Transmission Annual Planning Report

October 2022

ElectraNet

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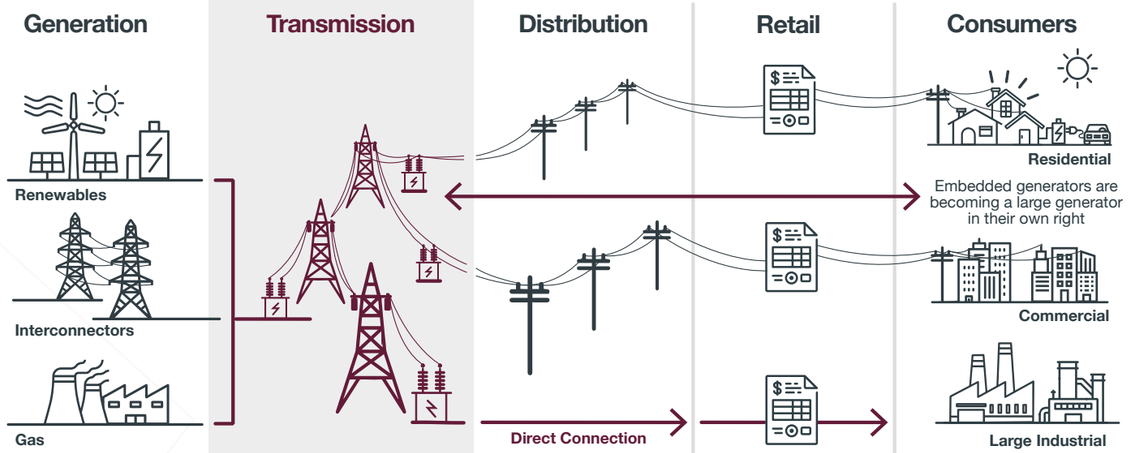
About ElectraNet

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



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

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.

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

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

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.

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

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 (ISP) 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 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 2022 to 31 October 2032) and identifies potential network capability limitations and possible solutions.

The report provides information on:

- trends and directions for the future of the electricity transmission system *(Chapter 1)*
- national transmission planning *(Chapter 2)*
- demand forecasts 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)*.

This report forms 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 and affordable electricity transmission services.

Comments and suggestions can be directed to:

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Executive Summary

South Australia's energy transformation is accelerating and irreversible as South Australia sets its sights on exporting renewable electricity to the nation and the world.

South Australia remains at the forefront of changes sweeping electricity systems worldwide. Generation from renewable energy sources reached 68 per cent of South Australia's total electricity generation in 2021-22, progressing towards the South Australian Government's target of net 100 per cent renewable energy generation by 2030.

With projected connections of new renewable generators on our network, we predict South Australia will meet and exceed this target. Our state will soon afterwards become a net exporter of renewable energy, supporting Australia's legislated emissions reduction targets.

Drivers of change

Replacing dispatchable capacity

Interest in utility-scale Battery Energy Storage Systems (BESSs) is unprecedented in its ambition and appears likely to far outstrip forecasts across all scenarios in the Australian Energy Market Operator's (AEMO's) 2022 Integrated System Plan (ISP).

> **Electrification of the transport sector has commenced with electric vehicles comprising around 2% of new passenger car sales in 2021-22.**

Major loads and electrification

Large new loads may connect over the short to medium-term including mines, cryptocurrency data centres and large industrial customers seeking to take advantage of South Australia's renewables-based electricity. These large step loads are difficult to forecast ahead of investment commitment.

Widespread electrification of customer demand is forecast to commence this decade, to reduce emissions, and avoid expensive carbon-based gas fuel. AEMO's 2022 Electricity Statement of Opportunities (ESOO) forecasts that industrial loads will electrify first, causing demand and energy growth on the transmission network.

Electrification of the transport sector has commenced with electric vehicles comprising around 2 per cent of new passenger car sales in 2021-22. This is expected to accelerate over the remainder of the 2020s, with widespread uptake of electric vehicles anticipated by 2030. The mobility of electric vehicles adds further complexity to forecasting network needs.

The potential for hydrogen

The emergence of a hydrogen production industry in South Australia could be a significant driver of growth, regionally and statewide. To accommodate a large hydrogen production industry, the South Australian grid will need to evolve to a global-scale network delivering amounts of energy that greatly exceed its existing capability. This will create opportunities to reduce the cost of electrical energy for South Australian customers.

The potential for massive demand growth is illustrated in AEMO's Integrated System Plan by the *Hydrogen Superpower* scenario.

The South Australian Government's Hydrogen Jobs Plan is forecast to be operational by 2025, giving the South Australian hydrogen industry a substantial boost and including about four months of hydrogen storage for the proposed hydrogen-fired generator, "firming up" electricity generation from intermittent renewables. We are working with the South Australian Government and industry to support these plans.

Declining minimum demand

At the same time, the ongoing consumer adoption of distributed solar PV is reducing the minimum demands drawn from the transmission system on mild, sunny days. Net negative South Australian operational demand was observed during several five-minute dispatch intervals in November 2021. Consequently, the South Australian electricity system needs to accommodate a wider range of loading levels than ever before, creating voltage control and other challenges for the transmission network.

Beyond minimum demand, the rapidly changing nature of devices that are connected to the distribution and transmission networks are complicating the operation of the network. AEMO's Engineering Framework[1] is seeking to enable customer decisions while ensuring the network remains operable.

The rise of distributed solar PV is impacting on the largest contingencies that need to be managed by the grid. This has led to an increased requirement for inertia on the South Australia system from 2023-24. We are supporting AEMO as they prepare the network for these changes, including through the acquisition of more Fast Frequency Response to manage forecast inertia shortfalls.

[1] *Details available at https://www.aemo.com.au/initiatives/major-programs/engineering-framework.*

What are we doing about it

ElectraNet has an important role to play in addressing these challenges and priorities.

We are at the forefront of providing a system capable of 100% renewable generation that continues to provide the services expected by customers: a system that balances affordability with reliability.

In October 2021 we completed installation of four synchronous condensers. The synchronous condensers enable South Australia's transmission network to be operated securely with only two large conventional generator units in-service. The synchronous condensers have delivered even greater benefits than anticipated, allowing increased renewable generation in South Australia and dramatically reducing the cost to consumers of directions to conventional generators.

ElectraNet is the original proponent of Project EnergyConnect, the new electricity interconnector between South Australia and New South Wales, and the largest transmission project in Australia. In February 2022 we commenced construction of the South Australian component of this project of national significance. Transgrid is responsible for construction of the New South Wales component of the project. Project EnergyConnect will support the ongoing transformation of the power system and drive down energy costs across the National Electricity Market (NEM).

Project EnergyConnect remains on track to be completed in two stages:

- the completion of construction from Robertstown in South Australia to Buronga in New South Wales, energisation and commissioning in late 2023, with inter-network testing and release of initial transfer capability up to 150 MW over the following 6 months
- the completion of the second section, from Buronga to Wagga Wagga in New South Wales, energisation and commissioning in late 2024, with inter-network testing and release of transfer capacity up to 800 MW over 12-18 months, subject to market demand.

Opportunities to accelerate inter-network testing timeframes are under active consideration for this project of national significance.

Combined with the synchronous condensers, Project EnergyConnect will facilitate the operation of the South Australian system with no conventional generator units in service, putting South Australia on track to be the first gigawatt-scale system in the world capable of operating with 100% inverter-based renewable energy generation. Prior to Project EnergyConnect we are determining system limits that would apply with only one large conventional generator unit in-service, to further reduce the cost to consumers of directions to conventional generators.

In March 2021 we commenced construction of Eyre Peninsula Link, our replacement project to address the condition of the Eyre Peninsula 132 kV network. It will provide a new double circuit 132 kV electricity transmission line from Cultana to Port Lincoln, improving electricity reliability and security for Eyre Peninsula and catering for future increases in electricity demand and new renewable generation connections. Energisation and commissioning is expected in January 2023.

We are also implementing special protection schemes to protect the power system from disturbances in an increasingly complex operating environment and to maximise network transfer capability.

AEMO's Engineering Framework[2] and ISP also highlight that to ensure the NEM power system can operate securely with high penetration of inverter-based resources, the system operator and network service providers like ElectraNet will need to uplift their capabilities in operational systems, processes, real time monitoring and power system modelling. We are working closely with AEMO and other stakeholders to develop a roadmap for the uplift required to operate the NEM securely with 100% renewables, and are seeking to progress the systems and capability uplift required to protect the power system from disturbances in an increasingly complex operating environment.

[2] *https://aemo.com.au/initiatives/major-programs/engineering-framework.*

ElectraNet is at the forefront of providing a 100% renewable system that continues to provide the services expected by customers: a system that balances affordability with reliability.

The next 10 years… and beyond

In our planning, we focus on ensuring system security and reliability, forecast network limitations and opportunities, and ensure plans are in place to address these in a timely and efficient manner. We also look further ahead and assess potential major developments over a 20-year period as we consider AEMO's ISP and the strategies needed to unlock the full potential of the identified Renewable Energy Zones in South Australia. In doing this, we have also cast our minds to the future to imagine a transmission strategy that can accommodate the massive network expansion that would be needed to support a South Australian hydrogen export industry.

Over the next five years, capital investment in the transmission network will be dominated by prioritised asset replacement and refurbishment to ensure plant safety and reliability and to minimise lifecycle costs.

Capital investment is also needed to address the challenges emerging from the increasing penetration of distributed energy resources. This includes additional reactive support to maintain an adequate reserve of dynamic reactive power capability at times of low or negative net system demand, and 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.

Over the medium to long-term there are emerging opportunities for massive growth of electricity demand within South Australia. For example, under AEMO's Step Change scenario, which forms the basis of this plan, energy consumption in South Australia is projected to double by 2050 driven by electrification of the economy. Under the *Hydrogen Superpower* scenario energy consumption in South Australia is projected to be 20 times more than today by 2050.

Our planning will continue to investigate the transmission network implications of these scenarios.

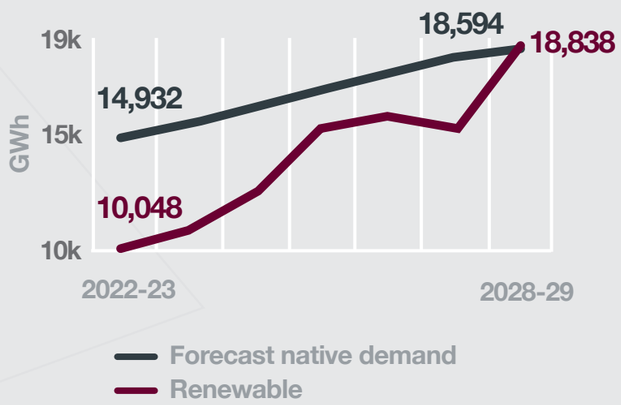
We have identified potential future projects in line with AEMO's 2022 ISP. These include investments to increase transfer capacity between South East, Tailem Bend and Adelaide (South East SA REZ Expansions), and between Mid North and Adelaide (Mid North SA REZ Expansion). Aside from benefiting intra-regional transfer capacities for renewable energy, these projects would optimise interstate transfer capability between the Heywood interconnector, Project EnergyConnect interconnector and Murraylink interconnector.

We continue to participate in the ongoing national conversation about energy transformation and engage in joint planning with AEMO, other Transmission Network Service Providers, and SA Power Networks to develop plans to support the changing needs of customers and consumers.

South Australia's transforming power system

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

Journey towards 100% renewable electricity generation



2016

- Coal fired generation ceased — May 2016

2017

- Statewide blackout — September 2016

2018

- First AEMO Integrated System Plan — June 2018
- World's largest battery Hornsdale Power Reserve connected

2019

- ElectraNet Dalrymple battery is first grid forming battery in Australia
- Connection of first grid scale solar plant at Bungala

2020

- ElectraNet synchronous condensers begin operation

2021

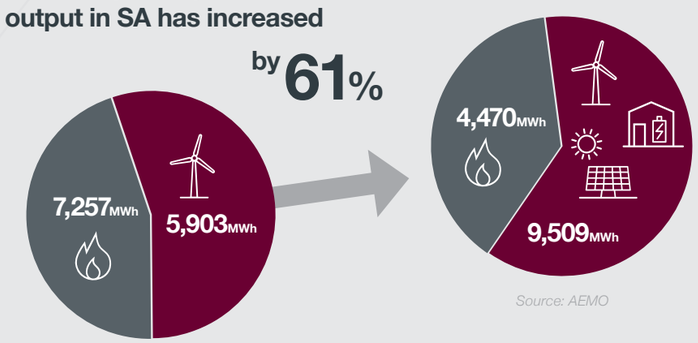
- Regulatory approval for new interconnector to NSW Project EnergyConnect — June 2021
- Negative system demand reached — November 2021
- Construction begun on the Eyre Peninsula Link — March 2021

2022

- Fast Frequency Response services contracted — July 2022
- Retirement of first major gas-fired power station
- Construction begun on the Project EnergyConnect interconnector — May 2022

Renewables are replacing gas

Over the past 6 years renewables output in SA has increased by **61%**



Source: AEMO

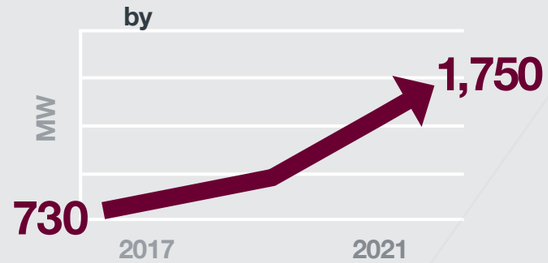
In just over 16 years the State's renewable energy output has increased more than 10 times

68%

6%

A grid in transition

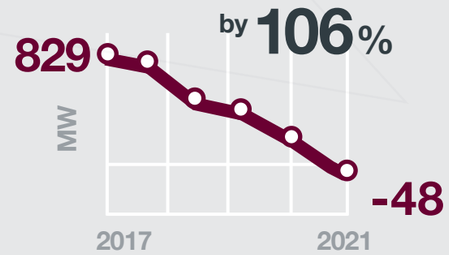
Rooftop PV installation has increased over the past 6 years by



Source: AEMO

Source: ACCC

Minimum grid demand has decreased over the past 5 years by **106%**



Source: AEMO

The Network of the future

2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030

Eyre Peninsula Link
A new double-circuit 132 kV electricity transmission line from Cultana to Port Lincoln

Project EnergyConnect Stage 1
Completion from Robertstown in SA to Buronga in NSW in late 2023, with release of initial transfer capacity of up to 150 MW over the following 6 months

Project EnergyConnect Stage 2
Completion of the section from Buronga to Wagga Wagga in NSW, with release of transfer capacity up to 800 MW over 12-18 months operating environment subject to market demand

We continue to engage in joint planning with AEMO, other Transmission Network Service Providers, and SA Power Networks to develop plans to support the changing needs of customers and consumers

We are thinking about the future, imagining a transmission strategy which accommodates an expanded network to support a SA hydrogen export industry.

Fast Frequency Response
First FFR services contracted from 1 July 2022. We are engaging with the market for additional FFR services from 1 July 2023 until Project EnergyConnect is energised

Special protection schemes
Implement a Wide Area Monitoring Scheme and a Special Protection Scheme to manage the increasingly complex operating environment

Hydrogen Jobs Plan
Construction of a world-leading 200 MW hydrogen power station, 250 MW electrolyser and 3,600 tonne storage facility

A renewables future
AEMO's goal to have the NEM power system capable of managing periods of 100% instantaneous penetration of renewable energy

We are exploring options to unlock the South East SA REZ and Mid North SA REZ, to inform AEMO's 2024 ISP

2024-2028 Revenue Proposal

100%

SA forecast to achieve 100% net renewable electricity generation

Revenue proposal for the 2024-2028 revenue control period

Addresses the challenges presented by the ongoing energy transformation, and keep the existing ageing network going for longer

We are proposing targeted capital investment to address the challenges arising from the increasing penetration of distributed energy resources:

- Additional reactive support for times of low or negative net system demand.
- Expand our Wide Area Monitoring Scheme.

We are at the forefront of providing a 100% renewable electricity system that continues to provide the services expected by customers: balancing affordability with reliability

2022 Highlights

Solving system strength

We 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. This has significantly reduced the cost to customers of directions to synchronous generators to operate and provide system strength service.

Eyre Peninsula Link

After almost 50 years in service, the Eyre Peninsula's existing 132kV electricity transmission line is approaching the end of its operational life.

Eyre Peninsula Link will replace the existing 132 kV lines between Cultana and Port Lincoln with a new double-circuit line between Cultana and Yadnarie – 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. Eyre Peninsula Link will provide the Eyre Peninsula with a more reliable and secure electricity supply and cater for electricity demand for the next 50 years.

Construction of the new transmission line commenced in March 2021 and the transmission line is expected to be energised by January 2023

Once completed, the new double circuit line will provide opportunities for new renewable energy and mining projects to connect to the network.

Project EnergyConnect

Project EnergyConnect involves the construction of a new 330 kV interconnector (approximately 900 km in total length) between Robertstown in South Australia and Wagga Wagga via Buronga in New South Wales, with a link at Buronga to renewable energy generators at Red Cliffs, in northwest Victoria. The South Australian component includes 206 km of transmission line, along with a new substation at Bundey and upgrades to the existing Robertstown and Tungkillo substations.

Implementation of Project EnergyConnect is anticipated to increase the maximum amount that can be transferred across the Heywood interconnector 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.

Project EnergyConnect will deliver a range of direct benefits for consumers including lower power prices, improved energy security and increased economic activity. Opportunities will also be created for regional communities through job creation and local procurement during construction and, in the longer term, as new energy projects come online.

Construction commenced in February 2022 and remains on track to be delivered in two stages:

- The completion of construction from Robertstown in South Australia to Buronga in New South Wales, energisation and commissioning in late 2023, with inter-network testing and release of initial transfer capability up to 150 MW over the following 6 months
- The completion of the second section from Buronga to Wagga Wagga in New South Wales, energisation and commissioning in late 2024, with inter-network testing and release of transfer capacity up to 800 MW over 12-18 months, subject to market demand.

Opportunities to accelerate inter-network testing timeframes are under active consideration for this project of national significance.

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 (NCIP) Action Plan, as well as new proposed projects to relieve constraints in our 2023-24 to 2027-28 NCIP Action Plan.

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 March 2023.

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.

AEMO published its final report for the 2022 Power System Frequency Risk Review (PSFRR) in July 2022. The 2022 PSFRR recommended revisions to constraints on the Heywood interconnector associated with the existing protected event for destructive wind conditions in South Australia. It also indicated AEMO's intention to explore options to forecast and manage future National Electricity Market ramping events (such as have been identified in South Australia during 2021) resulting from the increasing penetration of distributed solar PV generation and transmission-connected inverter-based resources.

In 2023 AEMO will undertake the first General Power System Risk Review (GPSRR), which replaces the Power System Frequency Risk Review (PSFRR). This will have a broader scope to explore a wider range of risks that could have adverse impacts on the power system We are assessing the impact that this will have on our planning processes and priorities.

System security

AEMO's 2021 review of inertia needs across the NEM confirmed the shortfall that was declared in 2020, for 200 MW of fast frequency response or equivalent inertia support activities, until 30 June 2023. We have contracted with third parties for the provision of the required services, as this is the lowest cost option to provide these services.

AEMO also declared a new shortfall, equivalent to 360 MW of fast frequency response or equivalent inertia support activities, from 1 July 2023 until the expected completion of Project EnergyConnect. We plan to again engage the market for provision of the required services.

We have identified an emerging need to augment the reactive power reserve of the transmission network at times of low system demand. One option to address this need is to install a suite of 50-60 Mvar 275 kV reactors at various locations on our network, to maintain an appropriate reserve of dynamic reactive power capability at times of low or negative net system demand. We will test the technical and economic merits of this option and viable alternatives as we apply the Regulatory Investment Test for Transmission (RIT-T).

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.

