical Regulator (OTR), in a manner approved by the OTR.

The SRMTMP must address, amongst other things, the safe design, installation, commissioning, operation, maintenance and decommissioning of electricity infrastructure owned or operated by a licensed person. As such, the SRMTMP, in addition to the obligations described in Sections 6.5.1 and 6.5.2, is an important driver of our future capital expenditure requirements.

C3 Capital expenditure categories

We apply a range of categories to our capital expenditure. The table below describes the expenditure categories that are relevant to Transmission Annual Planning Reports. For each category, we also identify the AER's reporting category as indicated in their TAPR Guideline.[56]

ElectraNet Expenditure Category	Definition	Service Category	AER's TAPR Guidelines project driver
Network – Load or Market Benefit Driven			
Augmentation	Works to enlarge the system or to increase its capacity to transmit electricity. This includes projects to which the RIT-T applies and involves the construction of new transmission lines or substations, reinforcement or extension of the existing shared network. The projects may be driven by reliability or market benefits requirements, and are inclusive of any supporting communications infrastructure, land and IT systems.	Transmission Use of System Services (TUOS)	Capacity, reliability, market benefit, stability or reactive support
Connection	Works to either establish new prescribed customer connections or to increase the capacity of existing prescribed customer connections based on specific customer requirements. Includes projects driven by the Electricity Transmission Code (ETC) reliability standards. In accordance with the Rules, new connection works between regulated networks are treated as prescribed services. Other new connections are treated as negotiated or contestable transmission services.	Exit Services	Capacity
Network Non-Load and Non-Market Benefit Driven			
Replacement	Nil Works to replace transmission lines, substation primary plant, secondary systems, communications equipment and other transmission system assets in order to maintain reliability of supply. Replacement projects are generally undertaken due to the increased risk of plant failure as a result of asset age, asset condition, obsolescence or safety issues.	Exit Services and TUOS	Asset condition and performance
Refurbishment	For some assets, refurbishment is an alternative to asset replacement. Refurbishment works are generally undertaken based on the asset condition, performance and asset risk to efficiently extend asset life as a more economical alternative to wholesale asset replacement.	TUOS	Asset condition and performance
Security /Compliance	Projects that address network compliance requirements set out in legislation and regulations, and industry standards. Projects required to ensure the physical and system security of critical infrastructure assets.	Entry Services, Exit Services, TUOS, Common Services	Power quality, operational, compliance, environmental or safety

[60] *Consultation paper available from www.aer.gov.au.*

C4 Expenditure forecasting methodology

Our capital expenditure forecasting methodology is outlined below.

C4.1 Customer and stakeholder requirements

The starting point for our capital expenditure forecasting methodology is understanding our customers' requirements through effective engagement. Our expenditure priorities are shaped by the feedback we have received through our customer engagement process.

C4.2 Planning process

The planning process operates within a strategic framework informed by our Network Vision , and industry planning documents prepared by AEMO such as the Integrated System Plan (ISP). The planning process also relies on inputs such as demand forecasts and connection applications.

C4.3 Assessment of network limitations

In developing our forecast capital expenditure, we consider projected network limitations, the condition and performance of the existing assets and the associated supporting facilities and business systems required to efficiently operate the network over the forecast period. The application of this approach differs by expenditure category:

- Load and market benefit driven network investment requirements are identified through modelling of future power system capability and analysis of network constraints
- Non-load and non-market benefit driven network investment requirements are determined in accordance with our asset management framework, which takes a risk-based approach to the replacement or refurbishment of assets based on assessed risk, condition and performance.

C4.4 Options analysis

A range of solutions (including both network and non-network options) are considered to address identified network limitations, and to efficiently defer the need for major capital investments for as long as possible, while maintaining safety, security, reliability and resilience, following a risk-based approach.

Economic analysis and risk assessment techniques are applied to investigate the potential options. The preferred solution must be technically and economically feasible, be deliverable in the timeframe required and minimise long-run total costs.

C4.5 Scope and estimate

All network solutions are designed to meet the identified need while complying with legislated safety, environmental and technical obligations.

Project cost estimates are developed for each solution based on a detailed database of materials and transmission construction costs, and recent outturn cost information from delivered projects.

Approved projects that are currently in progress have been subject to a more detailed cost assessment than those which have yet to commence.