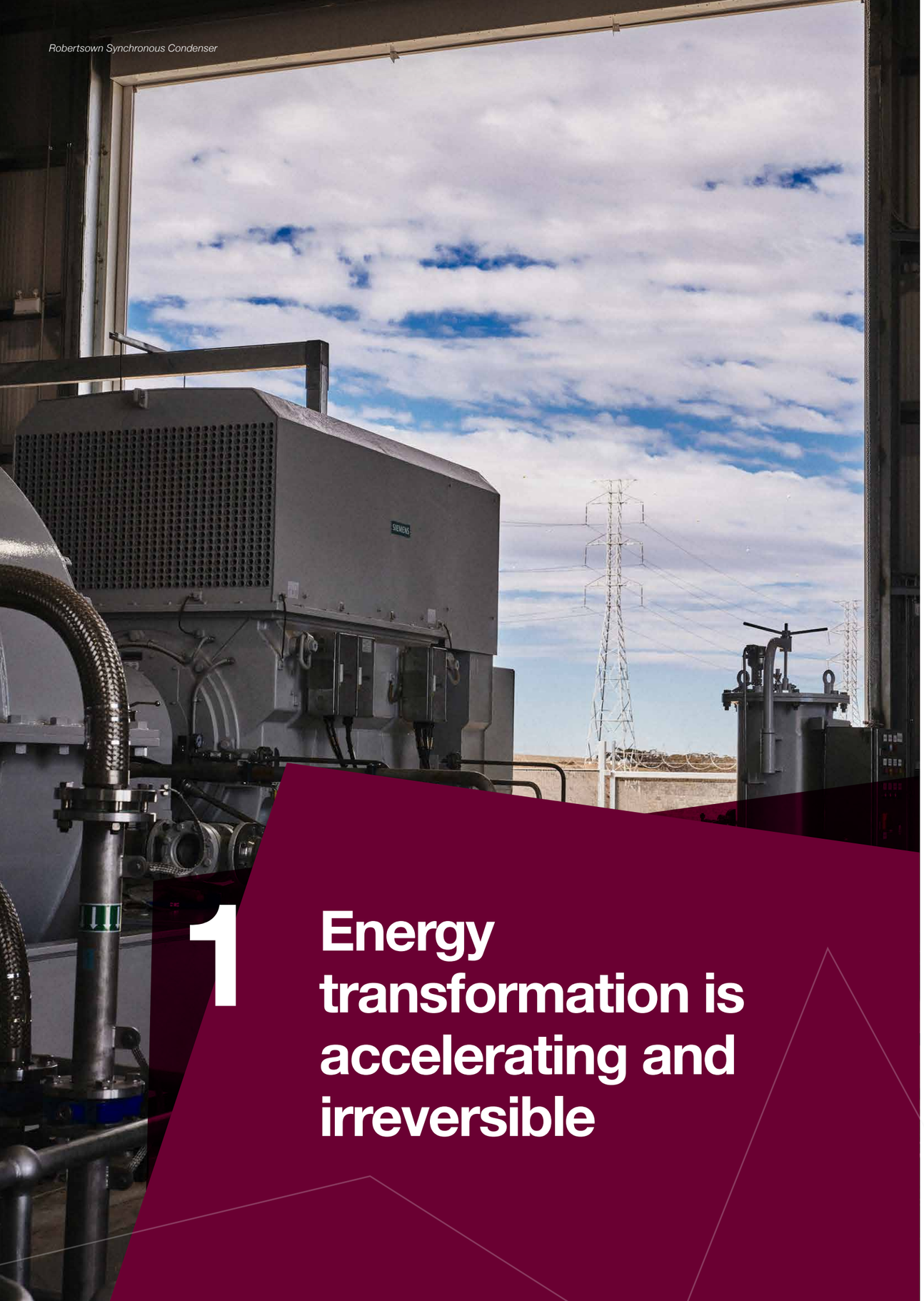
New connections

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, battery energy storage system and load developments across South Australia.

We are investigating opportunities to increase transfer capability through the Mid North to allow increased power transfers between regions in the north of the South Australia and the major 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. This will address the potential future need to enhance the capability of the South East SA and Mid North SA REZs as indicated in AEMO's 2022 ISP.

South Australia's energy transformation is presenting opportunities to connect large new loads to the transmission network. It is highly likely that the emergence of a hydrogen industry in South Australia will add significant load to the transmission network. In addition to hydrogen production, there are other significant sources of potential demand growth that may eventuate over the short to medium-term horizon. These include large new loads such as mines, cryptocurrency data centres and other large industrial customers seeking to take advantage of South Australia's low-cost and low-emission electricity from renewable sources.



Robertsown Synchronous Condenser

1 Energy transformation is accelerating and irreversible

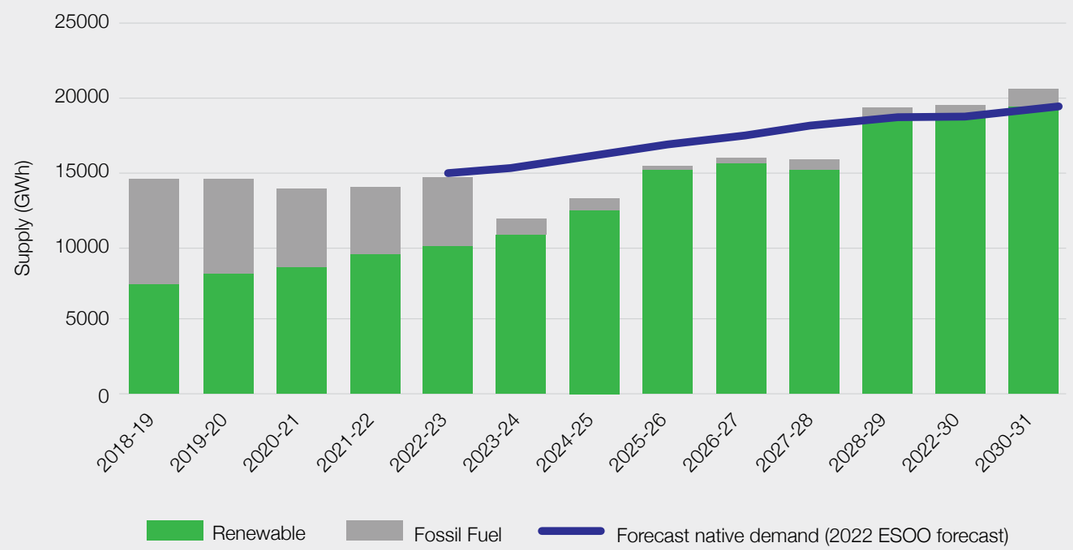
1.1 South Australia's journey towards 100% renewable electricity generation

South Australia's energy transformation is accelerating. The amount of small-scale and large-grid scale renewables connected to the transmission and distribution networks continues to increase. The pace of change is expected to increase further now that the Federal Government has legislated emission reduction targets and the industrial sector is generally supporting net zero emission by 2050.

The South Australian Government has targeted net 100% renewable electricity generation by 2030 and is working towards establishing new industries such as green hydrogen production and exports.

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 (Figure 1). Energy from renewable sources is estimated to have represented about 68% of South Australian electricity generation in 2021-22 and is forecast to exceed 100% of South Australian demand by 2028-29.

Figure 1: Historical and forecast South Australian generation from renewable and fossil-fuel sources



Sources: 2018-19 and 2019-20 data from AEMO's 2020 South Australian Electricity Report; 2020-21 data from AEMO's 2021 South Australian Electricity Report; 2021-22 and 2022-23 data from AEMO's 2022 South Australian Generation Forecasts report; forecast native demand (including load supplied by rooftop solar PV) from AEMO's forecasting data portal, 2022 ESOO Central (Step Change) scenario; forecast generation data from AEMO's 2022 ISP – Step Change scenario.

South Australia is forecast to reach 100% renewable electricity generation by 2028, ahead of the South Australian Government target of 2030.

South Australians have adopted distributed solar PV generation at world-leading rates. Three quarters of transmission connection points have experienced times when the output of distributed solar PV systems exceeded the local demand during the day. When this happens, the transmission network transports the excess electricity away from the local area, to be used by customers elsewhere.

At the state-wide level, net negative South Australian operational demand was observed during several five-minute dispatch intervals in November 2021. This is expected to occur more frequently in the future, meaning that at such times all demand in the state is met by distribution connected generators (predominantly distributed 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 connection enquiries and applications we expect that generation from South Australian renewable sources is likely to continue to increase. Along with continued uptake of distributed solar PV, the state is on track to reach 100% net renewables ahead of the 2030 target.

As a result, plans to strengthen parts of the electricity transmission system may need to be accelerated. Similarly, ambitious hydrogen production targets may require transmission and additional green generation across the state.

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 transformation

South Australia's transmission network is becoming more complex as it aims to reduce emissions and long-term costs.

The continued connection of intermittent renewable generation – at both transmission and distribution levels – is creating greater variability in electricity generation and demand and is challenging the power system's technical limits. This presents new challenges to reliability, affordability and system security.

ElectraNet plays a critical role 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 installed four synchronous condensers to supply essential system services that are being lost as conventional generators retire. We are also implementing special protection schemes to protect the power system from disturbances in an increasingly complex operating environment.

We have commenced provision from 1 July 2022 of contracted fast frequency response (FFR) services to address the South Australian inertia shortfall identified by AEMO. We are engaging with the market for the provision of additional FFR services from 1 July 2023 until Project EnergyConnect is energised and a special protection scheme is operational.

Our annual planning process focuses on balancing system security, reliability of supply and cost. 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.

AEMO's ISP highlights that to ensure the NEM power system can operate securely with high penetration of inverter-based resources, the system operator and network service providers like ElectraNet will need to uplift their capabilities in operational systems, processes, real time monitoring and power system modelling. We are working closely with AEMO and other stakeholders to develop a roadmap for the uplift required to operate the NEM securely with 100% renewables, and are seeking to progress the systems and capability uplift required to protect the power system from disturbances in an increasingly complex operating environment.

1.2 Network Vision, future directions and priorities

Our Network Vision is that **South Australia's electricity transmission network will support customer choice and deliver affordable and reliable power supplies for a sustainable future**.

To deliver these outcomes, 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.

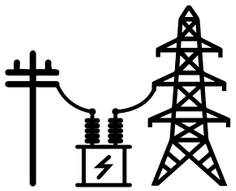
We also engage with customer representatives and other stakeholders to ensure we understand their concerns, needs, priorities and points of view to enhance our ability to plan and develop the transmission network so it delivers the greatest possible value.

Through this engagement customers have told us they see an important ongoing role for the transmission network in driving affordable and reliable electricity supply, while harnessing the benefits of new services and technology. 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.[2]

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

↑474 MW

is forecast to increase by 474 MW to 3,758 MW by 2030

We will continue to maintain the existing network through a risk-based framework focused on asset management objectives agreed with our customers.

The focus of our programs remains on asset replacement and refurbishment driven by the need to manage safety, security and reliability across an ageing network.

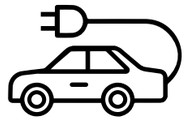
THEME 2

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

Rooftop PV

3,950 MW

rooftop PV to exceed 3,950 MW by 2030



Electric Vehicles

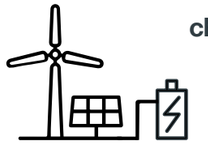
3.8%

Electric vehicles to consume 508 GWh of energy by 2030 adding 3.8% to demand

We are working in partnership with SA Power Networks to manage the growing challenges of reverse power flows and falling minimum demand levels.

This includes targeted investments in voltage control and power quality investigation, and implementing a wide area monitoring scheme to provide network performance information and maximise our ability to accommodate distributed generation on the network.

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 SA Government targeting net 100% renewables by 2030

Grid Scale Storage

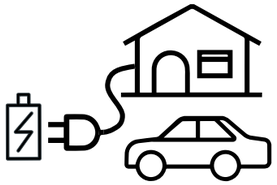
473 MW

Grid scale storage to reach 473 MW by 2030

We will continue to work with AEMO to maintain a secure power system, including implementing special protection and control schemes and delivering system services such as system strength and inertia to maintain secure and reliable operation of an increasingly complex power system.

THEME 4

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



Virtual Power Plants

397 MW

Virtual power plants to reach 397 MW by 2030

We are pursuing targeted investments in technology that deliver value for customers to maintain and improve key capabilities and working to identify a broader role for distributed energy resources in meeting future supply needs.

Figures updated for AEMO's 2022 ISP

[2] Our 2021 Network Vision is available at 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 point to maximum demands increasing over the next 10 years while minimum demands reduce (section 3). ElectraNet will need to maintain the network's capability to transmit electricity and provide essential services.

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

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) We engaged with our Consumer Advisory Panel working group to develop of our Revenue Proposal for the 2024-2028 regulatory control period We have started investigating opportunities to support further development of South Australian Renewable Energy Zones
	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 have considered a range of potential contingent projects for inclusion in our Revenue Proposal for the 2024-2028 regulatory control period (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) We have started investigating interconnector expansion opportunities beyond the scope of Project EnergyConnect
	Build trust through ongoing genuine engagement with customers and their representatives and other stakeholders	We published our Revenue Proposal for the 2024-2028 regulatory control period in June 2022 after a successful consultation process
	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 industry. The uptake of distributed energy resources in South Australia continues at world leading levels.

South Australia had around 1,750 MW of solar PV connections as of May 2022. At the state-wide level, net negative South Australian operational demand was observed during several five-minute dispatch intervals in November 2021, meaning that all demand in the state was met by distribution connected generators (predominantly distributed solar PV). This is expected to occur more frequently in the future, increasing the need for the transmission system to support residential customers to trade power across the National Electricity Market (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 distributed rooftop solar PV capacity will lead to periods of zero grid level demand as soon as 2023[3]** **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. distributed rooftop solar PV, household batteries, electric vehicles, hydrogen production, demand management) Explore the challenges of the increasing penetration of distributed energy resources, including intermittency/rapid changes, controllability, operation during system events and overall system stability. Consider AEMO's Engineering Framework for future investigations on operational conditions
	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	We have rolled out a limited Wide Area Monitoring Scheme (WAMS) that uses phasor monitoring units to provide enhanced, high-resolution, time-synchronised wide area system monitoring access across the SA transmission network. We plan to enhance the existing WAMS by installing further phasor measurement units at candidate sites across the SA transmission network, which have been selected in collaboration with AEMO. 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) We have developed and agreed a joint voltage control strategy that aims to optimise voltage management and investment across the transmission and distribution network to help support the delivery of safe, secure, reliable and affordable power supplies to electricity customers.

[3] *At the state-wide level, net negative South Australian operational demand was observed during several five-minute dispatch intervals in November 2021.*

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	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 March 2023. As part of Project EnergyConnect a Special Protection Scheme (SPS) 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. 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 monitor and improve local power quality (section 7.4) We have included installation of power quality management devices as a contingent project in our Revenue Proposal for the Regulatory Period 2023-2028

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	We have rolled out a limited Wide Area Monitoring Scheme (WAMS) that uses phasor monitoring units to provide enhanced, high-resolution, time-synchronised wide area system monitoring access across the SA transmission network We plan to enhance the existing WAMS by installing further phasor measurement units at candidate sites across the SA transmission network, which have been selected in collaboration with AEMO
	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 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	We have contracted with BESSs for provision of FFR services and plan to engage with emerging BESSs to meet future FFR service needs 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

We have started building Project EnergyConnect, to create a new interconnection between South Australia and New South Wales with an added connection to northwest Victoria. This new interconnector will provide 800 MW of transfer capacity between South Australia and New South Wales.

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 2022 Integrated System Plan (ISP). This project 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 have also identified future projects in line with the 2022 ISP. These include investments that would increase transfer capacity to allow for greater imports and exports of renewables between South East, Tailem Bend and Adelaide (South East SA REZ Expansions) and between Mid North and Adelaide (Mid North SA REZ Expansion). Aside from benefiting intra-regional transfer capacities, these projects would optimise interstate transfer capabilities between the Heywood interconnector, Project EnergyConnect interconnector and Murraylink interconnector.

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

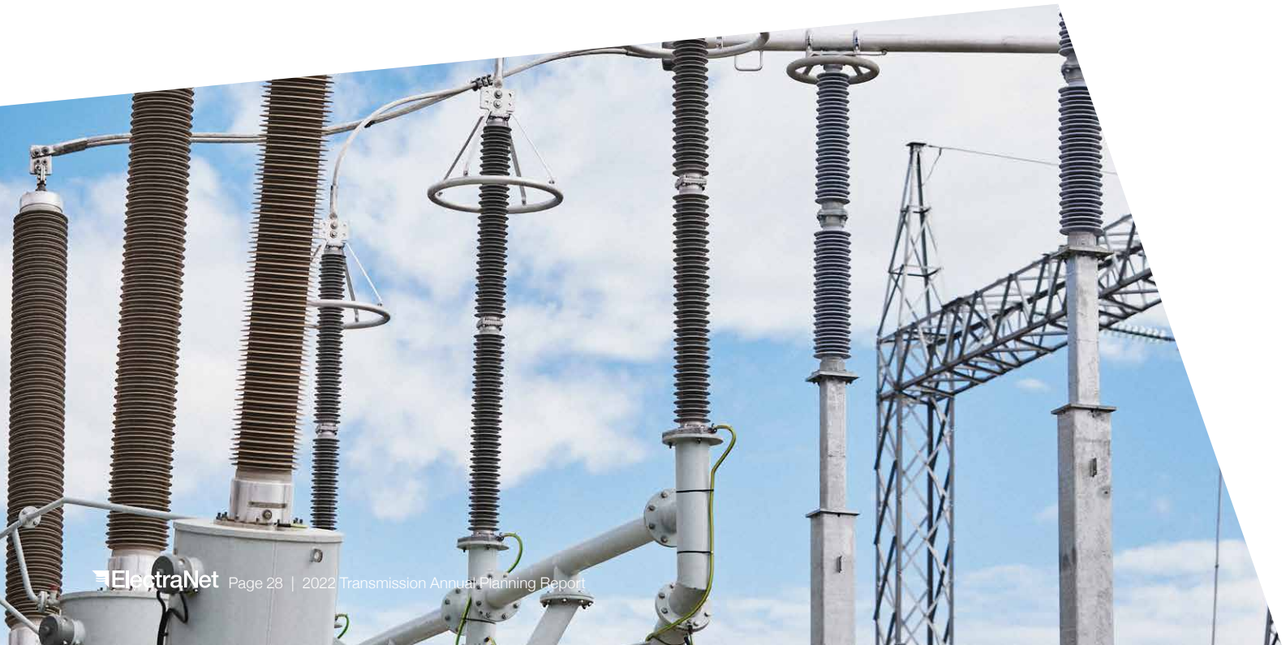
1.3.2 Managing asset condition

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 supply-side changes

The generation mix in South Australia is undergoing major changes in the medium to long-term, and we have an important role in enabling this transition. We track adoption trends and anticipate changes. We then create plans to appropriately upgrade the capability of the transmission network.

Based on projections in AEMO's 2022 ISP, significant investment in renewable generation, battery storage and other forms of dispatchable generation within South Australia is expected in the early 2030s. Distributed energy sources are likewise expected to have increased significantly in quantity by that time.

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 have indicated that generation withdrawal will occur in the early 2020s. Many of the existing dispatchable conventional generators currently have expected withdrawal dates around 2030.

We continue to investigate options to unlock the network capacity and to provide services for facilitating the connection of new renewable generation and the retirement of dispatchable conventional generation. We have developed high level scopes for projects to 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.

We will be performing preparatory activities for the South East SA Renewable Energy Zone (REZ) expansion and the Mid North SA REZ expansion, which were identified as future ISP projects in the 2022 ISP. Preparatory activities include delivery of a preliminary engineering design, easement assessment, cost estimates based on preliminary engineering design and route selection, preliminary assessment of environmental and planning approvals and stakeholder engagement.

The installation of synchronous condensers at Davenport and Robertstown in 2021 has increased system strength and 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. The synchronous condensers have also enabled South Australia's transmission network to be operated securely with only two large synchronous generator units in-service. Studies are being performed to determine system limits that would apply with only one synchronous unit in-service.

In October 2021 the Australian Energy Market Commission (AEMC) finalised a new rule that will evolve the current system strength framework. The new 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, reducing overall demand and minimising the costs associated with its supply.

We are collaborating with AEMO as they develop new rules and planning considerations to ensure the capabilities of flexible loads can be fully utilised for the community's benefit.

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. Activity suggests new connections may exceed AEMO's 2022 ISP *Step Change* scenario in terms of both speed and size.

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 and have included them as contingent projects in our Revenue Proposal for the 2024-2028 regulatory control period.

1.3.4 Inertia

South Australia has become a world leader in intermittent renewable energy generation penetration levels, and 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 and inertia.

We have now installed high-inertia synchronous condensers at Davenport and Robertstown to address system strength and synchronous inertia requirements.

In 2020 AEMO declared an inertia shortfall for South Australia. AEMO 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 entered into agreements for the provision of FFR for 2022-23. AEMO declared an increased requirement of 360 MW of FFR raise service in December 2021. ElectraNet has begun procurement of the increased requirement.

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

The increasing customer adoption of distributed energy resources (DER) is providing consumers with control over their energy costs with their own investments and an option for those seeking to reduce their carbon footprint.

As a result, historically low demand levels have been 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). This condition presents operational challenges to South Australia's transmission network.

AEMO has been working with the industry in developing an Engineering Framework[4]. This is a toolkit that defines the full range of operational, technical, and engineering requirements needed to prepare the NEM for six identified future operational conditions, including preparation for 100% instantaneous penetration of renewables. The framework seeks to facilitate an orderly transition to a secure and efficient future NEM system.

Because of South Australia's leading penetration of distributed rooftop solar PV relative to demand and with the increasing generation coming from large renewable sources, it is very likely that we will be the first state to address these challenges head-on. In South Australia we are already experiencing decreased dispatch of large synchronous generators.

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.

[4] *AEMO, aemo.com.au/en/initiatives/major-programs/engineering-framework*

In our 2024-2028 Revenue Proposal we identified a need to restore and augment the reactive reserve capability of South Australia's transmission network as minimum demand levels continue to fall, to preserve the dynamic control capability on equipment such as static var compensators 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. We have also identified a need to automate our reactive plant and the voltage control mechanisms of our transformers to manage fluctuations in the voltage profile as we experience more two directional power flows on our substations daily.

Some of the other challenges of high distributed rooftop solar PV include output variability (for example, due to cloud cover) and its impact of reducing the effectiveness of load-based emergency control schemes during the daytime.

The final report for AEMO's 2022 PSFRR was published on 26 July 2022.[5] It recommends revisions to constraints on the Heywood interconnector associated with the existing protected event for destructive wind conditions in South Australia. It also indicates AEMO's intention to explore options to forecast and manage future NEM ramping events (such as were identified in South Australia during 2021) resulting from the increasing penetration of distributed solar PV generation and transmission-connected inverter-based resources.

From 2023, the PSFRR will be replaced with a broader General Power System Risk Review (GPSRR).

The GPSRR is intended to help AEMO, Network Service Providers 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 transformation is underway. We are assessing the impact that this will have on our planning processes and priorities.

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. Committed and planned investments include:

- implement a Wide Area Protection Scheme with the use of phasor measurement units (PMUs) to real time monitor and process system parameters for event detection (section 7.3)
- enhance high resolution time synchronised wide area system monitoring by rolling out a Wide Area Monitoring Scheme (WAMS, 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.

The development of DER - as an extension of distributed rooftop solar PV - and the adoption of more advanced operating capabilities is enabling the development of Virtual Power Plants (VPPs). Over the next 10 years, VPPs have the potential to be new providers of services for both ElectraNet and SA Power Networks.

AEMO's ISP highlights that to ensure the NEM power system can operate securely with high penetration of inverter-based resources, the system operator and network service providers like ElectraNet will need to uplift their capabilities in operational systems, processes, real time monitoring and power system modelling. We are working closely with AEMO and other stakeholders to develop a roadmap for the uplift required to operate the NEM securely with 100% renewables, and are seeking to progress the systems and capability uplift required to protect the power system from disturbances in an increasingly complex operating environment.

We have installed high-inertia synchronous condensers at Davenport and Robertstown to address system strength and synchronous inertia requirements.

[5] *Available at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/psfrr/2022-final-report---power-system-frequency-risk-review.pdf?la=en.*

1.3.6 Climate Change

Bushfire risk

Climate change is expected to increase temperatures and influence rainfall patterns increasing the incidence of extreme weather such as drought. These factors are expected to combine to increase the incidence and severity of bushfires.[6]

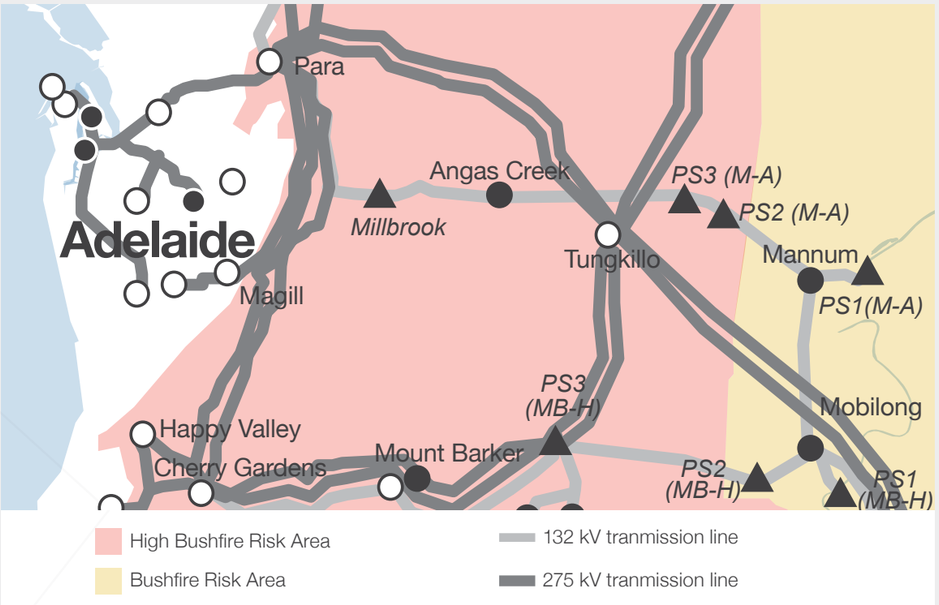
The Greater Adelaide area is responsible for the majority of South Australia's economic activity. Adelaide is surrounded by the Adelaide Hills - to the south and east - which are high bushfire risk areas. The major substations of Para, Magill, Tungkillo and Cherry Gardens are all located in this area (Figure 2). With the retirement and mothballing of gas fired generation at Torrens Island, these locations become ever more important for the supply of Adelaide.

These substations are all within 50 km of each other, covering an area of 200,000 hectares. By comparison, the NSW bushfires of 2019-20 burnt an area that covered over 17 million hectares. Individual fires in NSW, such as Hospers Mountain (Hawkesbury), Green Wattle Creek (Wollondilly) and Currowan (Shoalhaven) each burnt areas of more than 200,000 hectares.[7]

Intermittent and short duration interruptions to transmission services can occur due to the presence of smoke, meaning even small fires in the wrong location could have consequences for transmission services. Longer, more persistent outages could eventuate if fires damaged lines or substations. Such events are more likely to occur with catastrophic events.

Due to the potential impacts this might have on electricity supply to the Adelaide area during a natural disaster, this risk warrants consideration in our short-term to medium-term planning of the transmission network.

Figure 2: Bushfire risk areas and transmission network map



Coastal inundation

With South Australia's population typically situated on the coast, electrical transmission infrastructure is often quite close to the coast.

Climate change is forecast to lead to increases in sea level which may lead to coastal inundation. Regions such as the Lefevre Peninsula and Torrens Island are low lying and exposed to this risk. Other areas such as Davenport may be exposed but at lesser risk.

Sea levels are not forecast to rise quickly, however major tidal storm surges can occur at short notice. We are considering this risk in our medium-term planning of the transmission network.

Increasing temperatures

Climate change is forecast to increase global temperatures. An increase in temperature is expected to lead to derating of the transmission network. Deratings will be correlated with maximum demand conditions which are driven by high temperatures.[8]

The potential effects of higher temperatures and the risk of derating is being considered in our medium-term planning of the transmission network.

[6] Climate Change Australia, Bushfire risks for transmission, 2021
[7] Australian Parliament House, 2019-20 Australian bushfires – frequently asked questions: a quick guide, 2020
[8] Climate Change Australia, The Impact of Climate Change on Transmission Line Ratings, 2021

1.3.7 Potential drivers of load

South Australia's energy transformation are impacting not only the supply side but also influencing the connection of new loads such as emerging new industries like hydrogen production, hydrogen export, and cryptocurrency data centres. These loads would like to take advantage of South Australia's low-cost and low-emission electricity from renewable sources.

The South Australian Government has created the Hydrogen Jobs Plan[9] which will realise the construction of a world-leading hydrogen power station, electrolyser, and storage facility within the Whyalla City council in the upper north of South Australia. These facilities that are composed of 250 MW of electrolysers, 200 MW power generation and storage for 3,600 tonnes of hydrogen are expected to be operational by end of 2025.

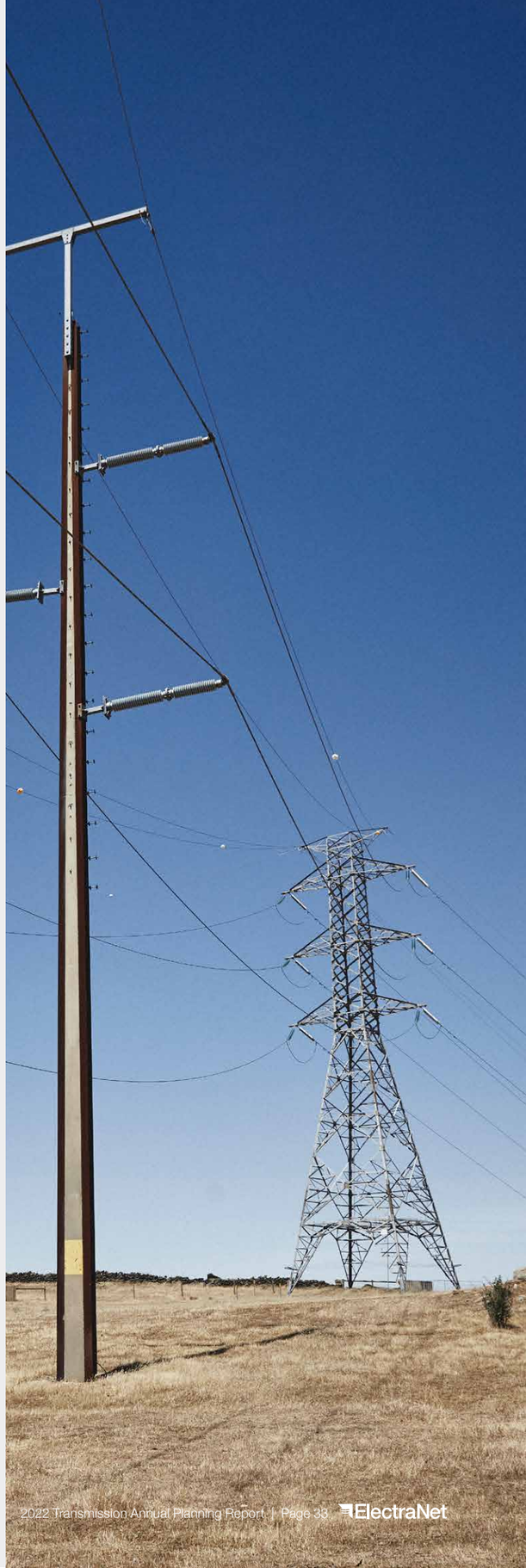
The Hydrogen Jobs Plan and hydrogen export hubs[10] are setting up South Australia for an initial development of a hydrogen industry that is faster than projected in the *Hydrogen Superpower* scenario in the 2022 ISP.

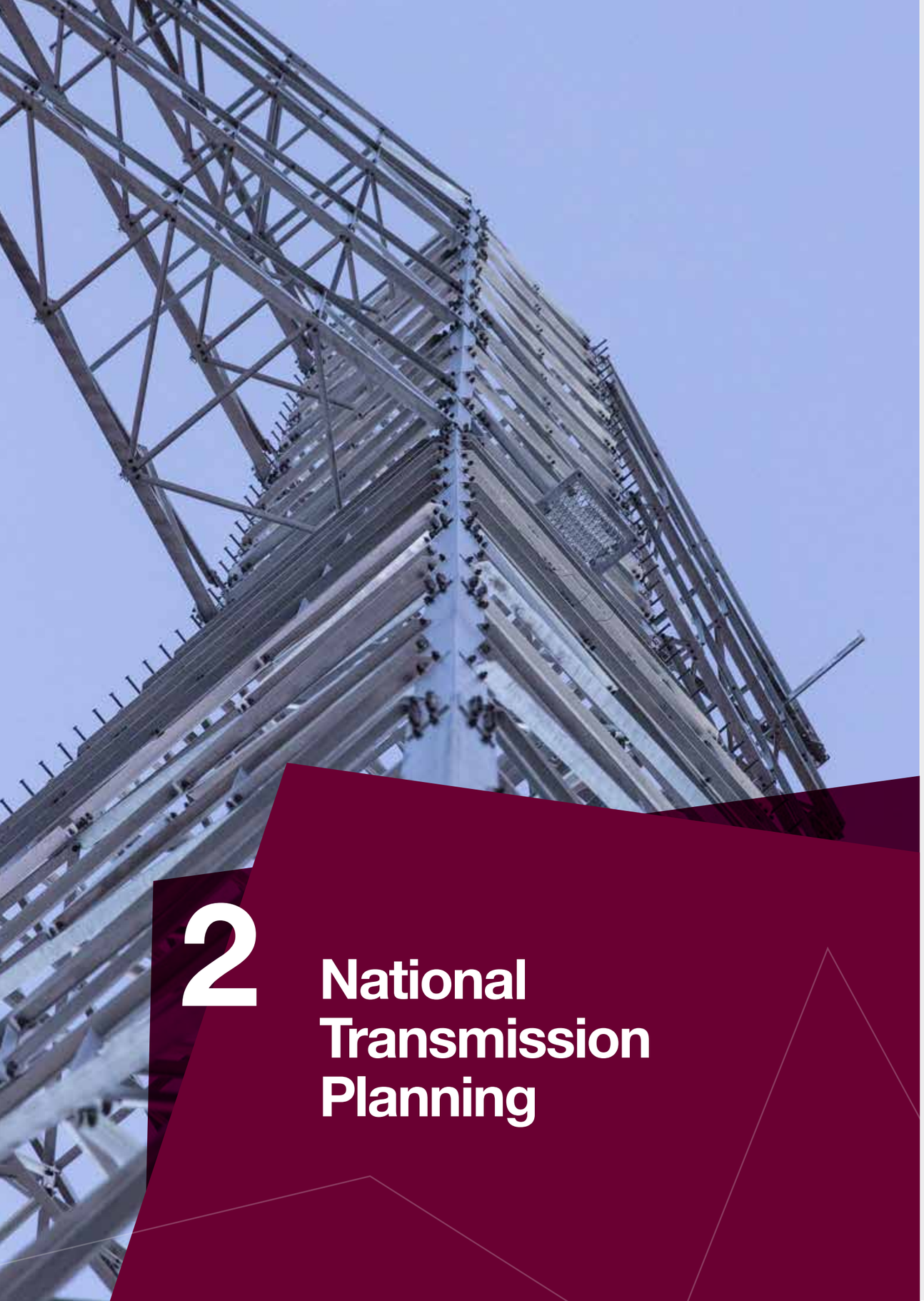
The 2022 ISP identified the Step Change scenario as the most likely future based on extensive consultation with the industry. This scenario will see consumers rely on electricity for heating and transport (i.e. electric vehicles). Under this scenario we will experience a steady increase in the maximum demand for the next ten years as we start to see the increased electrification of the consumer household and transport services.

We are considering these scenarios in our studies and are creating plans to develop the transmission infrastructure and services to support them.

> **Climate change is expected to increase temperatures and influence rainfall patterns increasing the incidence of extreme weather such as drought. These factors are expected to combine to increase the incidence and severity of bushfires.**

[9] SA Government, Hydrogen Jobs Plan
[10] SA Government, hydrogen export hubs





2 National Transmission Planning

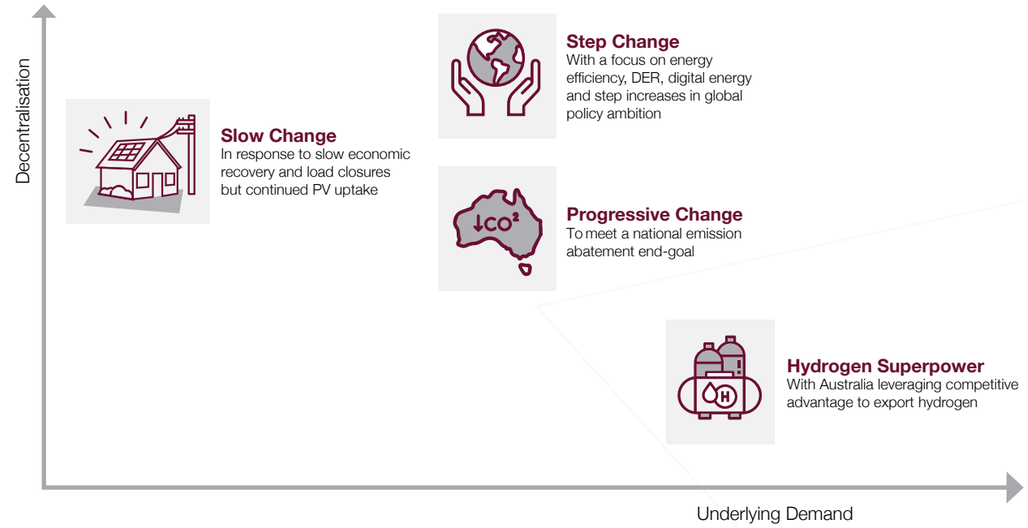
2.1 Integrated System Plan

AEMO's 2022 Integrated System Plan (ISP)[11] recognises the once-in-a-century transformation that is currently underway in how electricity is generated and consumed in the National Electricity Market (NEM).

The ISP identifies an Optimal Development Path for development of the NEM, which will see fossil fuelled legacy assets replaced with low-cost renewables, energy storage and other new forms of firming capacity, and reconfigure the grid to support two-way energy flow.

The 2022 ISP considered four scenarios, each reflecting a range of assumptions regarding the pace of energy transformation on the path to reach net zero by 2050 (Figure 3). In each scenario, the scale of electricity demand is influenced by the extent to which other sectors electrify (for example, the transportation sector through the uptake of electric vehicles). Decentralisation is the extent to which business and household consumers manage their own electricity generation, storage or services, rather than just draw power from the gird. In the case of the *Hydrogen Superpower* scenario, this decentralisation is forecast to be swamped by the scale of electricity demand needed for a hydrogen export industry.

Figure 3: AEMO's 2022 ISP planning scenarios



Source: AEMO's 2022 ISP, Figure 6

During 2021, AEMO twice convened a panel of Australian energy market experts, with an intervening round of public consultation, to conclude that Step Change is considered the most likely scenario to play out.

We utilise AEMO's ISP scenarios for our planning, with the appropriate application of scenarios varying according to the need:

- In annual planning, we primarily consider the Step Change scenario
- For a RIT-T that is triggered by AEMO's ISP, we will consider and apply scenarios as directed by AEMO
- For other RIT-Ts, we will assess the appropriate treatment of scenarios on a case-by-case basis – for example, *Hydrogen Superpower* is a key scenario to consider in RIT-Ts where option value is a potentially significant market benefit.

[11] *AEMO, 2022 Integrated System Plan*

2.1.1 South Australian projects in the 2022 ISP

The 2022 ISP identified four network investments in South Australia as part of the Optimal Development Path.

These are:

- Two committed projects – Eyre Peninsula Link and Project EnergyConnect
- Two future ISP projects – South East South Australian REZ Expansion and Mid North South Australian REZ Expansion.

Eyre Peninsula Link

This project is replacing an ageing 132 kV single-circuit line from Cultana to Yadnarie and from Yadnarie to Port Lincoln with a higher thermal capacity new double-circuit line. We completed the RIT-T and gained regulatory approval from the AER in September 2020. This is a committed project, currently on track for completion by January 2023.

Project EnergyConnect

Project EnergyConnect is a new 330 kV interconnector between South Australia and New South Wales. The interconnector will run from Robertstown in South Australia to Wagga Wagga in New South Wales, via the most north section of the transmission network in Victoria. It traverses between east and west, linking the REZs of Riverland, Murray River, and South West New South Wales, providing additional hosting capacity in each of these REZs.

ElectraNet and TransGrid gained regulatory approval from the Australian Energy Regulator (AER) in May 2021. Project EnergyConnect remains on track to be delivered in two stages:

- The completion of construction from Robertstown in South Australia to Buronga in NSW, energisation and commissioning in late 2023, with inter-network testing and release of initial transfer capability up to 150 MW over the following 6 months
- The completion of the second section from Buronga to Wagga Wagga in NSW, energisation and commissioning in late 2024, with inter-network testing and release of transfer capacity up to 800 MW over 12-18 months, subject to market demand

Opportunities to accelerate inter-network testing timeframes are under active consideration for this project of national significance.

South East SA REZ Expansion

The South East SA REZ lies on the major 275 kV route of the South Australia – Victoria Heywood interconnector. The REZ has moderate to good quality wind resources as evidenced by the high proportion of wind generation (over 300 MW) in or near the South East border with Victoria.