For non-network projects, cost estimates are generally developed based on independent expert advice and market cost information.

[61] *Available from www.electranet.com.au.*

C5 Key inputs and assumptions

This appendix describes the key inputs and assumptions underlying the network expenditure forecast and provides substantiation for these inputs and assumptions, which comprise:

- demand forecasts
- asset health and condition assessments
- planning and design standards
- network modelling
- economic assessments
- risk assessments
- project cost estimation
- project timing and delivery.

These are discussed in turn below.

C5.1 Demand forecasts

Refer to chapter 3 of this report for information on how we develop and use demand forecasts.

C5.2 Asset health and condition assessments

Our Transmission Asset Life Cycle (TALC) assessment framework employs a range of factors to determine where an asset is in its life cycle. The framework assists in optimising our asset management decisions. Our assessment considers both the technical health (condition, serviceability, maintainability, operability and safety) of the asset and its strategic importance in the network (related to the level of risk).

We apply a systematic, continuous process for collecting, recording and analysing detailed information on the condition of our network assets.

These asset health and condition assessments and the ongoing improvement in our understanding of our assets are key inputs to the asset management planning process and the development of asset replacement and refurbishment programs.

C5.3 Planning and design standards

Our planning standards are derived from the Rules and the ETC, and are presented in more detail in section C2.1. The ETC establishes the specific reliability standards that apply to each exit point on the transmission network. Connection point power factor requirements are reflected in customer connection agreements.

We have developed and maintain a comprehensive set of design and construction standards in order to comply with the requirements of our SRMTMP. This plan is required by section 15 of the Electricity Act 1996 (SA) to demonstrate that our infrastructure complies with good electricity industry practice and the standards referred to in the Act.

C5.4 Network modelling

We use the Siemens Power Technologies International PSS/E suite of power system analysis programs as the platform for identifying both operational and future network limitations, as is the case for most other Australian TNSPs, DNSPs and AEMO. Our network model is provided to AEMO and is, therefore, subject to regular scrutiny by independent power industry experts.

Plant data is based on primary sources such as transmission line impedance tests, generator commissioning and compliance tests, power transformer test certificates and on secondary sources such as line impedances calculated from first principles.

C5.5 Economic assessments

We conduct an economic assessment to review the available options, costs, benefits, and optimal timing for all large projects to ensure that any investment we make maximises the net benefit to customers. The outcomes of these assessments reflect current information, and are updated as further information and analysis becomes available.

The options generally considered include ‘business as usual’, network solutions, deferred network investment, and non-network alternatives. Only if a network investment is clearly shown to be the least cost solution do we include such a project in our capital expenditure forecast.

Inputs considered in these assessments include:

- capital and operating costs of alternative options
- reliability benefits – where unserved energy is measured by the Value of Customer Reliability (VCR) estimates published by AEMO[58]
- cost savings – for example avoided maintenance costs
- risk reduction – as measured by the quantified value of the risk reduced or avoided through the project (for example avoided environmental contamination)
- standard discount rate assumptions – based on a range of estimates including commercial rates and the prevailing regulated rate of return
- optimal timing – including the potential for deferral of an investment to a subsequent regulatory period

Sensitivity testing is also conducted to determine the robustness and level of confidence in the outcomes of these economic assessments.

The RIT-T is applied to all projects that meet the criteria that are set in the Rules.

C5.6 Non-network alternatives

We consider the scope for non-network alternatives when we address identified needs on the network.

C5.7 Risk assessments

For projects driven primarily by risk mitigation (including, for example, safety, reliability and environmental risks), a detailed risk assessment is undertaken to estimate and quantify the risk involved, as a key input to the economic analysis of available options to address the risk.

This risk analysis considers:

- probability of an asset failure
- likelihood of adverse consequence(s)
- likely cost(s) of the consequence(s).

This is based on a systematic process for collecting, recording and analysing detailed information on the condition of network assets, and balances the expected risk reduction against the costs of the proposed expenditure to ensure safety and reliability requirements are met at lowest cost.

We rely on detailed asset condition and risk information to develop specific plans for capital replacement and refurbishment projects for different asset categories and key risk areas, such as asset operational integrity, and safety and environmental issues. A decision to replace an asset is driven by considerations of detailed asset condition, risk, and reliability, balanced against the cost of replacement.