Stage 1 of the South East SA REZ expansion is required in the mid to late 2020s in the *Hydrogen Superpower* scenario and the *Step Change* scenario to facilitate the connection of generation within this REZ. In 2022-23 we are undertaking preparatory activities for stage 1 of the South East South Australia REZ Expansion project, to inform development of AEMO's 2024 ISP.

Mid North SA REZ Expansion

The Mid North SA REZ has moderate quality wind and solar resources. There are several major wind farms in service in this REZ, totalling over 1,300 MW installed capacity.

Stage 1 of the Mid North SA REZ expansion is required in the late 2020s in the *Hydrogen Superpower* scenario, and early 2030s in the *Step Change* scenario to facilitate the connection of generation within these REZs. In 2022-23 we are undertaking preparatory activities taken for stage 1 of the Mid North SA REZ Expansion project, to inform development of AEMO's 2024 ISP.

2.1.2 Overview of all candidate REZs in South Australia

The 2022 ISP identifies nine candidate Renewable Energy Zones (REZs) in South Australia, which are consistent with the REZs identified in the 2020 ISP. We have identified potential network investments to release capacity in each of the candidate REZs.

The 2022 ISP indicated that under most scenarios, most of these South Australian REZs are not forecast to require development within the next 20 years, except for the developments already discussed. In contrast, the *Hydrogen Superpower* scenario would require significant development of many of the candidate REZs.

Project EnergyConnect is a new 330 kV interconnector between South Australia and New South Wales.

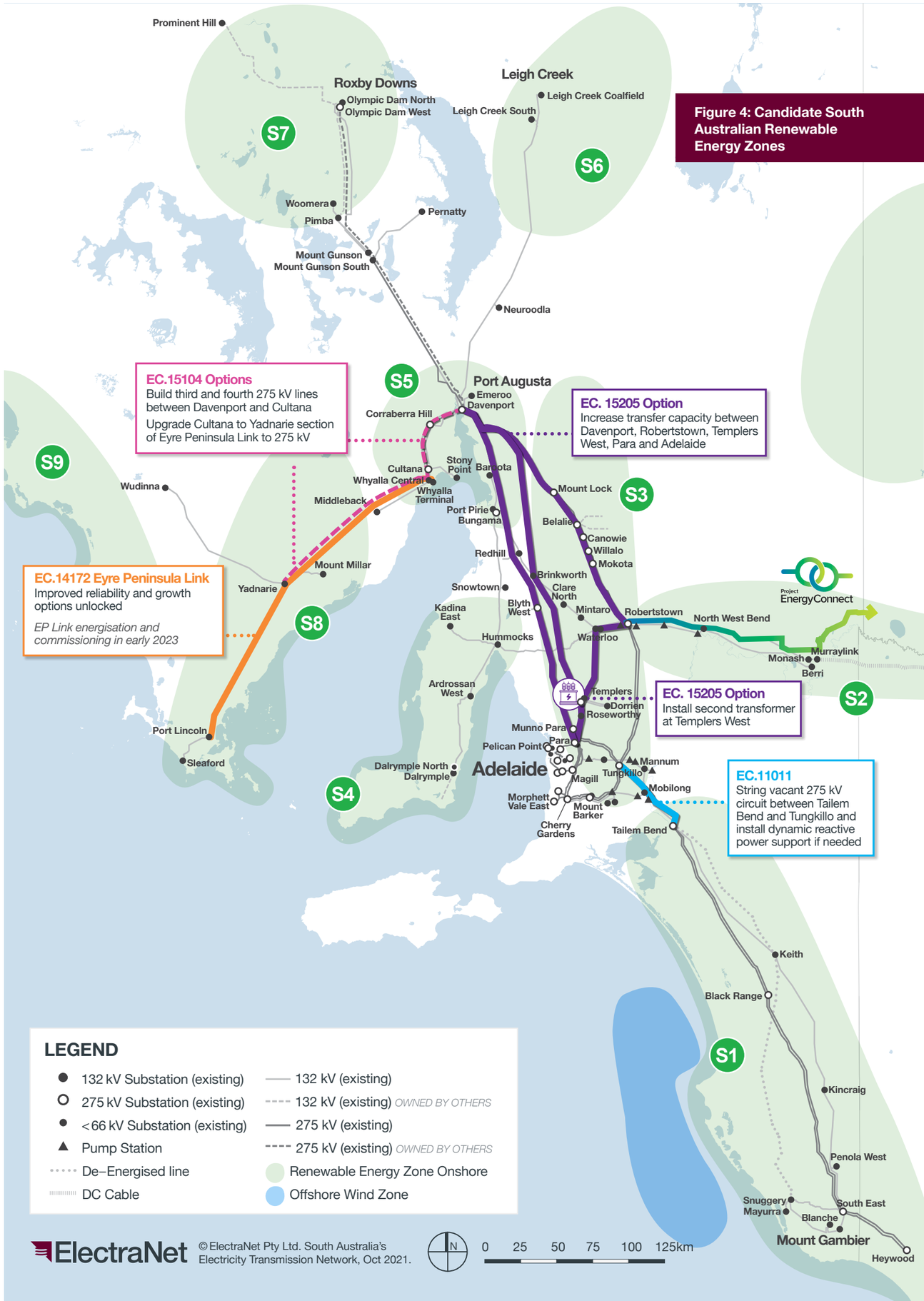


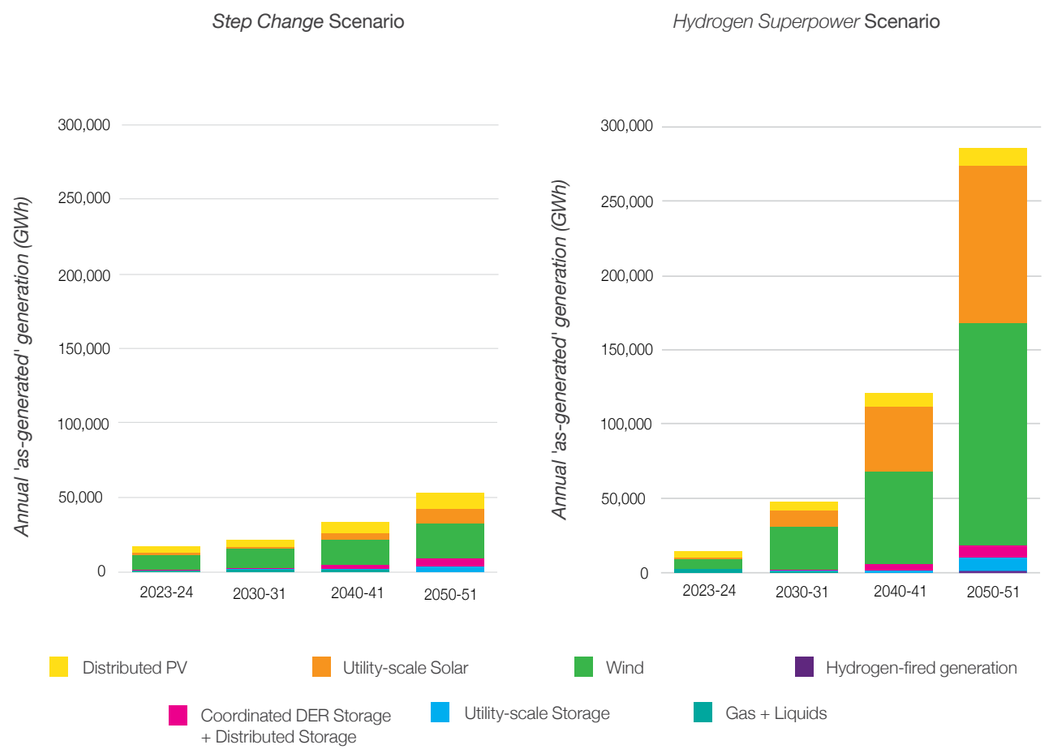
Table 1: Potential network investments to release capacity in South Australian Renewable Energy Zones

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. A project to deliver this increased capacity (EC.11011) is not included in our Revenue Proposal for the 2024-2028 regulatory control period, but will be triggered as a contingent project if AEMO declares it in a future ISP to be an actionable project (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. A project to deliver this increased capacity (EC.15205) is not included in our Revenue Proposal for the 2024-2028 regulatory control period but will be triggered as a contingent project if AEMO declares it in a future ISP to be an actionable project (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.15104) 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 have proposed 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 have proposed 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

2.1.3 Generation development in the *Hydrogen Superpower* scenario

The 2022 ISP's *Hydrogen Superpower* scenario forecasts a level of renewable generation development that far exceeds the forecast of development in other scenarios. It forecasts that by 2050, the total capacity of installed generation in South Australia will increase more than 20-fold (Figure 5).

Figure 5: *Step Change* and *Hydrogen Superpower* scenario generation modelling outcomes comparison



The South Australian government's Hydrogen Jobs Plan targets the construction of a world-leading hydrogen power station, electrolyser and storage facility within the Whyalla City Council by the end of 2025. This is planned to include:

- 250 MW (electrical demand) of electrolysers
- 200 MW of power generation, powered by hydrogen produced by the electrolysers
- Hydrogen storage for 3,600 tonnes of hydrogen, or the equivalent of two months' of hydrogen consumption for power generation.[12]

Further potential hydrogen developments in South Australia include the Port Pirie Green Hydrogen Project. Starting at 20 tonnes per day of green hydrogen for export in the form of green ammonia, the full-scale plant would produce 100 tonnes per day of green hydrogen from a 440 MW electrolyser to meet both export and domestic supply needs. A Front End Engineering Design study, jointly funded by Trafigura and the Government of South Australian, is currently underway with a final investment decision expected by the end of 2022.[13]

Given these and other potential hydrogen initiatives, we anticipate that developments in South Australia could track between the *Step Change* and *Hydrogen Superpower* scenarios.

[12] *Hydrogen Jobs Plan, https://www.energymining.sa.gov.au/industry/modern-energy/hydrogen-in-south-australia/hydrogen-jobs-plan, retrieved 21 September 2022.*
[13] *Nyrstar Port Pirie, https://www.nyrstar.com/operations/metals-processing/nyrstar-port-pirie, retrieved 21 September 2022.*

We have compared the amount of renewable generation forecast to be developed in each REZ by 2050 (Table 2). This shows that if the *Hydrogen Superpower* scenario eventuates, the scope of development to unlock the Mid North SA, Leigh Creek, Eastern Eyre Peninsula and Western Eyre Peninsula REZs would need to far exceed the scope required in other scenarios, equivalent to a twenty-fold increase from today's network's capability.

In addition, it is likely that an additional very large increase of interconnection capability between South Australia and the rest of the NEM would be needed to assist generation and demand balancing across the NEM.

Demand forecasts for the *Hydrogen Superpower* scenario are discussed in section 3.3.2. The required scope of the required REZ and future interconnector developments will depend greatly on the location of the new load centres to which the new generation will need access.

Table 2: Comparison by REZ of installed generation capacity in 2050

REZ	Generation type	*Step Change*	*Hydrogen Superpower*	Comment
S1 South East SA	**Solar**	0 MW	100 MW	Significant development of wind generation is forecast in the South East SA REZ for all scenarios
	Wind	2,540 MW	3,200 MW	
S2 Riverland	**Solar**	2,050 MW	4,000 MW	Forecast development of solar PV generation in the Riverland REZ for *Hydrogen Superpower* is about double the forecast for *Step Change*
	Wind	0 MW	0 MW	
S3 Mid North SA	**Solar**	0 MW	1,300 MW	Forecast development of wind in the Mid North SA REZ for *Hydrogen Superpower* far exceeds the existing generation capacity of the South Australian grid This would require an augmentation solution with much greater capacity than has been yet contemplated, with the scope depending on the location of the new load centres to which the new generation will need access
	Wind	3,500 MW	28,900 MW	
S4 Yorke Peninsula	**Solar**	0 MW	0 MW	Significant development of wind generation is forecast in *Hydrogen Superpower*
	Wind	100 MW	1,400 MW	
S5 Northern SA	**Solar**	2,450 MW	2,900 MW	Significant development of solar PV generation is forecast for all scenarios
	Wind	0 MW	0 MW	
S6 Leigh Creek	**Solar**	1,950 MW	41,800 MW	Forecast development of solar PV and wind generation in the Leigh Creek REZ for *Hydrogen Superpower* far exceeds the existing generation capacity of the South Australian grid This would require an augmentation solution with much greater capacity than has been yet contemplated, with the scope depending on the location of the new load centres to which the new generation will need access
	Wind	1,950 MW	17,200 MW	
S7 Roxby Downs	**Solar**	700 MW	3,400 MW	Forecast development of solar PV generation in the Roxby Downs REZ for *Hydrogen Superpower* is about five times the forecast in Step Change
	Wind	0 MW	0 MW	
S8 Eastern Eyre Peninsula	**Solar**	0 MW	5,000 MW	Forecast development of solar PV and wind in the Eastern Eyre Peninsula for *Hydrogen Superpower* is approximately equivalent to the existing generation capacity of the South Australian grid This would require an augmentation solution with much greater capacity than has been yet contemplated for the Eastern Eyre Peninsula, with the scope depending on the location of the new load centres to which the new generation will need access
	Wind	250 MW	2,300 MW	
S9 Western Eyre Peninsula	**Solar**	0 MW	4,000 MW	Forecast development of solar PV and wind generation in the Western Eyre Peninsula REZ for *Hydrogen Superpower* is approximately equivalent to the existing generation capacity of the South Australian grid This would require an augmentation solution with much greater capacity than has been yet contemplated for the Eyre Peninsula, with the scope depending on the location of the new load centres to which the new generation will need access
	Wind	0 MW	1,750 MW	
O6 South East SA Coast	**Offshore wind**	0 MW	0 MW	No development of offshore wind generation in South Australia is forecast in any scenario

2.2 2021 System Security Reports

AEMO published the 2021 System Security Reports in December 2021 and published an update in May 2022.[14] In the System Security Reports, AEMO identifies system security needs across the NEM for the coming five-year period in the areas of system strength, inertia and Network Support and Control Ancillary Services (NSCAS).

2.2.1 System strength

AEMO's review of system strength needs across the NEM identified that there is no system strength shortfall in South Australia, given the four synchronous condensers that we installed during 2021 (two at Davenport and two at Robertstown).

2.2.2 Inertia

AEMO's review of inertia needs across the NEM confirmed the shortfall that was declared in 2020, for 200 MW of fast frequency response or equivalent inertia support activities, until 30 June 2023. We have contracted with third parties for the provision of the required services.

AEMO also declared a new shortfall, equivalent to 360 MW of fast frequency response or equivalent inertia support activities, from 1 July 2023 until the expected completion of Project EnergyConnect. We are engaging the market for provision of the required services.

2.2.3 NSCAS

AEMO declared a 40 Mvar reactive power absorption gap that will exist in South Australia when the requirement for the minimum number of synchronous generating units reduces from two to zero.

This need will be more than fully met by our planned installation of a suite of switched 275 kV reactors or equivalent services as part of EC.11645 Transmission Network Voltage Control (section 7.4).

2.3 Power System Frequency Risk Review

AEMO published its final report for the 2022 Power System Frequency Risk Review (PSFRR) in July 2022. The purpose of the PSFRR is to review non-credible contingency events that have the potential to involve uncontrolled increases or decreases in frequency (alone or on combination) leading to cascading outages, or major supply disruptions.

Where AEMO identifies a need for additional or alternative measures to manage the risk of such events over a five-year outlook period, the PSFRR assesses options considered technically and economically feasible.

The 2022 PSFRR includes updates on key findings and recommendations from the 2020 PSFRR.

Consistent with the 2022 ISP, the 2022 PSFRR acknowledges that the NEM is supporting a once-in-a-century transformation in the way society considers and consumes energy.

The PSFRR explores the risks and consequences of non-credible contingency events and considers how these risks are forecast to evolve over a five-year planning horizon, taking into account potential changes in power system operation over that period.

[14] *Available at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.*

2.3.1 Recommendations and findings relating to South Australia

AEMO identified that further work is required to mitigate risks associated with reduced effectiveness of under frequency load shedding (UFLS) schemes reported in the 2020 PSFRR. AEMO recommended that Network Service Providers (NSPs) regularly audit the availability of effective UFLS scheme considering the impact of distributed solar PV in their respective networks. The results should be regularly provided to AEMO for inclusion in risk assessments, UFLS reviews and planning studies.

AEMO also advised NSPs to immediately seek to identify and implement measures to restore emergency under-frequency response as close as possible to 60% of underlying load. Where this is not feasible, AEMO will collaborate with NSPs to develop an approach that identifies a level of emergency under-frequency response that is achievable, while delivering a significant reduction in power system security risks.

AEMO recommended that NSPs investigate measures to remediate the impacts of 'reverse' UFLS operation due to negative power flow on UFLS circuits and investigate arrangements to measure UFLS load availability in real time to inform power system operation and planning studies.

There is presently only one protected event declared by the Reliability Panel, being "the loss of multiple transmission elements causing generation disconnection in the South Australia region during periods where destructive wind conditions are forecast by the Bureau of Meteorology"[15]. This protected event is currently managed as follows:

- AEMO imposes a 250 MW South Australia import limit on the Heywood interconnector during forecast destructive wind conditions in South Australia
- An emergency frequency control schemes (EFCS) called the system integrity protection scheme (SIPS) is in place in South Australia to lower the risk of islanding due to trip of up to 500 MW of South Australian generation while South Australia is importing power.

AEMO reviewed the protected event and considered the impact of two committed upgrades:

- Upgrade of SIPS to a more effective Wide Area Protection Scheme (WAPS)
- Project EnergyConnect (PEC) Stage 1.

AEMO found that:

- Until PEC Stage 1 is delivered, AEMO considers it will be necessary to retain the 250 MW South Australian import limit on the Heywood interconnector during destructive wind conditions
- As part of the delivery of PEC Stage 1, AEMO recommended that:
  - The WAPS EFCS is modified to account for the change in network topology, acknowledging that ElectraNet is already progressing this
  - The existing 250 MW Heywood interconnector import limit is replaced by a 430 MW Heywood interconnector import and a 70 MW PEC stage 1 import limit during destructive wind conditions (PEC Stage 1's import limit under normal conditions is expected to be 150 MW)

AEMO will consider whether the existing protected event could be managed under the new NER reclassification framework (from March 2023)[16] and, if so, determine the applicable reclassification criteria and recommend revocation of the protected event.

AEMO identified that due to the penetration of distributed solar PV and transmission-connected inverter-based resources (IBR), South Australia is becoming more susceptible to large generation ramping events. Through analysis, AEMO identified ramping events in 2021 where the combined distributed solar PV and IBR generator output reduced by over 1,750 MW over 2.5 hours. AEMO is analysing historical ramping events to understand ramping risks and how changes in synchronous generator dispatch requirements could impact AEMO's ability to manage future ramping events. After its review is complete, AEMO plans to explore options to forecast and manage future NEM ramping events.

2.4 General Power System Risk Review

In 2023 AEMO will undertake the first General Power System Risk Review (GPSRR), which replaces the 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.

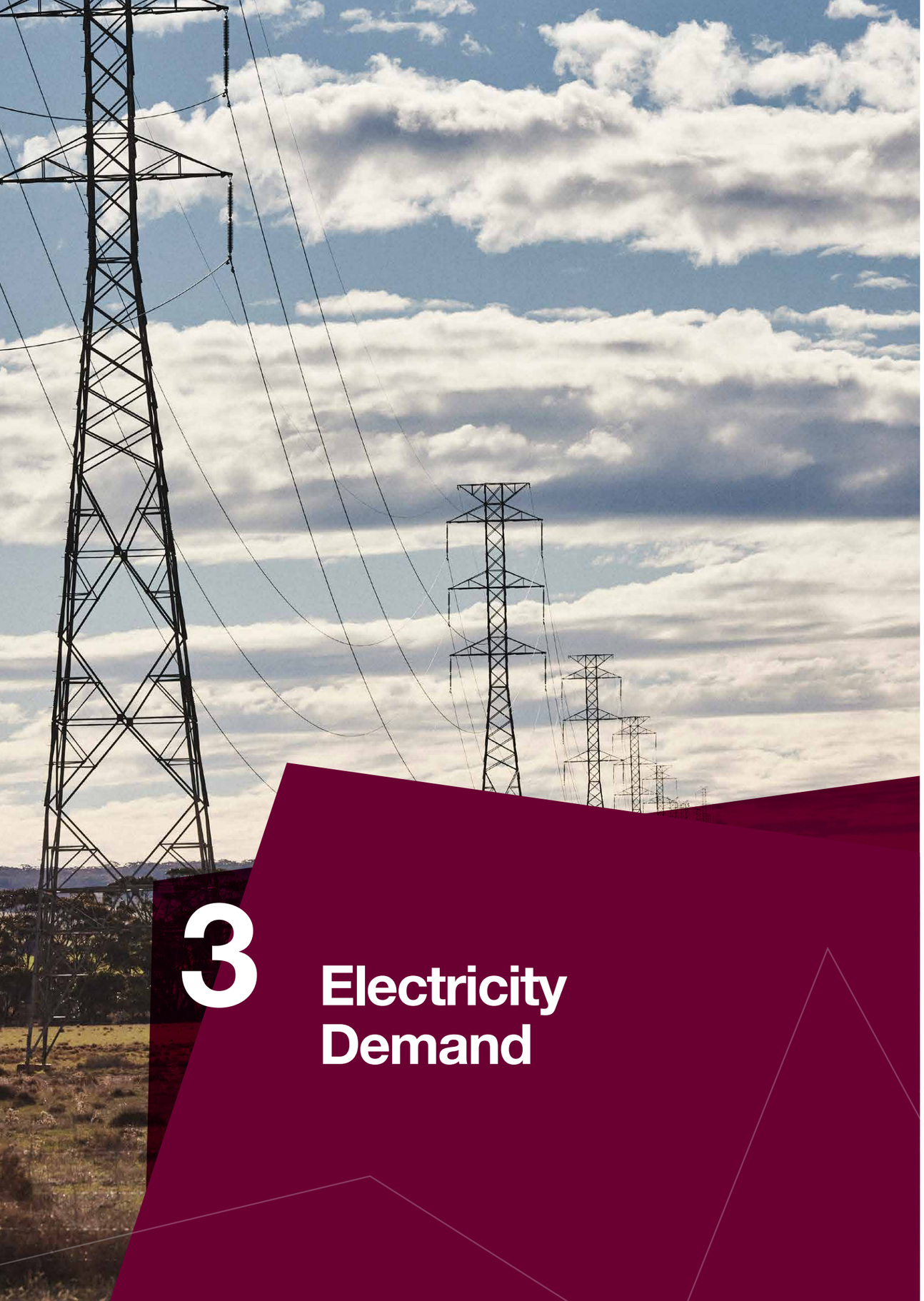
The GPSRR will be completed annually and will have a broader scope to explore a wider range of risks that could have adverse impacts on the power system. It will require AEMO to work in collaboration with NSPs to identify and assess risks to power system security that it expects would be likely to lead 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.

[15] Reliability Panel AEMC, Final Report AEMO Request for a Protected Event Declaration, 20 June 2019, p22, at https://www.aemc.gov.au/sites/default/files/2019-06/Final%20determination%20-%20AEMO%20request%20for%20declaration%20of%20protected%20event.pdf.

[16] National Electricity Amendment (Enhancing operational resilience in relation to indistinct events) Rule 2022 No. 1



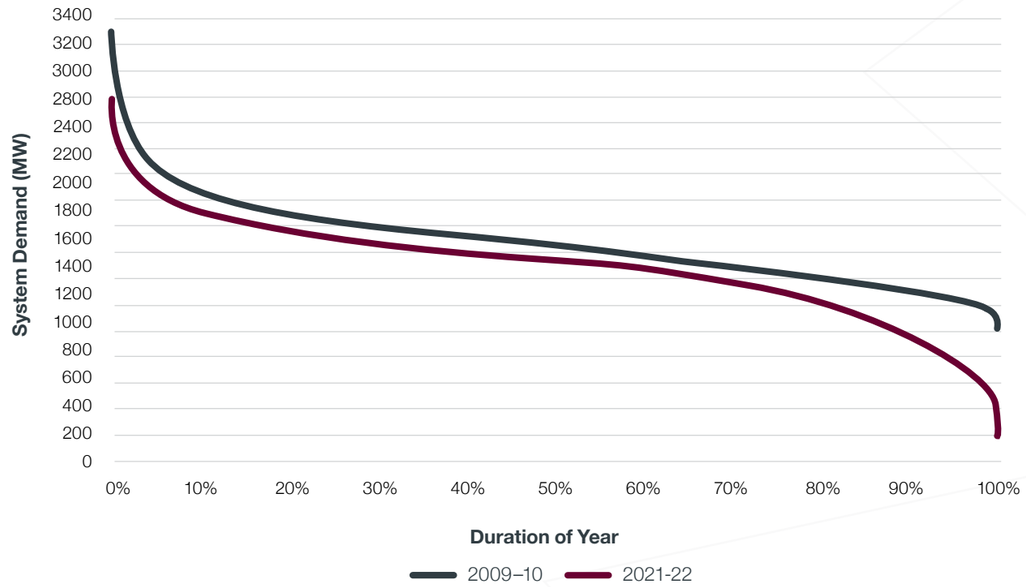
3 Electricity Demand

3.1 South Australian electricity demand

The South Australian demand profile is very 'peaky' in nature with relatively low energy content (Figure 6). 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 distributed 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 declined markedly in the period 2009-10 to 2021-22. We expect that the continuing uptake of distributed solar PV will produce even lower minimum demands.

Figure 6: South Australian system wide load duration curves for 2009-10 and 2021-22



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. Weather conditions during summer 2021-22 lacked the heatwave characteristics that typically drive very high demand levels.

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' 2021 Distribution Annual Planning Report[17]. 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 September 2021. Details of the September 2021 connection point forecasts can be found on ElectraNet's Transmission Annual Planning Report webpage.[18]

In August 2022, AEMO produced and published forecasts of energy, maximum demand and minimum demand for South Australia to support the 2022 Electricity Statement of Opportunities (ESOO).[19] 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.

ElectraNet compares its forecasts (as published on the Transmission Annual Planning Report webpage)[20] against AEMO's forecasts. At an aggregate level, ElectraNet's connection point forecasts are both reconciled to AEMO's State-level forecast from the 2022 ESOO during their development. Thus, the connection point forecasts inherently reconcile to one another.

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

[17] Available from SA Power Networks, www.sapowernetworks.com.au/industry/annual-network-plans/

[18] Available from ElectraNet, https://www.electranet.com.au/what-we-do/network/regulated-network-reports-and-studies/

[19] Available from AEMO, https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo

[20] Available from ElectraNet, https://www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/

3.3 Demand forecasts

There is no 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 2021 Transmission Annual Planning Report. We will update our plans for individual connection points in late 2022 and early 2023, based on the new connection point forecasts that we received from SA Power Networks in October 2022 and are in the process of reviewing and agreeing to.

AEMO makes state-wide demand forecasts for South Australia available on its Forecasting Data Portal.[21]

The most recent update to AEMO's South Australian state-wide forecasts was published in August 2022, alongside AEMO's 2022 ESOO.

We have compared AEMO's August 2022 ESOO central/step change forecasts for South Australian maximum and minimum demand to the 2021 ESOO forecasts that formed the basis of the plans presented in the 2021 Transmission Annual Planning Report, along with the previous five years and current year of actual maximum, average and minimum demands (below).

The 2022 ESOO forecast maximum demand and average demands indicate an increase for the next 10 years as compared with the 2021 ESOO. The maximum demand shows an increased rate of increase from 2022-23 and average demand appears to be increasing towards levels last seen in 2011-12. The rate of decline in the 2022 ESOO minimum demand appears to be similar to the 2021 ESOO; however, the 2022 ESOO minimum demand forecast levels are declining from a slightly higher base than in the 2021 ESOO.

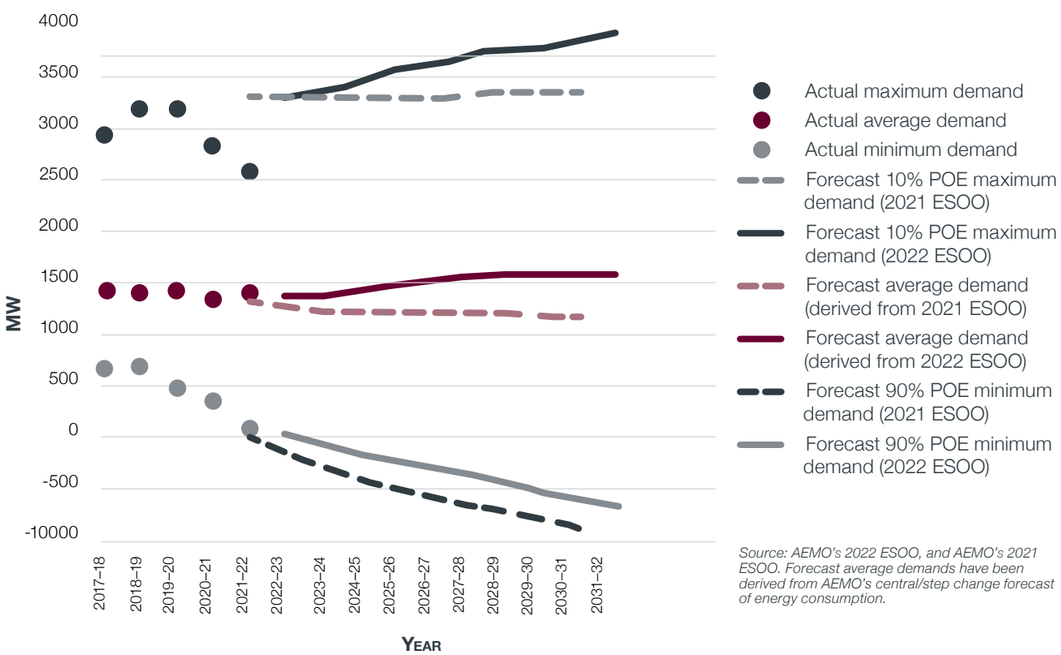
3.3.1 Potential key drivers of demand

The figure below shows maximum demands are forecast to increase 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 the Hydrogen Jobs Plan and other large hydrogen hubs in accordance with the Government of South Australia's hydrogen strategy
- The widespread adoption of electric vehicles or the electrification of appliances or sectors that currently utilise other fuel sources
- The potential connections of cryptocurrency data centres.

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

Figure 7: AEMO's 2022 ESOO Central/Step Change and 2021 ESOO Central forecasts



Source: AEMO's 2022 ESOO, and AEMO's 2021 ESOO. Forecast average demands have been derived from AEMO's central/step change forecast of energy consumption.

[21] *Accessible at http://forecasting.aemo.com.au/*

3.3.2 Demand forecasts in the *Hydrogen Superpower* scenario

Decentralisation is affecting the shape of demand and the complexity of the market. Energy on the grid is forecast to increase dramatically as electrification will more than offset distributed solar PV.

Maximum demand forecasts published with AEMO's 2022 ESOO show that in the *Hydrogen Superpower* scenario, which exclude demand explicitly related to hydrogen, maximum demands are expected to grow at a slightly greater rate than for the *Central/Step Change* scenario (Figure 8). However, a comparison of total consumption forecasts that includes consumption explicitly related to hydrogen shows that demand growth in the *Hydrogen Superpower* scenario far exceeds growth in the *Central* scenario.

Figure 8: Comparison of 2022 ESOO *Central* and *Hydrogen Superpower* maximum demand forecasts

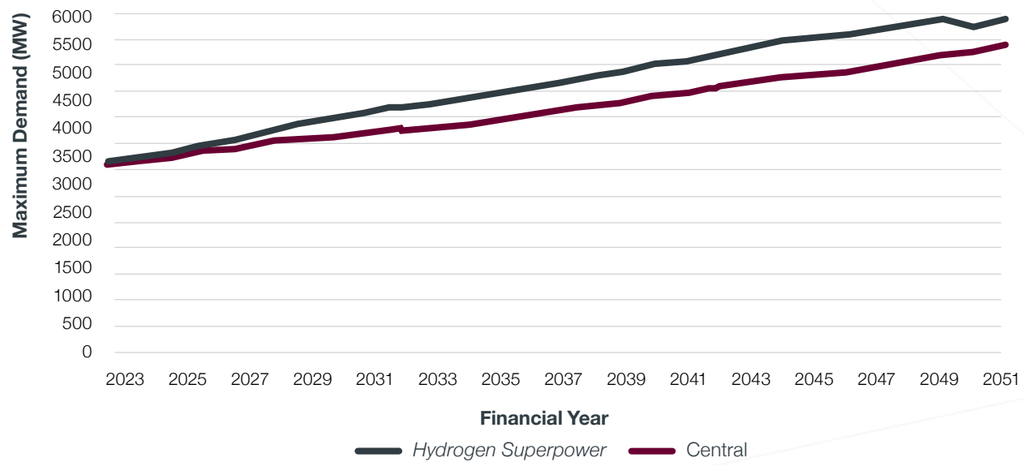
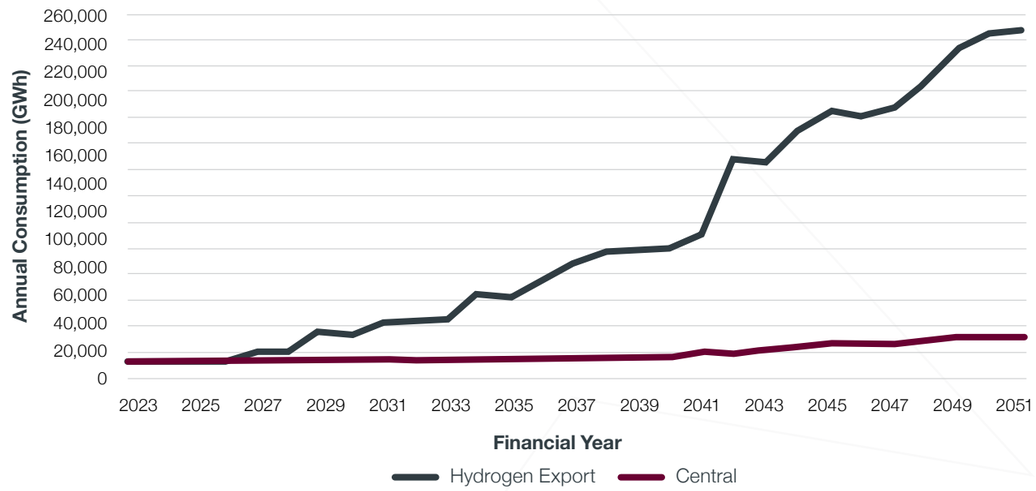


Figure 9: Comparison of 2022 ESOO *Central* and *Hydrogen Superpower* consumption forecasts



The extent of network expansion required to support the demand growth indicated in the *Hydrogen Superpower* scenario will depend very closely on where major hydrogen industry developments occur. Network expansion to support a large-scale hydrogen industry will be most efficient if coordinated to ensure that major demand centres are developed near major generation centres (e.g. REZs).

We outline potential network expansion projects to support the scale of generation and demand centre development indicated by the *Hydrogen Superpower* scenario in section 4.4.

3.4 Performance of 2021 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).

The recorded daily maximum temperatures were, on average, roughly in line with long-term trends; however, the maximum recorded temperature in each month was well below the historical extremes. The highest recorded temperature at the Bureau of Meteorology's official Adelaide city site at West Terrace was 40.3 °C on Tuesday 11 January (Table 3).

Table 3: 2021-22 Summer temperature data compared with long term trends

	November		December		January		February		March	
	Long-term trend	2021-22	Long-term trend	2021-22	Long-term trend	2021-22	Long-term trend	2021-22	Long-term trend	2021-22
Max temp (°C)	42.7	34.1	45.2	39.3	46.6	40.3	43.4	35.5	41.8	35.3
Date of max temp	30-Nov 1962	2-Nov 2021	19-Dec 2019	31-Dec 2021	24-Jan 2019	11-Jan 2022	1-Feb 1912	14-Feb 2022	3-Mar 1942	14-Mar 2022
Average max temp (°C)	24.5	23.4	26.9	27.3	28.6	29.1	28.5	28.0	26.0	27.3
Days[22]>30°C	6.1	4	9.1	6	11.7	13	10.7	10	7	7
Days[17] >35°C	1.6	0	3.8	3	5.5	4	4.4	1	1.6	1
Days[17] >40°C	0.1	0	0.6	0	1.1	1	0.6	0	0.1	0
Difference between 2020-21 average max temp and long-term trend	1.2		0.4		0.5		0.5		1.3	

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

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

[22] Mean days for long term trend data, actual days for 2021-22 data

3.4.2 State-wide demand review

State-wide demand during 2021-22 reached a maximum of 2,624 MW on Tuesday 11 January 2022. This was the only day on which demand exceeded 2,500 MW during the 2021-22 summer.

Table 4: Highest demand days in summer 2021-22

Date	Maximum demand (MW)[23]	Maximum temperature (°C)	Temperature demand index (°C)
Tuesday 11 January 2022	2,624	40	36.5

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 2021-22 summer, consistent with the subdued maximum demand levels that were recorded during the 2021-22 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).

Minimum demands were below 250 MW on 5 days between 1 October 2021 and 30 September 2022 (Table 5).

Table 5: Lowest demand days from 1 October 2021 to 30 September 2022

Date	Minimum demand (MW)[23]	Maximum temperature (°C)	Preceding overnight minimum temperature (°C)	Preceding day maximum temperature (°C)
Sunday 21 November 2021	111	22.3	11	27.1
Saturday 19 February 2022	241	24.1	12.8	21.9
Sunday 31 October 2021	244	23.3	7.4	27.6
Monday 27 December 2021	245	24.1	12	28.1
Saturday 27 November 2021	248	24.6	13.4	26.5

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.

[23] 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 PV, gas tri-generation, very small wind farms. Source: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/aggregated-data

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 2021-22, there were no connection points that recorded maximum demands that exceeded their forecast 10% POE maximum demand between 1 December 2021 and 31 March 2022.

Three of 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 17 medium connection points failed to reach 85% of their 10% POE forecast. The 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 September 2021 connection point forecasts are available in the connection point information published on our Transmission Annual Planning Report webpage.[25]

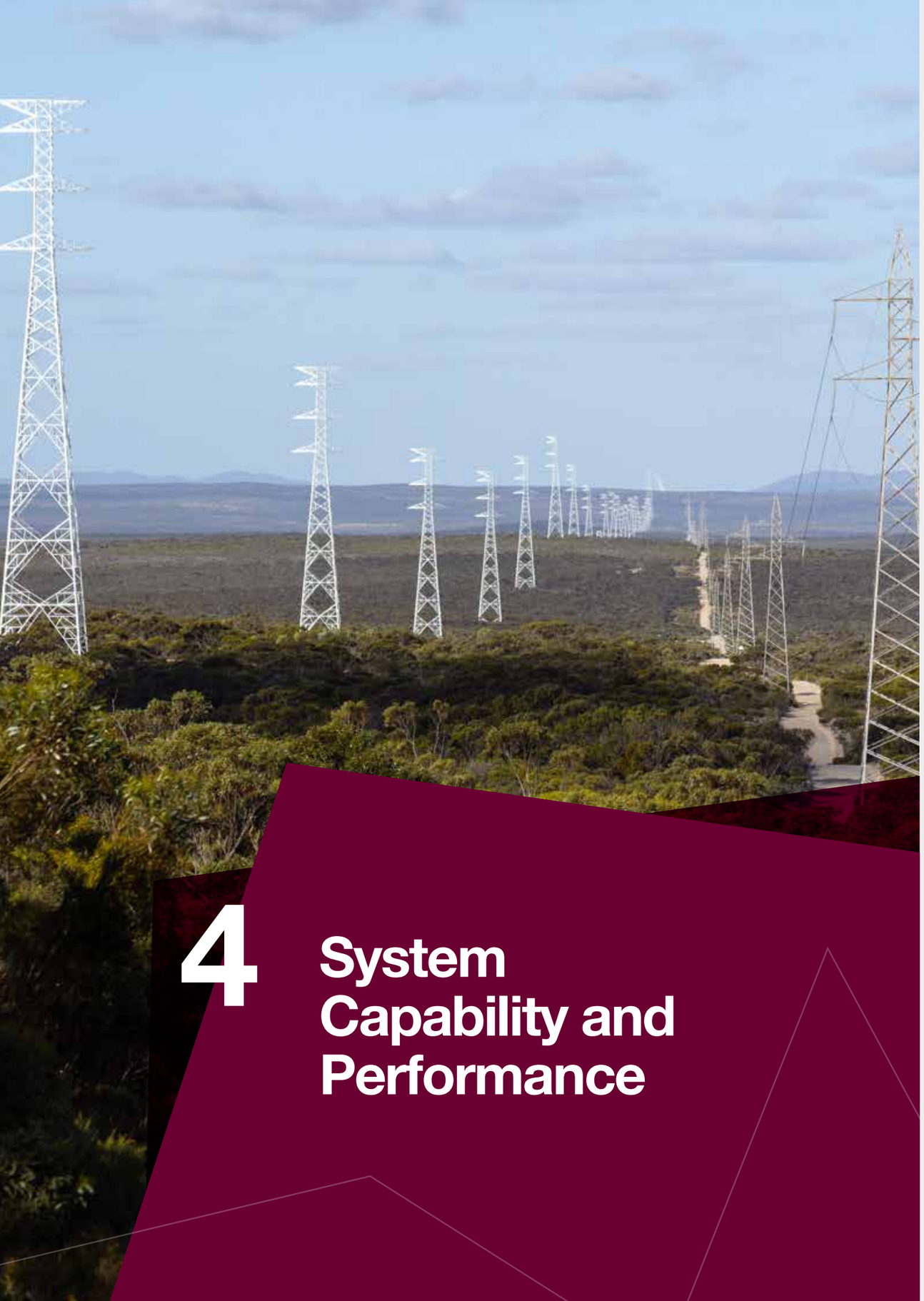
In October 2022 SA Power Networks provided its draft 2022 Connection Point demand forecasts. Our initial assessment of connection point capability to supply forecast maximum demand indicates that forecast maximum demand at Tailem Bend substation could exceed connection point capability within the next 5 years. We will investigate the nature and operating characteristic of the forecast load increases in the coming months to develop our understanding, and assess the risks and identify options to manage these risks.