C5.8 Project cost estimation

Project cost estimates are derived as described earlier in section C4.5.

C5.9 Project timing and delivery

We prioritise the delivery of our capital program to ensure that the capital expenditure objectives are met as efficiently as possible. Our capital expenditure forecasts reflect the latest information on the timing of current projects, which is continually updated as projects proceed.

C6 Further information on ElectraNet’s asset management strategy and methodology

Further information can be obtained from:

consultation@electranet.com.au

[58] *AEMO, Value of Customer Reliability Review Final Report, September 2014, available at www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.*

Appendix D: Compliance checklist

This appendix sets out a compliance checklist which demonstrates the compliance of ElectraNet's 2021 Transmission Annual Planning Report with the requirements of clause 5.12.2(c) of version 173 of the Rules (the latest version at time of writing).

Item	Sub-item	Summary of requirements	Section
		The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[59] and set out:	
(1)		the forecast loads submitted by a Distribution Network Service Provider in accordance with clause 5.11.1 or as modified in accordance with clause 5.11.1(d), including at least:	Chapter 3, and our Transmission Annual Planning Report web page[60]
	(i)	a description of the forecasting methodology, sources of input information, and the assumptions applied in respect of the forecast loads;	
	(ii)	a description of high, most likely and low growth scenarios in respect of the forecast loads;	
	(iii)	an analysis and explanation of any aspects of forecast loads provided in the Transmission Annual Planning Report that have changed significantly from forecasts provided in the Transmission Annual Planning Report from the previous year; and	
	(iv)	an analysis and explanation of any aspects of forecast loads provided in the Transmission Annual Planning Report from the previous year which are significantly different from the actual outcome;	
(1A)		for all network asset retirements, and for all network asset de-ratings that would result in a network constraint, that are planned over the minimum planning period specified in clause 5.12.1(c), the following information in sufficient detail relative to the size or significance of the asset:	Sections 6.2, 7.7, 7.9 and our Transmission Annual Planning Report web page[62]
	(i)	a description of the network asset, including location;	
	(ii)	the reasons, including methodologies and assumptions used by the Transmission Network Service Provider for deciding that it is necessary or prudent for the network asset to be retired or de-rated, taking into account factors such as the condition of the network asset;	
	(iii)	the date from which the Transmission Network Service Provider proposes that the network asset will be retired or de-rated; and	
	(iv)	if the date to retire or de-rate the network asset has changed since the previous Transmission Annual Planning Report, an explanation of why this has occurred	
(1B)		for the purposes of subparagraph (1A), where two or more network assets are:	Sections 6.2, 7.9 and our Transmission Annual Planning Report web page[62]
	(i)	of the same type;	
	(ii)	to be retired or de-rated across more than one location;	
	(iii)	to be retired or de-rated in the same calendar year; and	
	(iv)	each expected to have a replacement cost less than $200,000 (as varied by a cost threshold determination),	
		those assets can be reported together by setting out in the Transmission Annual Planning Report:	
	(v)	a description of the network assets, including a summarised description of their locations;	
	(vi)	the reasons, including methodologies and assumptions used by the Transmission Network Service Provider, for deciding that it is necessary or prudent for the network assets to be retired or de-rated, taking into account factors such as the condition of the network assets;	
	(vii)	the date from which the Transmission Network Service Provider proposes that the network assets will be retired or de-rated; and	
	(viii)	if the calendar year to retire or de-rate the network assets has changed since the previous Transmission Annual Planning Report, an explanation of why this has occurred	
(2)		planning proposals for future connection points	Section 5.6
(3)		a forecast of constraints and inability to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction over 1, 3 and 5 years, including at least:	Chapter 7 and our Transmission Annual Planning Report web page[62]
	(i)	a description of the constraints and their causes;	
	(ii)	the timing and likelihood of the constraints;	
	(iii)	a brief discussion of the types of planned future projects that may address the constraints over the next 5 years, if such projects are required; and	
	(iv)	sufficient information to enable an understanding of the constraints and how such forecasts were developed	

[59] The AER's TAPR Guidelines are available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/transmission-annual-planning-report-guidelines.

[60] Our Transmission Annual Planning Report web page is available at https://www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/.