3.4.4 Connection point minimum demand review

In the year from September 2021 to September 2022, over three quarters of our connection points with SA Power Networks experienced negative power flows. These typically occurred on mild, sunny weekend days, when high distributed rooftop PV generation coincided with low underlying local demand.

A small number of connection points are forecast to have reverse power flows that exceed their existing reverse power capability by about 2027. We discuss potential actions to address these connection points in section 7.5.

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



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 Volts (132 kV) and 275,000 Volts (275 kV), which are supported by both lattice towers and large stobie poles. It connects the major South Australian load centres with various sources of generation (Figure 10).

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 seven regional networks: 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.

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.

An upgrade of Heywood interconnector was completed in mid-2016, increasing interconnector transfer capacity to 600 MW (import) and 550 MW (export). The combined maximum transfer capacity between South Australia and Victoria under normal conditions is now about 820 MW[26] for imports to South Australia, and 700 MW[27] for exports.[28]

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.

The South Australian transmission network consists of transmission lines operating at 132,000 Volts (132 kV) and 275,000 Volts (275 kV), which are supported by both lattice towers and large stobie poles.

[26] Consisting of 600 MW import through Heywood interconnector and 220 MW import through Murraylink interconnector.
[27] Consisting of 550 MW export through Heywood interconnector and 150 MW export through Murraylink interconnector.
[28] At time of writing, transfer capability is restricted to lower levels due to the outage of one Para SVC.

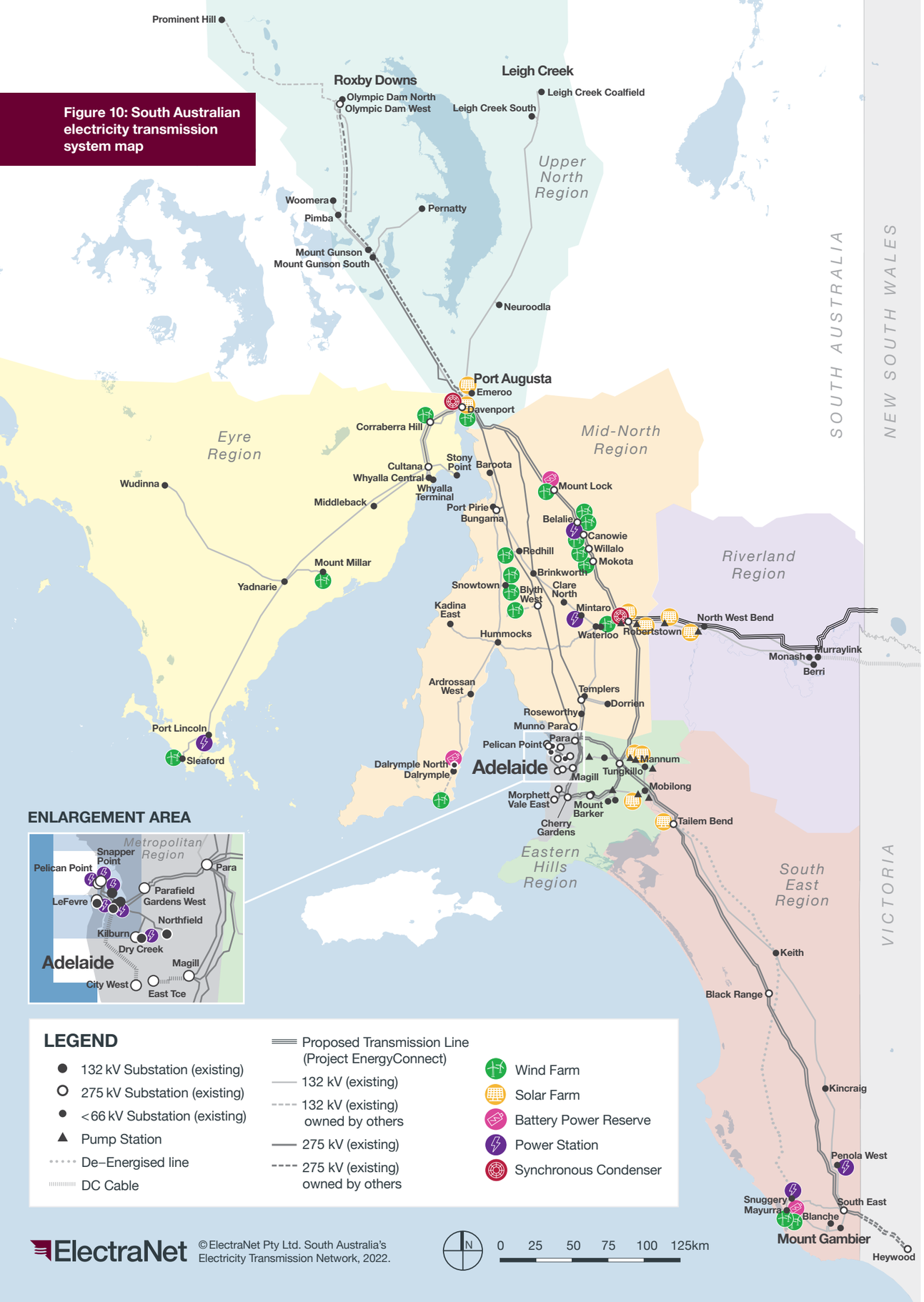


Figure 10: South Australian electricity transmission system map

4.2 Transmission system constraints in 2021

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 the top 20 network constraints in terms of their binding impact on transmission network and interconnector flows during the 2021 calendar year (Table 6) – each of these had a binding impact of at least $150,000 during 2021.

Table 6: Constraint equations, descriptions and impact in 2021

Network limitation	Binding impact 2021 ($)	Binding hours 2021 (hours)	Comments, with proposed and implemented actions
S>NIL_MHNW1_MHNW2 Avoid an overload of Monash – North West Bend 132 kV line No.2 if the Monash – North West Bend 132 kV line No.1 was to trip	$8,487,751.4	1,722.6	This constraint will be alleviated when project EC.15175 Increase Murraylink Transfer Capacity upgrades the existing runback control scheme to include bi-directionality and allow it to run forward if required
S_NIL_STRENGTH_1 Constrain the total output of non-synchronous generation based on system strength requirements in South Australia	$7,697,221.2	649.0	Installation of synchronous condensers at Davenport and Robertstown in 2021 has alleviated the impact of this constraint by increasing the level at which it binds to 2,500 MW when all synchronous condensers are in service
S^SETX_GEN_CAP With one South East 275/132 kV transformer out of service, avoid voltage collapse if the other South East 275/132 kV transformer was to trip	$2,172,976.0	273.3	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
S-X_2DV+2RB_STRGHT_1 Constrain the total output of non-synchronous generation in South Australia to a lower level if all South Australian synchronous condensers are out of service	$2,084,424.6	200.6	Installation of synchronous condensers at Davenport and Robertstown in 2021 has alleviated the impact of this constraint by increasing the level at which it binds to 2,500 MW when all synchronous condensers are in service
S>NIL_HUWT_STBG2 Avoid an overload of the Snowtown to Bungama 132 kV line if the Hummocks to Waterloo 132 kV line was to trip	$1,903,054.9	217.1	We are monitoring this constraint to determine if the implementation of our proposed EC.15571 10-band rating NCIPAP project is likely to alleviate this constraint
SA_ISLE_STRENGTH_BU Constrain output of Bungala Solar Farm if all South Australian synchronous condensers are out of service when South Australia is islanded or at risk of islanding from the rest of the NEM	$1,370,091.8	115.8	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
S-SNWWF_0 Discretionary constraint applied to Snowtown Wind Farm	$635,196.9	53.8	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
S_SECB_LG-1 Constrain the output of Ladbroke Grove Power Station to maintain oscillatory stability if CB6186 or CB6187 are out of service	$617,261.5	39.3	AEMO invokes this constraint when needed to satisfactorily manage the transmission system

Network limitation	Binding impact 2021 ($)	Binding hours 2021 (hours)	Comments, with proposed and implemented actions
V^^SML_NSWRB_2 Constrain transfer across Murraylink from Victoria to South Australia to avoid voltage collapse at Red Cliffs if one of two transmission lines in NSW was to trip	$503,101.1	59.3	The commissioning of Project EnergyConnect Stage 1 is expected to alleviate this constraint
S>>RBTX_WEWT_RBTX With one of the Robertstown 275/132 kV transformers out of service, avoid an overload of the remaining Robertstown 275/132 kV transformer if the Waterloo East-Waterloo 132 kV line was to trip	$496,421.0	66.8	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
S>DVTX_NIL_DVTX With one of the Davenport 275/132 kV transformers out of service, avoid an overload of the remaining Davenport 275/132 kV transformer	$490,992.9	40.7	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
SS_SECB_LG3 Constrain the output of Ladbroke Grove Power Station to maintain oscillatory stability if CB6186 or CB6187 are out of service	$392,501.7	25.1	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
SV_420_DYN Apply an upper limit of 420 MW to flows from South Australia to Victoria across the Heywood interconnector	$327,039.9	330.8	The return to service of Para SVC No. 2 by project EC.15320 Para SVC 2 Transformer Emergency Replacement will resolve the need for this constraint
S>SETX_NIL_SETX With one of the South East 275/132 kV transformers out of service, avoid an overload of the remaining South East 275/132 kV transformer	$321,265.8	84.6	An automatic control scheme to alleviate this constraint is in service under system normal conditions
S>SE6161_SETX2_SGBL With CB6161 out of service, avoid an overload of the Snuggery-Blanche 132 kV line if South East 275/132 kV transformer 2 was to trip	$293,813.6	71.6	AEMO invokes this constraint when needed to satisfactorily manage the transmission system

Network limitation	Binding impact 2021 ($)	Binding hours 2021 (hours)	Comments, with proposed and implemented actions
SVML^NIL_MH-CAP_ON Constrain Murraylink transfers from South Australia to Victoria to avoid voltage collapse at Monash	$213,298.5	283.3	Proposed project EC.15175 Increase Murraylink transfer capacity will alleviate this constraint
S_TIPSB_270 Constrain total output of Torrens Island B Power Station to no more than 270 MW	$197,234.3	2.2	AEMO invokes this constraint when needed to satisfactorily manage the transmission system
V_S_ROCOF With South Australia at credible risk of operation from the rest of the NEM, limit Heywood transfers from Victoria to South Australia to prevent the rate of change of frequency in South Australia from exceeding 1 Hz/s if a separation event was to occur	$179,632.3	2.8	The commissioning of Project EnergyConnect Stage 2 is expected to alleviate this constraint
SA_ISLE_STRENGTH Constrain the total output of non-synchronous generation below 1,900 MW based on system strength requirements in South Australia while South Australia is at risk of separation or already islanded from the rest of the NEM	$171,446.0	13.4	The commissioning of Project EnergyConnect Stage 2 is expected to alleviate this constraint
S>NIL_HUWT_STBG3 Lorem Ipsum Limit Snowtown Wind Farm generation output to avoid overload of the Snowtown-Bungama 132 kV line if the Hummocks-Waterloo 132 kV line was to trip	$168,272.3	16.0	We are monitoring this constraint to determine if the implementation of our proposed EC.15571 10-band rating NCIPAP project is likely to alleviate this constraint

4.3 Emerging and future network constraints and performance limitations

The implementation of Project EnergyConnect, establishing a new interconnector between South Australia and New South Wales, is expected to change dispatch patterns of existing generators and continue to support renewable energy generation connections in South Australia. In combination, this is expected to lead to changes in congestion patterns on the transmission network.

ElectraNet forecasts the emergence of congestion on the South Australian transmission network based on committed, anticipated and modelled expansion of generator investments in the state. There is inherent uncertainty in supply side forecasting where decisions are in large discrete blocks. Scenarios tested by AEMO highlight potential diverging paths for the network. The *Hydrogen Superpower* scenario shows the potential need for massive transmission and generator developments in South Australia to accompany hydrogen exports on a global scale (section 2.1.3).

Network limitations that may emerge under the *Step Change* scenario are highlighted in the table below. These limitations are required to manage the increasing demand on the network to meet electrification.

Renewable energy developments in the South East could see congestion develop between Tailem Bend and the Adelaide metropolitan area beyond what is indicated below.

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

These areas are consistent with the REZs identified for potential development in AEMO's 2022 ISP, requiring ElectraNet to undertake preparatory works for the South East SA and Mid North SA REZs.

A high volume of renewable energy developments on Eyre Peninsula could see congestion develop between Cultana and Davenport.

Considerable congestion is forecast to occur on Project EnergyConnect immediately after commissioning. In general, and across the South Australian network, congestion is forecast to grow substantially during the 2030s.

We are investigating constraints applied to existing generators and potential new generation and battery connections in the Western Suburbs and Northern Suburbs of the Adelaide metropolitan region. These constraints are applied to generators and battery output when any of the 275 kV transmission lines in the 275 kV loop from Torrens Island – LeFevre – Pelican Point – Parafield Gardens West – Para are out of service, either due to planned works or following an unplanned event.

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.

Table 7: Forecast South Australian transmission network congestion

Limitation	Forecast binding hours		Potential mitigating project(s)
	2025 - 2030	2031 - 2040	
Project EnergyConnect (NSW Thermal)	1,200	900	ElectraNet is examining the potential to expand Project EnergyConnect. Since gaining regulatory approval, development such as VNI West and upgrading of the Dinawan to Wagga Wagga section to 500 kV may present a future expansion opportunity Enhanced SPS expanding the combined interconnector limits
Project EnergyConnect exports (800 MW)	1,200	3,900	
Project EnergyConnect imports (800 MW)	200	300	
Combined state-wide Import Limits	100	100	ElectraNet examination of Project EnergyConnect expansion. Enhanced SPS expanding the combined interconnector limits.
Combined state-wide Export Limits	700	1,500	
Heywood Corridor	<100	200	Preparatory works on South East REZ, focusing on the section of the interconnector between Tailem Bend and Adelaide that has low cost options Future expansion of interconnection to Heywood or Bulgana may also be possible
Heywood: Tailem Bend to Adelaide	200	400	
Loss of a Mid North 275 kV line overloading the parallel 132 kV corridor	500	2,700	Preparatory works on Mid North SA REZ, focusing on the transfer corridor Project EnergyConnect and Adelaide as considerable generator interest is being registered in the area Longer term, expansion between Project EnergyConnect and Whyalla may open up additional wind resources, reduce the cost of connecting mining loads in the north east of the state and supply a future hydrogen industry
Robertstown to Tungkillo 275 kV	300	2,600	

4.4 Potential projects to enable growth

The connection of significant new loads, a change in the nature of the generation fleet, increasing gas prices or a rapid electrification of the economy 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.

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 8). 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. Some of these projects may be triggered as contingent projects through the ISP.

Table 8: Potential projects to address future constraints

Renewable Energy Zone	Scope	Identified Needs
Mid North SA REZ Northern expansion	High capacity 2,000 MVA Bundey to Wilmington	Increased access to renewable generation to support electrification of South Australia consumption, approximately doubling electrical energy demand This project would be developed along with the mid-north southern expansion Support development of Eyre Peninsula or Leigh Creek REZ providing increased access to Project EnergyConnect and Adelaide metropolitan load centre Increased access to renewable generation to support hydrogen hubs Support development of new mining operations in the north east of the state Support development of future interconnection to NSW or Queensland
Mid North SA REZ Southern expansion	High capacity 2,000 MVA Bundey to northern suburbs New substation (such as Globe Derby) in northern suburbs tying together Para and Lefevre Peninsula. ACR duplication City West to southern suburbs	Increased access to renewable generation to support electrification of South Australia consumption, approximately doubling electrical energy demand in the Adelaide Metropolitan region Increased access to renewable generation to support hydrogen hub developments Reduce supply risk to Adelaide metropolitan region for catastrophic bushfire in the Adelaide Hills impacting on essential transmission supply corridors Reduced impact of contingency in northern Adelaide reducing supply from Lefevre Peninsula, Torrens Island and Parafield Gardens West
South East SA REZ	High capacity 2,000 MVA Bundey to South East South Australia to Victoria (Heywood or Bulgana) Southeast collection point for onshore and offshore wind.	Increased access to renewable generation to support electrification of South Australia consumption, approximately doubling electrical energy demand Increased interconnection between South Australia and Victoria providing access to diverse renewable resources and dispatchable capacity Increased access to renewable energy generation including diversified generation profile of both onshore and offshore wind Alternative transmission corridor could reduce the risk of bushfires affecting electrical supply through the Adelaide Hills Victorian termination likely to be determined by congestion forecasts on the Victorian 500 kV network extending to Bulgana and Heywood in western Victoria
Northern SA REZ	High capacity 2,000 MVA Wilmington to Cultana	Increased access to renewable generation to support electrification of South Australia consumption, circa doubling electrical energy demand Increased access to renewables generation for hydrogen hub developments or other large expansion of energy needs within South Australia. AEMO's ISP *hydrogen superpower* scenario forecasts South Australian energy consumption increases 20 times by 2050
Eastern Eyre REZ	Stage 1: 275 kV upgrade of Eyre Peninsula link Stage 2: Very high-capacity upgrade of Yadnarie to Cultana	Increased access to renewables generation for hydrogen hub developments or other large expansion of energy needs within South Australia AEMO's ISP *hydrogen superpower* scenario forecasts South Australian energy consumption increases 20 times by 2050
Western Eyre REZ	Very high-capacity upgrade of west coast to Cultana	
Leigh Creek REZ	Very high-capacity upgrade between Leigh Creek and Cultana.	

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 , 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. 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
- implementing 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 has worked 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.

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 has recently reviewed the OFGS scheme for South Australia and has recommended:

- Increasing OFGS capacity by adding additional generators to the scheme
- Implementing delayed trip settings

ElectraNet will be working with AEMO to implement the final recommendations.

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. 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.

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.