Item	Sub-item	Summary of requirements	Section
		The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[59] and set out:	
(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:	Section 5.7, section 7.4 and our Transmission Annual Planning Report web page[62]
	(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, replacement of network assets, 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	
(5)		for all proposed augmentations to the network and proposed replacements of network assets the following information, in sufficient detail relative to the size or significance of the project and the proposed operational date of the project:	Sections 7.3 to 7.9
	(i)	project/asset name and the month and year in which it is proposed that the asset will become operational;	
	(ii)	the reason for the actual or potential constraint, if any, or inability, if any, to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction, including load forecasts and all assumptions used;	
	(iii)	the proposed solution to the constraint or inability to meet the network performance requirements identified in subparagraph (ii), if any;	
	(iv)	total cost of the proposed solution;	
	(v)	whether the proposed solution will have a material inter-network impact. In assessing whether an augmentation to the network will have a material inter-network impact a Transmission Network Service Provider must have regard to the objective set of criteria published by AEMO in accordance with clause 5.21 (if any such criteria have been published by AEMO); and	
	(vi)	other reasonable network options and non-network options considered to address the actual or potential constraint or inability to meet the network performance requirements identified in subparagraph (ii), if any. Other reasonable network and non-network options include, but are not limited to, interconnectors, generation options, demand side options, market network service options and options involving other transmission and distribution networks	
(6)		the manner in which the proposed augmentations and proposed replacements of network assets relate to the most recent Integrated System Plan	Section 2.1
(6A)		for proposed new or modified emergency frequency control schemes, the manner in which the project relates to the most recent power system frequency risk review	Section 2.2
(6B)		information about which parts of its transmission network are designated network assets and the identities of the owners of those designated network assets	Section 4.1.1
(7)		information on the Transmission Network Service Provider's asset management approach, including:	Appendix C
	(i)	a summary of any asset management strategy employed by the Transmission Network Service Provider;	
	(ii)	a summary of any issues that may impact on the system constraints identified in the Transmission Annual Planning Report that has been identified through carrying out asset management; and	
	(iii)	information about where further information on the asset management strategy and methodology adopted by the Transmission Network Service Provider may be obtained	
(8)		any information required to be included in an Transmission Annual Planning Report under:	Section 1.3.4, 7.2 and 7.4
	(i)	clause 5.16.3(c) and 5.16A.3 in relation to a network investment which is determined to be required to address an urgent and unforeseen network issue; or	
	(ii)	clauses 5.20B.4(h) and (i) and clauses 5.20C.3(f) and (g) in relation to network investment and other activities to provide inertia network services, inertia support activities or system strength services	
(9)		emergency controls in place under clause S5.1.8, including the Network Service Provider's assessment of the need for new or altered emergency controls under that clause	Sections 4.5 and 7.3
(10)		facilities in place under clause S5.1.10	Sections 4.5 and 7.3
(11)		an analysis and explanation of any other aspects of the Transmission Annual Planning Report that have changed significantly from the preceding year's Transmission Annual Planning Report, including the reasons why the changes have occurred	Appendix A
(12)		the results of joint planning (if any) undertaken with a Transmission Network Service Provider under clause 5.14.3 in the preceding year, including a summary of the process and methodology used by the Transmission Network Service Providers to undertake joint planning and the outcomes of that joint planning	Appendix B

Appendix E: Contingent projects

Contingent projects for the 2018-19 to 2022-23 regulatory control period

Project	Trigger[61]	Current status	Reference
Eyre Peninsula major upgrade Address asset retirement needs and continue to meet the reliability standard at Port Lincoln	Successful completion of the RIT-T including an assessment of credible options identifying the duplication or replacement of the existing Cultana-Yadnarie and/or Yadnarie-Port Lincoln transmission lines as the preferred option	Committed	Sections 6.2 and 7.5
Insufficient system strength Install synchronous condensers specifically designed to contribute strongly to fault currents at a central location or locations	Confirmation by AEMO of the existence of a Network Support and Control Ancillary Services (NSCAS) gap relating to system strength, or other requirement for ElectraNet to address a system strength requirement, in the South Australian region Successful completion of the RIT-T (or equivalent economic evaluation) including an assessment of credible options showing a transmission investment is justified	Committed	Sections 1.3.4, 2.1.1, 5.2.3 and 6.1
South Australian Energy Transformation Produce net market benefits, improve South Australian system security, and enable the further integration of generation from renewable resources	Successful completion of the South Australian Energy Transformation RIT-T with the identification of a preferred option or options: • demonstrating positive net market benefits and/or • addressing a reliability corrective action	Committed	Sections 1.3.1, 2.1.2, 6.2 and 7.3
Upper North region eastern 132 kV line upgrade Rebuild the Davenport to Leigh Creek 132 kV line	Customer commitment for additional load to connect to the transmission network causing the Davenport to Leigh Creek 132 kV line to exceed its thermal limit of 10 MVA Successful completion of the RIT-T including an assessment of credible options showing a transmission investment is justified	Project not triggered in 2018-19 to 2022-23 revenue control period	Section 7.5
Upper North region western 132 kV line upgrade Uprate or rebuild the Davenport to Pimba 132 kV line	Customer commitment for additional load to connect to the transmission network causing the Davenport to Pimba 132 kV line to exceed its thermal limit of 76 MVA Successful completion of the RIT-T including an assessment of credible options showing a transmission investment is justified	Project not triggered in 2018-19 to 2022-23 revenue control period	Section 7.5

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

Contingent projects being considered for the 2023-24 to 2027-28 regulatory control period

Project	Description	Trigger[62]	Customer Benefit	Indicative cost (A$M)
Eyre Peninsula Upgrade	This project allows for the upgrade of the northern section of the Eyre Peninsula lines from 132 kV to 275 kV to serve higher loads, which is accommodated in the design, and/or augmentation of power transfer capacity between Davenport and Cultana	1. Customer commitment for additional load to connect to the transmission network causing the Cultana 275/132 kV transformers to exceed their thermal limit of 200 MW and/or causing a need for augmentation of power transfer capacity between Davenport and Cultana 2. Successful completion of a RIT-T including an assessment of credible options showing the upgrade of the 132 kV Eyre Peninsula Link to 275 kV and/or augmentation of power transfer capacity between Davenport and Cultana is the preferred option a) demonstrating positive net market benefits; and/or b) addressing a reliability corrective action	This project will be required to support an increase in load on the Eyre Peninsula delivering increased economic benefits In addition, this project may also support the transition to 100% renewable generation and an economy-wide net zero emission target by increasing the networks capability to connect the abundant solar and wind resources on the Eyre Peninsula	**50 - 150**
Main Grid System Strength Support	This project allows for the delivery of additional system strength on the transmission network	1. AEMO declaring a system strength shortfall (or equivalent requirement) in South Australia and directing ElectraNet to remediate the shortfall 2. Successful completion of a RIT-T (or equivalent economic evaluation) including an assessment of credible options showing a transmission investment is justified	This project will support the grid's transition to 100% renewable generation and an economy-wide net zero emissions target	**80 - 120**
Interconnector Upgrade	This project would allow for an increase in inter-regional transfer capacity through such measures as control schemes and/or frequency response capability	Successful completion of a RIT-T with an identified need to increase inter-regional transfer capability between South Australia and adjoining regions a) demonstrating positive net market benefits; and/or b) addressing a reliability corrective action	This project would deliver net economic benefits and support the grid's transition to 100% renewable generation and an economy-wide net zero emission target while continuing to drive down energy costs across the grid through an indicative transfer capacity increase of up to 200-300 MW or more	**100 - 150**
Power Quality Management	This project allows for the installation of the relevant equipment to maintain power quality standards across the transmission network in relation to voltage harmonic and flicker requirements	Successful completion of a RIT-T including an assessment of credible options showing a transmission investment is justified to address voltage quality requirements on the South Australian transmission network.	This project will ensure power quality requirements are maintained for customers (namely voltage harmonic and flicker distortion) across the transmission network in line with accepted standards	**30 - 60**

[62] *In addition, the following trigger conditions applies to each of the projects listed:*
- *ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.*

The following table lists projects that will not be included in ElectraNet's 2023-24 to 2027-28 Revenue Proposal, but which will be triggered as contingent projects if AEMO's Integrated System Plan declares them as actionable projects. In that event, the triggers will include the completion of a Project Assessment Conclusions Report under the RIT-T and written confirmation from AEMO that the preferred option aligns with the ISP and that the cost does not change the status of the actionable ISP project as part of the optimal development path.