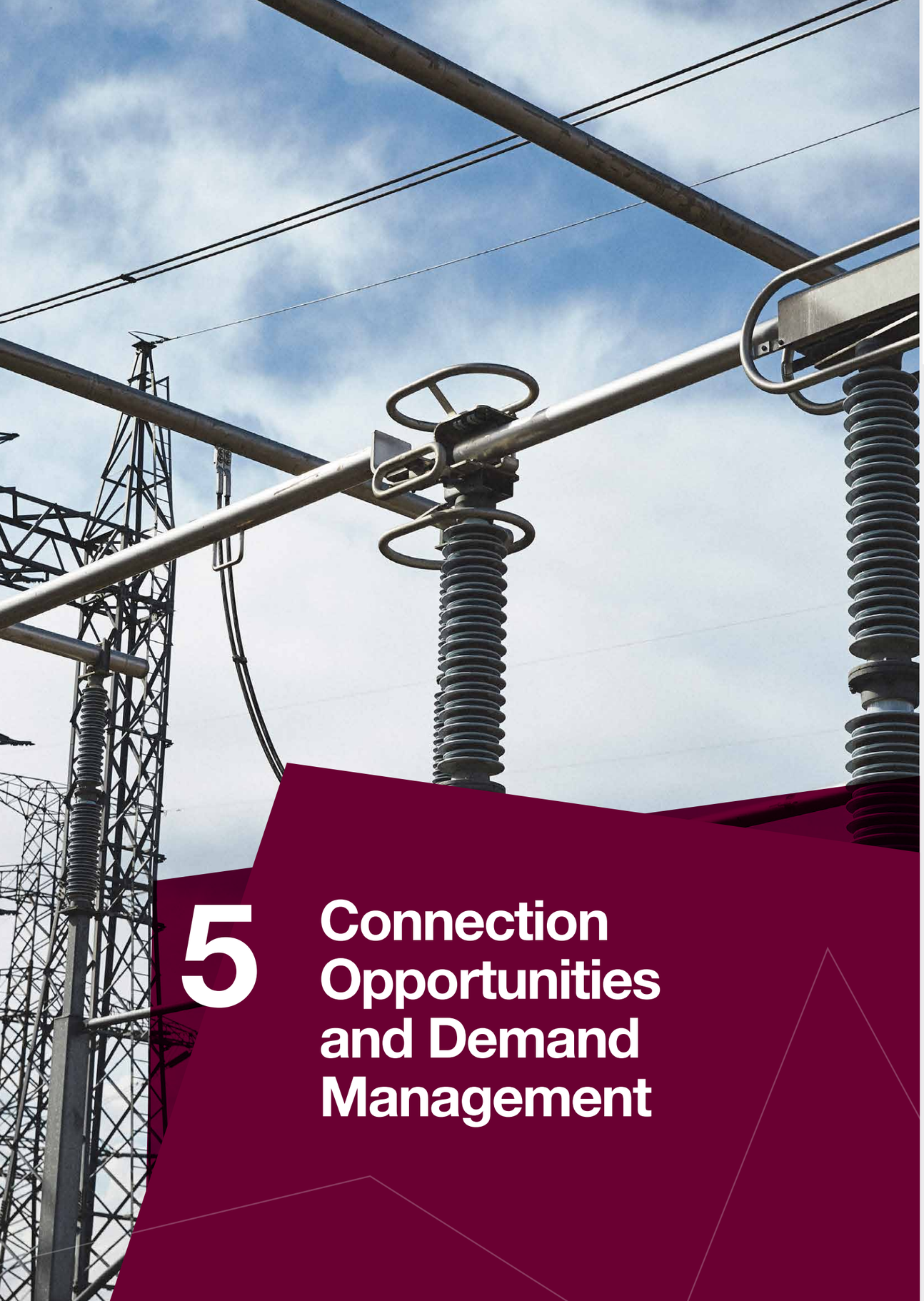
AEMO recommended an investigation of technologies and solutions to upgrade the existing SIPS, considering:

- 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.

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.

Detailed design of the WAPS scheme is currently underway and we expect the WAPS to be in service by March 2023.



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[29].

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 generators have connected or withdrawn since the publication of the 2021 Transmission Annual Planning Report, and other generators are committed to connect, or have announced their intention to withdraw (Table 9).[30]

Table 9: Generators that have connected or withdrawn since 30 October 2021, or are committed to connect or withdraw

Generator	Type	Size	Location	Status
Adelaide Desalination Plant	Storage – battery Solar PV	6.27 MW 13 MWh 24 MW	Southern Suburbs	Committed
Bolivar Power Station	Open Cycle Gas Turbine	123.1 MW	Northern Suburbs	Anticipated in 2022
Christies Beach Wastewater Treatment Plant	Storage – battery Solar PV	2.09 MW 4 MWh 4.8 MW	Southern Suburbs	Committed
Happy Valley Reservoir	Storage – battery Solar PV	4.41 MW 9 MWh 8.34 MW	Southern Suburbs	Committed
Bolivar Waste Water Treatment	Storage – battery Solar PV	2.46 MW 5 MWh 11.25 MW	Northern Suburbs	Committed
Mannum – Adelaide Pumping Station No. 2	Solar PV	16.8 MW	Mannum – Adelaide No. 2 Pumping Station	Committed
Mannum – Adelaide Pumping Station No. 3	Solar PV	12.36 MW	Mannum – Adelaide No. 3 Pumping Station	Committed
Morgan to Whyalla Pipeline No. 1 PS and Filtration Plant	Solar PV	6.12 MW	Morgan – Whyalla No. 1 Pump Station	Committed
Morgan to Whyalla Pipeline No. 2 PS	Solar PV	5.88 MW	Morgan – Whyalla No. 2 Pump Station	Committed
Morgan to Whyalla Pipeline No. 3 PS	Solar PV	7.38 MW	Morgan – Whyalla No. 3 Pump Station	Committed

[29] *ElectraNet website, www.electranet.com.au/what-we-do/solutions/connection-services/*

[30] *Sourced from AEMO's NEM Generation Information August 2022, available at www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/ nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.*

Generator	Type	Size	Location	Status
Murray Bridge – Onkaparinga Pipeline	Solar PV	13.74 MW	Murray Bridge Pump Station 2	Committed
Lincoln Gap Wind Farm BESS	Storage - battery	10 MW 10 MWh	Corraberra Hill	Anticipated in 2022
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
Port Augusta Renewable Energy Park	Solar PV Wind turbine	79.2 MW 210 MW	Davenport	Committed
Tailem Bend Battery	Storage - battery	5.8 MW 84 MW	Tailem Bend	Anticipated in 2024
Tailem Bend Stage 2 Solar	Solar PV	105 MW	Tailem Bend	Committed
Torrens Island BESS	Storage - battery	250.7 MW 250 MW	Torrens Island	Anticipated in 2023
Torrens Island A3	Turbine - Steam sub critical	120 MW	Torrens Island	Withdrawn September 2022
New Osborne	Combined cycle gas turbine	118 MW 62 MW	Osborne	Planned withdrawal 31 December 2023
Temporary Generation South	Open cycle gas turbine	123.1 MW	Southern Suburbs	Withdrawn 1 May 2022

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 two system conditions (Table 10). These were selected to represent 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.

Table 10: 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	90	150 (import)	150 (import)	20%	45%	100%
High winter demand very windy and overcast	2,000	130	100 (export)	100 (import)	5%	90%	0

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. Connection between Tailem Bend and South East is complicated by series compensation at Black Range and is unlikely to be cost effective.

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 any of these locations 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 distributed rooftop solar PV, generation constraints can be significantly more onerous than presented in section 5.2.1. 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 transmission system may have capacity to accept new generation connections, population density may limit the ability to economically extend the network. Also, existing maximum fault levels are approaching the plant capability limits of our 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 assets to address fault level issues.[31]

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.

We 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. 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.[32]

The synchronous condensers have enabled the SA system to be operated securely with only two large synchronous generator units in-service. ElectraNet with AEMO is examining the system limits that would apply with only one synchronous unit in-service.

The total installed and committed 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, other constraints such as for 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.

[31] *Expected maximum and minimum fault levels for each connection point are available from our Transmission Annual Planning Report web page, available at www.electranet.com.au/what-we-do/solutions/connection-services/*

[32] *AEMO, Transfer Limit Advice – System Strength VIC and SA v42, page 9, published September 2022. 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.

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 submitted and progressed as soon as Project EnergyConnect reaches Considered Project[33] 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 information to prepare a formal Connection Application.

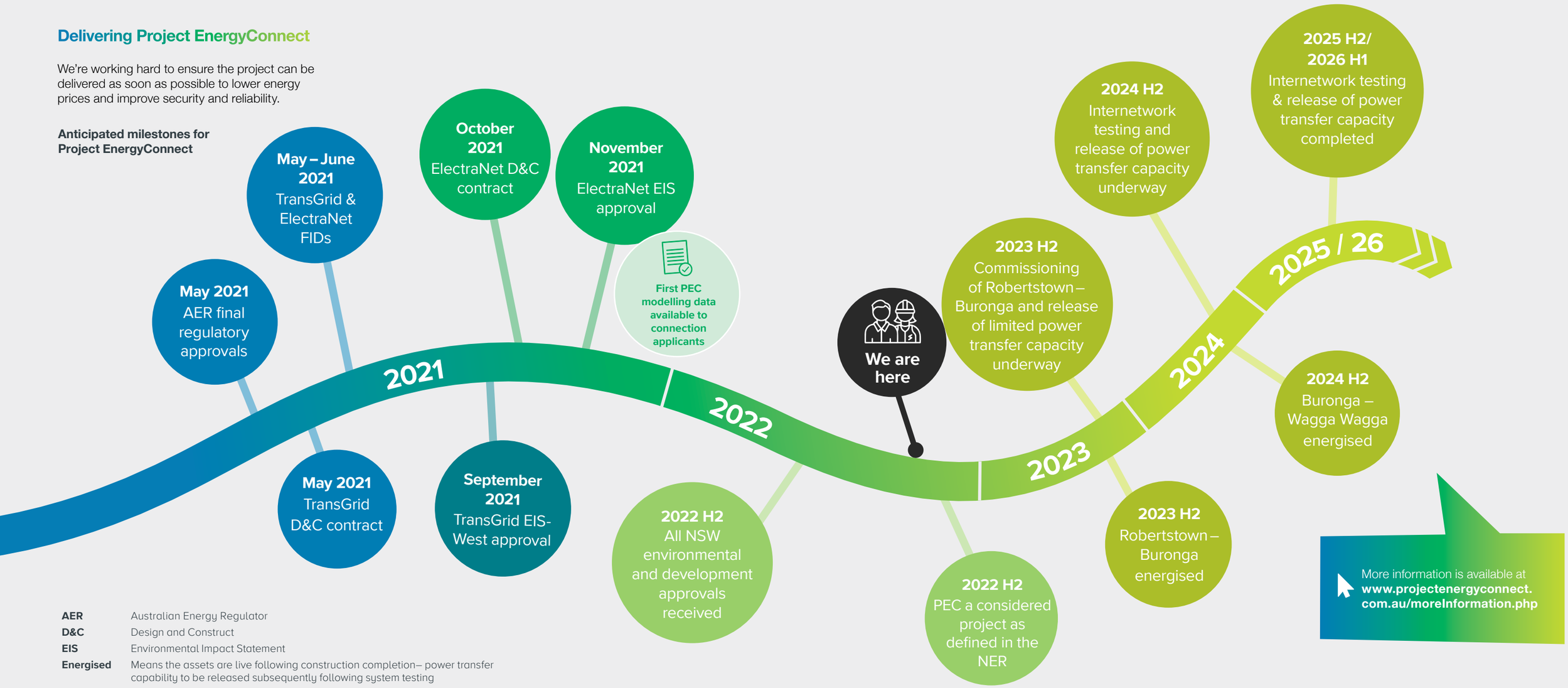
PEC models have reached sufficient maturity to be used for planning purposes. These planning models are available to Connection Applicants via the normal AEMO process. PEC will reach Considered Project status in the second half of 2022. Updates[34] on this progress will be shared regularly by ElectraNet and TransGrid.

ElectraNet anticipates Project EnergyConnect will reach considered project status by the end of 2022.

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



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

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

[34] *Project EnergyConnect website, www.projectenergyconnect.com.au/moreInformation.php?page=2*

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[35], 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. Since then, loads have generally remained flat. However, the most recent maximum demand forecasts from AEMO and SA Power Networks indicate potential load growth for the next ten years and are higher than 2021 demand forecasts.

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 100% of capacity
- Wind farms dispatched to 2% of capacity
- Solar farms off
- Import of 600 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 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.[36]

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.

[35] 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.

[36] 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://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information*

Table 11: 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)
	High winter demand Very windy, overcast	High summer demand Sunny at noon	Very high summer demand Low wind, early evening
Main Grid (275 kV)			
Belalie	300	400	300+
Blyth West	110	300	300+
Brinkworth	220	350	250
Bundey	460	530	300+
Bungama	110	400	300+
Canowie	290	400	300+
Cherry Gardens	600+	600+	300+
City West	600+	530	180
Corraberra Hill	240	350	300+
Cultana	290	430	300+
Davenport	400	600+	300+
Happy Valley	600+	600+	300+
Kilburn	540	550	100
Le Fevre	600+	600+	300+
Magill	600+	600+	300+
Mokota	270	400	300+
Morphett Vale East	590	600+	180
Mount Barker South	600+	600+	300+
Mount Lock	290	380	300+
Mt Gunson South	270	230	30
Munno Para	280	280	100
Northfield	600+	600+	150
Para	600+	600+	300+
Parafield Gardens West	600+	380	300+
Pelican Point	600+	380	300+
Robertstown	460	530	300+
South East	600+	400	300+
Tailem Bend	600+	400	300+
Templers West	150	200	300+
Torrens Island	600+	600+	300+
Tungkillo	600+	600+	300+
Willalo	280	400	300+

Connection point	Additional generation that could be connected (MW)		Additional load that could be connected (MW)
	High winter demand Very windy, overcast	High summer demand Sunny at noon	Very high summer demand Low wind, early evening
Upper North (132 kV)			
Leigh Creek South	5	5	0
Mount Gunson	50	60	10
Mount Gunson South	210	230	30
Neuroodla	5	5	0
Pimba	50	60	10
Eyre Peninsula (132 kV)			
Cultana	170	260	90
Port Lincoln Terminal	120	130	90
Whyalla Central	150	180	5
Wudinna	70	80	20
Yadnarie	120	130	90
Eastern Hills (132 kV)			
Angas Creek	100	110	80
Back Callington	50	60	0
Cherry Gardens	120	130	100
Kanmantoo	20	30	5
Mannum	120	110	80
Mannum–Adelaide Pump Station No 1	10	0	0
Mannum–Adelaide Pump Station No 2	120	110	80
Mannum–Adelaide Pump Station No 3	120	110	80
Millbrook	5	0	0
Mobilong	300	130	140
Mount Barker	220	180	100
Murray Bridge-Hahndorf No 1	70	80	60
Murray Bridge-Hahndorf No 2	160	160	140
Murray Bridge-Hahndorf No 3	160	160	140
Para	120	160	80

Connection point	Additional generation that could be connected (MW)		Additional load that could be connected (MW)
	High winter demand Very windy, overcast	High summer demand Sunny at noon	Very high summer demand Low wind, early evening
Mid North and Riverland (132 kV)			
Ardrossan West	10	30	20
Baroota	50	10	0
Berri	40	110	5
Brinkworth	20	230	80
Bungama	50	160	100
Clare North	20	160	30
Dalrymple	10	30	20
Dorrien	30	130	70
Hummocks	10	110	20
Kadina East	10	110	20
Monash	40	180	5
Morgan–Whyalla Pump Station No 1	40	230	5
Morgan-Whyalla Pump Station No 2	40	230	5
Morgan–Whyalla Pump Station No 3	40	210	5
Morgan–Whyalla Pump Station No 4	10	110	10
North West Bend	40	180	5
Port Pirie	50	160	10
Roseworthy	90	130	90
Templers	10	160	90
Templers West	40	110	80
Waterloo	10	180	20
South East (132 kV)			
Blanche	10	80	40
Keith	70	30	80
Kincraig	70	80	80
Mt Gambier	10	80	40
Penola West	50	110	160
Snuggery	0	80	90
South East	50	100	160
Tailem Bend	170	10	80

5.5 Proposed and committed new connection points

New connection points have recently been energised, committed, or are proposed to enable the connection of new generators or loads (Table 12).

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.

Table 12: Proposed, committed, and recently energised new connection points for generators and customers

Connection Point	Planning Region	Project year	Connection Voltage	Scope of work
Snapper Point	Metropolitan Adelaide	2022	275 kV	Establish 275 kV connection point to facilitate connection of new generation
Bundey	Mid North	2023	275 kV	Part of Project EnergyConnect – establish Bundey substation with 3 x 400 MVA 275/330 kV transformers to facilitate connection of South Australia via Robertstown 275 kV to the new interconnector

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 13).

Future dates are indicative only. Reports will be published on ElectraNet's website, with a summary on AEMO's website.[37 38] We also liaise with AEMO to notify interested parties when we publish new Regulatory Investment Test for Transmission (RIT-T) reports through the "AEMO Communications" email notifications.[39]

We have service agreements in place for the provision of 200 MW of Fast Frequency Response services for FY2022-23. We are engaging with the market to increase the volume of services available to 360 MW from 1 July 2024 until Project EnergyConnect is in operation.

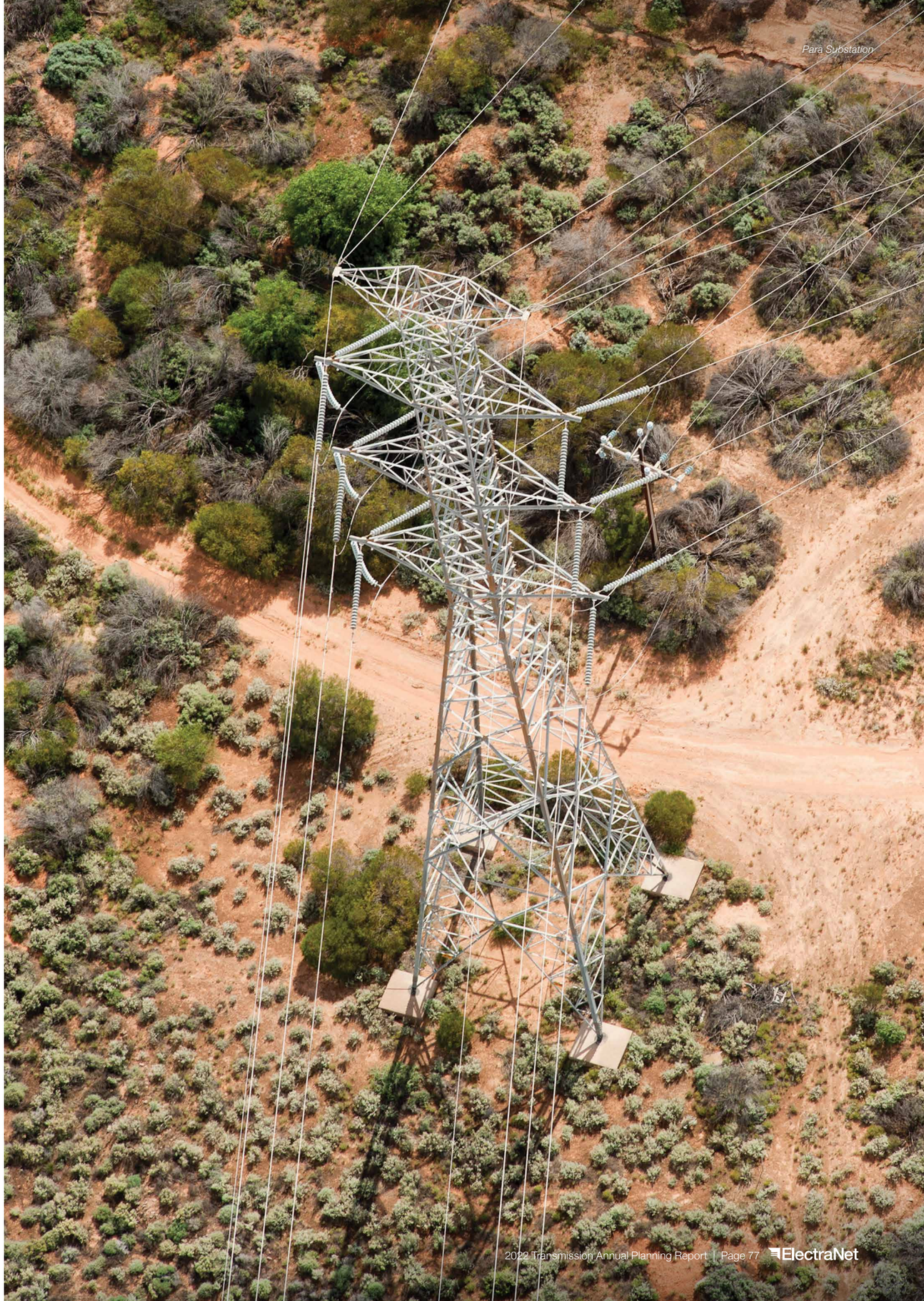
Table 13: Planned consultation for which ElectraNet plans to seek proposals for network support solutions

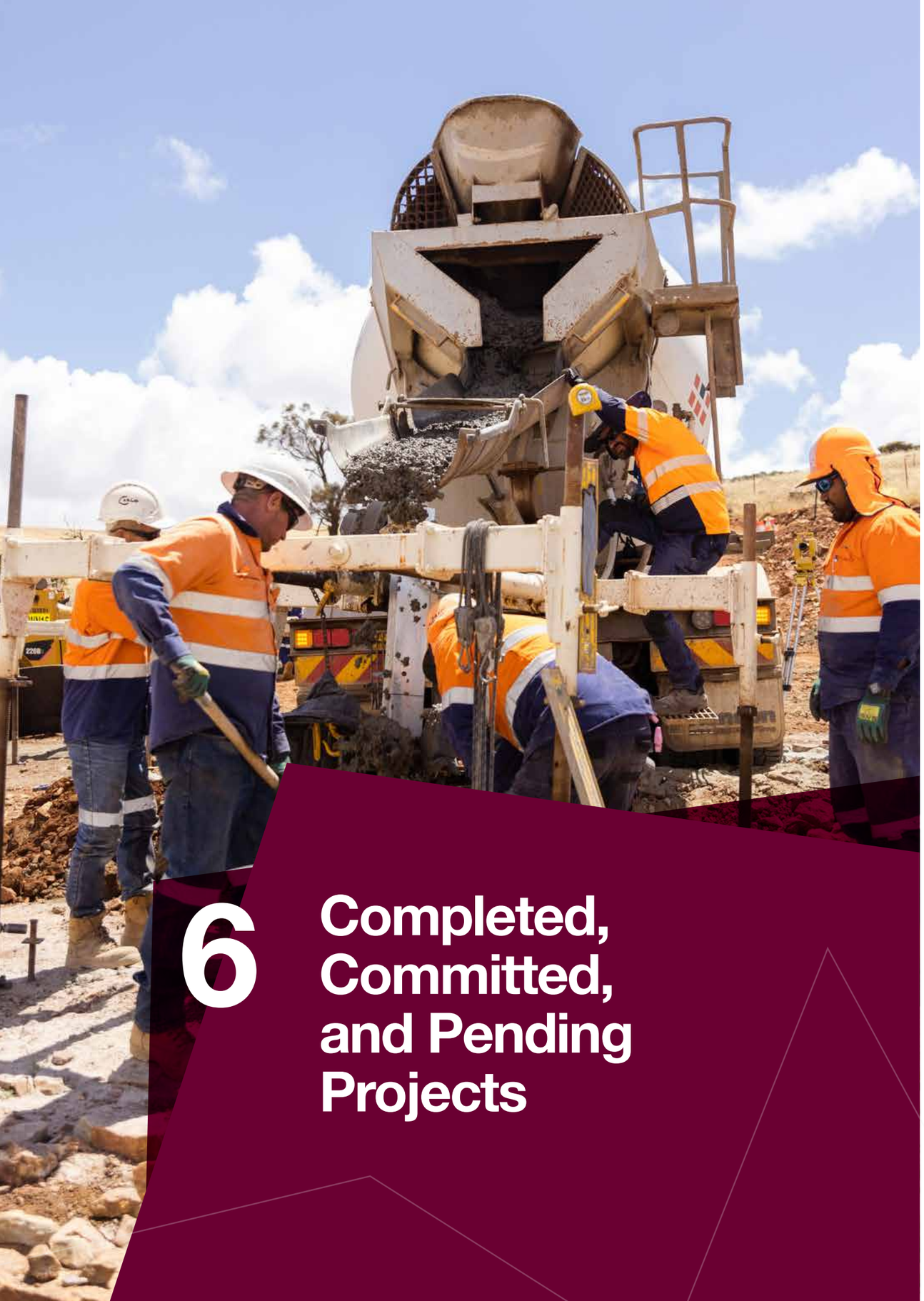
RIT-T	Expected project commitment date	Consultation status
Transmission Network Voltage Control Refer to section 7.4 of this report.	2023	We plan to commence application of the RIT-T with publication of a Project Specification Consultation Report (PSCR) in 2022 Proponents of potential network support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

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

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

[39] 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.