Proposed contingent projects that will be triggered by AEMO's ISP

Project	Description	Trigger[63]	Customer Benefit	Indicative cost (A$M)
Upper South East Network Augmentation	This project would increase transfer capacity between Tailem Bend and Adelaide to allow for greater imports and exports of renewable energy	This project will support the grid's transition to 100% renewable generation and an economy-wide net zero emission target As coal generators in the eastern states retire, this project is included in the ISP's optimal development pathway	AEMO's 2020 ISP forecast a need for the project in the mid-2030s with the project required as early as 2030 in the 2020 Step Change scenario An earlier timing in the upcoming 2022 ISP is probable given the future scenarios being considered are centred around the 2020 Step Change scenario and with multiple scenarios modelling a zero emissions economy by 2050	**30 - 50**
Davenport and Robertstown to Adelaide Transfer Capacity Increase (Potential ISP Project)	This project would increase transfer capacity between the Mid North and Adelaide to allow for delivery of increased renewable generation from the Mid North	This project will support the grid's transition to 100% renewable generation and an economy-wide net zero emission target As coal generators in the eastern states retire, this project is included in the ISP's optimal development pathway	AEMO's 2020 ISP forecast a need for the project in the mid-2030s with the project required as early as 2030 in the 2020 Step Change scenario An earlier timing in the upcoming 2022 ISP is probable given the future scenarios being considered are centred around the 2020 Step Change scenario and with multiple scenarios modelling a zero emissions economy by 2050	**200 - 250**

[63] In addition, the following two trigger conditions apply to each of the projects listed:

- *ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.*

Abbreviations

Abbreviation	Definition
°C	Degrees Celsius
AC	Alternating Current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMD	Agreed Maximum Demand
CBD	Central Business District
DER	Distributed Energy Resources
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities, published by AEMO
ETC	Electricity Transmission Code
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
FFR	Fast Frequency Response
GPSRR	General Power System Risk Review
HVAC	High voltage alternating current
HVDC	High voltage direct current
Hz	Hertz
ISP	Integrated System Plan, published by AEMO
kV	kilo-Volt, a unit of voltage
LOPA	Layer of Protection Analysis
Mvar	Mega-volt-ampere-reactive, a unit of reactive power
MW	Mega-watt, a unit of active power
MVA	Mega Volt-Ampere, a unit of apparent power
NCIPAP	Network Capability Incentive Parameter Action Plan
NEM	National Electricity Market
NSP	Network Service Provider
OFGS	Over Frequency Generator Shedding
OLTC	On load tap changer
OTR	Office of the Technical Regulator
POE	Probability of Exceedance
PACR	Project Assessment Conclusions Report
PSCR	Projects Specification Consultation Report
PSFRR	Power System Frequency Risk Review
PV	Photo-voltaic
RoCoF	Rate of change of frequency
RMU	Ring Main Unit
RTU	Remote Terminal Unit
Rules	National Electricity Rules
SIPS	System Integrity Protection Scheme
SRMTMP	Safety, Reliability, Maintenance and Technical Management Plan
SVC	Static Var Compensator
TUOS	Transmission Use of System Services
REZ	Renewable Energy Zone, as defined in AEMO's ISP
RIT-T	Regulated Investment Test for Transmission
TNSP	Transmission Network Service Provider
UFLS	Under Frequency Load Shedding
VCR	Value of Customer Reliability
VPP	Virtual Power Plant
WAMS	Wide Area Monitoring Scheme
WAPS	Wide Area Protection Scheme

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
Contraint	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	One of ElectraNet's seven regional networks in South Australia
Eyre Peninsula	One of ElectraNet's seven regional networks in South Australia
Frequency control ancillary service	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
Adelaide Metropolitan	One of ElectraNet's seven regional networks in South Australia
Mid North	One of ElectraNet's seven regional networks in South Australia
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
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
Registered participants	As defined in the Rules
Riverland	One of ElectraNet's seven regional networks in South Australia
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
South East	One of ElectraNet's seven regional networks in South Australia
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	One of ElectraNet's seven regional networks in South Australia
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

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