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 14 and Figure 11 overleaf).

Table 14: Network projects completed between 31 October 2021 and 31 October 2022 (inclusive)

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15307 Para SVC 1 Transformer Emergency Replacement Replace the Para SVC 1 transformer and auxiliary equipment that was damaged by a transformer fire in July 2020	Metropolitan	Asset condition and performance Asset renewal	December 2021
EC.11749 AC Board Replacement 2013 – 2018 Replace and improve AC auxiliary supply equipment, switch boards and cabling at 11 substations that are at the end of technical life	Various	Asset condition and performance Asset renewal	May 2022

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 15 and Figure 12 overleaf).

Table 15: Committed projects as of 31 October 2022

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	October 2022 (Port Pirie) July 2023 (Bungama)
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	November 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	November 2022
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	November 2022

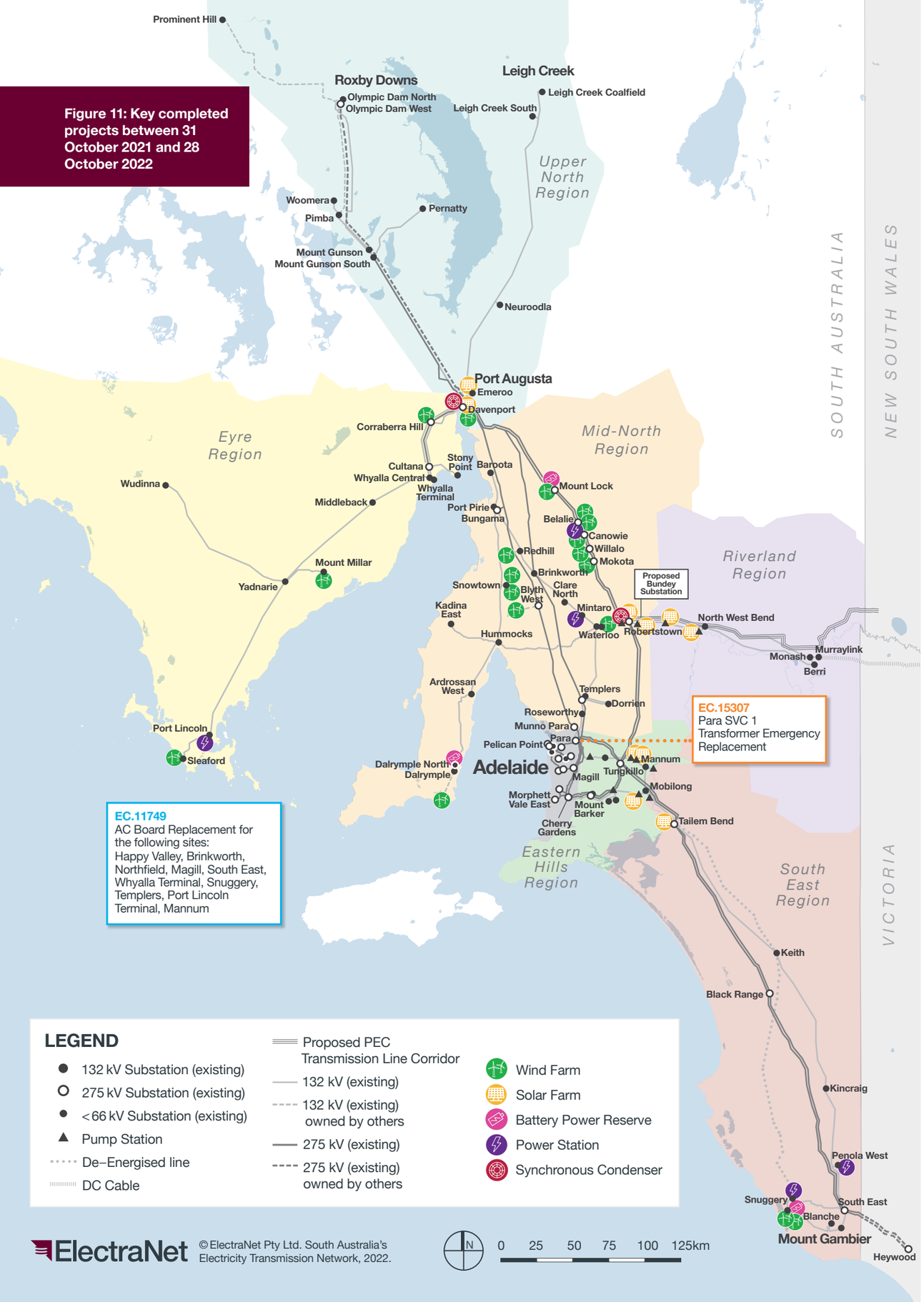


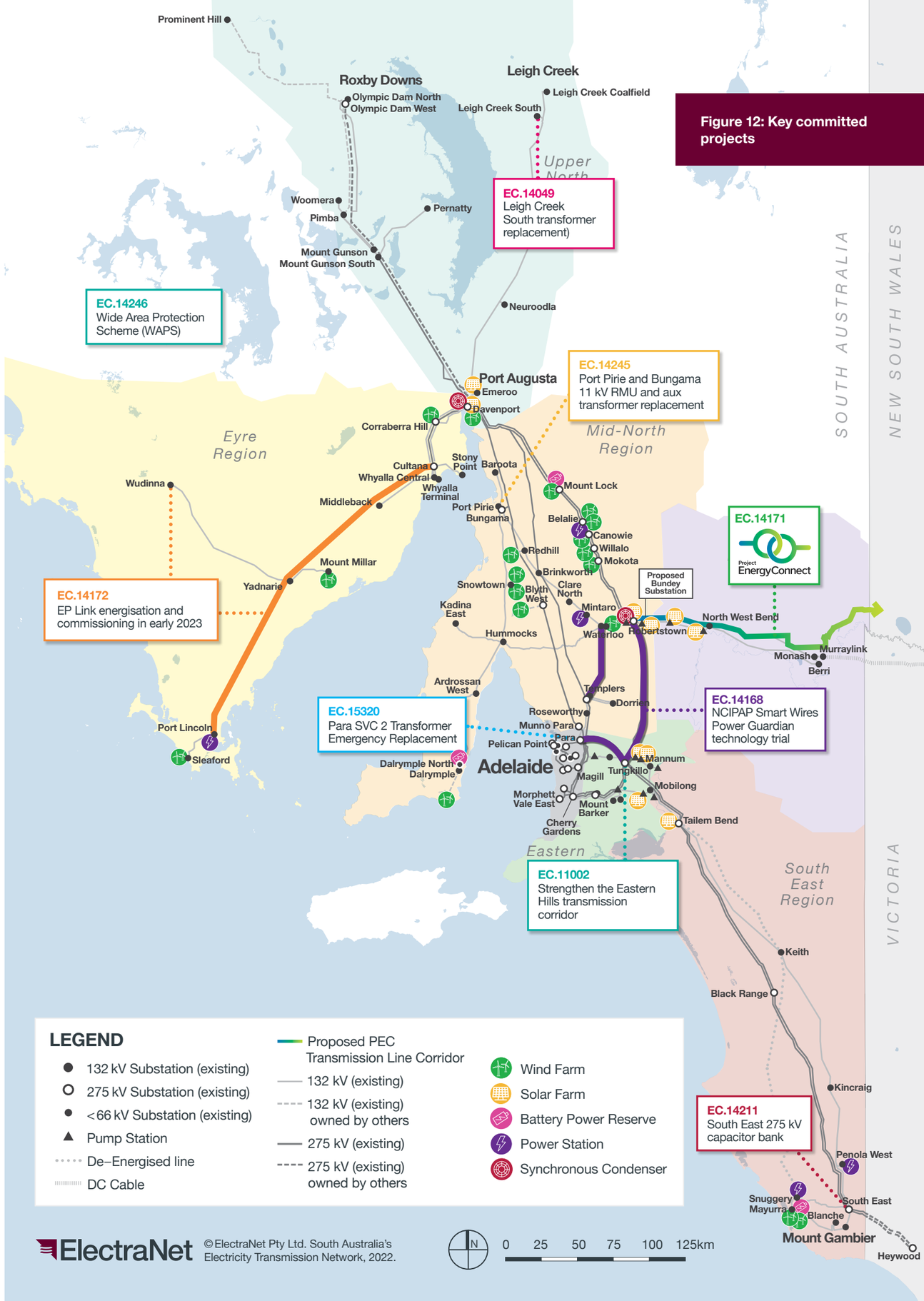
Figure 11: Key completed projects between 31 October 2021 and 28 October 2022

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	January 2023
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, so 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 2023
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	March 2023
EC.14049 Leigh Creek South transformer replacement 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	April 2023
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 Robertstown to Tungkillo 275 kV lines to increase the transfer capacity of the transmission network in the Mid North region of South Australia The Project's planned asset in service date of October 2021 in the 2021 TAPR was delayed due to technical difficulties.	Mid North	Market benefit (NCIPAP) Augmentation	May 2023
EC.11002 Strengthen the Eastern Hills transmission corridor Connect the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo	Eastern Hills	Market benefit (NCIPAP) Augmentation	May 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	June 2023
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	June 2023
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.15320 Para SVC 2 Transformer Emergency Replacement Replace the Para SVC 2 transformer and auxiliary equipment that was damaged by a transformer fire in January 2022	Metropolitan	Asset condition and performance Asset renewal	September 2023

Project Description	Region	Constraint driver and investment type	Planned Asset in service
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): late 2023 Stage 2 (Buronga to Wagga Wagga): late 2024
EC.14047 Transformer Bushing Unit Asset Replacement 2018 – 2023 Replace transformer bushings fitted on 20 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 The number of transformers requiring bushings to be replaced has increased from 16 to 20, as a result of detailed assessment of selected transformer bushings following the failure of similar bushings on other transformers	Various	Asset condition and performance Asset renewal	November 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	November 2023
EC.14127 GE D20 RTU Product Upgrades 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	December 2023
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	January 2024
EC.14031 Protection System Unit Asset Replacement 2018-2023 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	July 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 safety 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	August 2027

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 2022 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.

Our planning scenario is based on the *Step Change* scenario from AEMO's 2022 ISP as the most likely scenario as determined by AEMO's industry panel.

The scenario 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 in Figure 13.

Characteristic	Central scenario	100% net renewables in SA
Connection point demand forecasts	As published in the 2022 connection point data on our Transmission Annual Planning Report webpage[40]	
SA transmission system coincident demand forecasts	AEMO's 2022 ESOO 10% POE maximum demand forecast and 90% POE minimum demand forecast	
Potential new load connections	As shown in map overleaf and Appendix F	
Potential new or retired conventional generators		
Potential new renewable generators		

[40] *Available from www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/*

Figure 13: Assumptions considered in ElectraNet's planning process, including potential future generator retirements and new generator and battery connections

7.1 Summary of planning and development outcomes

Analysis of the planning scenario led to a range of high-level planning outcomes, project recommendations and development outcomes that are required for the scenario (Table 16). Detailed outcomes are covered in sections 7.3 to 7.10.

Potential projects that may be required to support development under other scenarios were covered earlier, in section 4.4.

Table 16: 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 (SA) to Wagga Wagga in New South Wales (NSW). 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. Project EnergyConnect remains an important project for the national electricity grid and a priority project for ElectraNet, AEMO and the federal and state governments. Independent analysis shows Project EnergyConnect is expected to deliver additional net annual savings of around $100 for a typical household in South Australia and up to around $60 for a typical household in New South Wales. It will drive competition in the wholesale electricity market by connecting more, low-cost generation to the grid and support the ongoing transition to a lower carbon emissions future. The Project has now received all necessary Australian Energy Regulator (AER) and Board approvals. Construction commenced in May 2022. Project EnergyConnect remains on track to be delivered in two stages: 1. The completion of construction from Robertstown in South Australia to Buronga in NSW, energisation and commissioning in late 2023, with inter-network testing and release of initial transfer capability up to 150 MW over the following 6 months 2. The completion of the second section from Buronga to Wagga Wagga in NSW, energisation and commissioning in late 2024, with inter-network testing and release of transfer capacity up to 800 MW over 12-18 months, subject to market demand Opportunities to accelerate inter-network testing timeframes are under active consideration.

Planning focus	Key outcomes
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. The synchronous condensers have also enabled the SA system to be operated securely with only two large synchronous generator units in-service. We have agreed with AEMO to study the system limits that would apply with only one synchronous generator unit in-service. Project EnergyConnect will facilitate the operation of the SA system with no synchronous units in service. AEMO has not identified any system strength shortfall in South Australia in its 2021 AEMO System Security Report and since the installation of the synchronous condensers at Davenport and Robertstown in 2021 AEMO had published 2020 inertia requirements in South Australia, determining the secure operating level of inertia for South Australia, proposing 200 MW of fast frequency response (FFR) raise service to be made available for network support until June 2023 to address the inertia shortfall. We have initiated the procurement process and are engaging with the market for the provision of these FFR services from 1 July 2022. A further gap of 360 MW of FFR raise service remains to be addressed from 1 July 2023 until Project Energy Connect is in operation, which we will be working through in the coming months. **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 identified need is supported by dynamic studies undertaken in early 2022. This identified need and options to address the identified will be subject to the Regulatory Investment Test for Transmission (RIT-T). One of the options we are investigating is for project EC.11645 Transmission Network Voltage Control to install a suite of 50-60 Mvar 275 kV reactors at various locations, to enable continued satisfactory voltage control on the South Australian transmission system by maintaining 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.
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 January 2023 **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	We are implementing projects that form ElectraNet's 2018-23 Network Capability Incentive Parameter Action Plan (NCIPAP) that will reduce the impact of existing and forecast network constraints to deliver net market benefits. This includes the project to turn in the Tailem Bend to Cherry Gardens 275 kV line at Tungkillo which will be delivered in May 2023. We have proposed project for inclusion in our 2023-28 NCIPAP as part of our Revenue Proposal for the 2024-2028 revenue control period. These include projects to: • Improve transmission line ratings based on ambient conditions to release constraints on low cost renewable generation from the Mid North and interstate • Manage voltage and reactive power support to improved export capability of low cost renewable generation by installing an additional 15 MVAr capacitor bank at Monash substation and an automated capacitor switching control system • Increase clearances and remove/replace lower rated plant as necessary to increase the design capability of the transmission lines and enable increased flows of low cost renewable energy from the Mid North and Riverland • Remove and replace plant rated lower than the design capability of the transmission lines to release further transfer capacity on the Davenport-Cultana line to enable increased flows of low cost renewable energy from Eyre Peninsula

Planning focus	Key outcomes
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 battery connections in the Mid North, Eyre Peninsula, Upper North and Riverland Regions. There are also potential connections of batteries in metropolitan Adelaide. We are working with South Australia's government to understand the impact of the development of South Australia's renewable energy zones (REZ) and in planning for the emergence of Hydrogen production industry within our state. In addition to Hydrogen production, we continue to receive interests in load development in South Australia that would like to take advantage of our low-cost and low-emission electricity from renewable sources. Among these are large data centres and mine sites. We are preparing to perform early works for South Australia projects in the 2022 ISP. These include increasing power transfer capability between the South East, Mid North and metropolitan Adelaide. We are also reviewing our contingent projects to better prepare our network for any significant changes that may trigger these investments earlier than expected.
Network asset retirements and deratings	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	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 March 2023. As part of Project EnergyConnect a Special Protection Scheme (SPS) 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. We have rolled out a limited Wide Area Monitoring Scheme (WAMS) that uses phasor monitoring units to provide enhanced, high-resolution, time-synchronised wide area system monitoring access across the SA transmission network. We plan to enhance the existing WAMS by installing further phasor measurement units at candidate sites across the SA transmission network, which have been selected in collaboration with AEMO. The 2022 Power System Frequency Risk Review (PSFRR) recommended revisions to constraints on the Heywood interconnector associated with the existing protected event for destructive wind conditions in SA following the completion of WAPS and Project EnergyConnect Stage 1. It also indicates AEMO's intention to explore options to forecast and manage future National Electricity Market (NEM) ramping events (such as have been identified in SA during 2021) resulting from the increasing penetration of distributed solar PV generation and transmission-connected inverter based resources. 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 and priorities.

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.

In January 2022 the Para SVC No.2 transformer and auxiliary equipment were damaged by a transformer fire. Project EC.15320 Para SVC No.2 Transformer Emergency Replacement has been committed to purchase and replace the damaged transformer and auxiliary equipment. This project has an estimated cost of $11.9 million and is scheduled to be complete in September 2023.

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 17 and Figure 14).

We are progressing the upgrade of our existing System Integrity Protection Scheme (SIPS) to a more sophisticated Wide Area Protection Scheme (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 (WAMS). We are considering opportunities to further increase the firm transfer capacity of Project EnergyConnect and the Heywood interconnector, for example by installing relatively low cost dynamic voltage control devices, series capacitors or other flow control devices.

Table 17: 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: **$8-12 million** Status: **Committed** Implement a Wide Area Protection Scheme with the use of phasor measurement units (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 South Australia system security ElectraNet does not envisage that this project will impact inter-regional transfer	All	Stability Operational	March 2023
EC.14171 Project EnergyConnect: New interconnector between South Australia and New South Wales Estimated cost: **$440-500 million** (South Australian component only) 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 The AER approved TransGrid and ElectraNet's Contingent Project Applications in May 2021 with a total cost of $2.27 billion (2017-18 dollars) ElectraNet envisage that this project will impact inter-regional transfer	Main Grid	Market benefit Augmentation	Stage 1 (Robertstown to Buronga): late 2023, followed by inter-network testing Stage 2 (Buronga to Wagga Wagga): late 2024, followed by inter-network testing
EC.15272 Wide Area Monitoring Scheme 2023-2028 Estimated cost: **$10-15 million** Status: **Planned** 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	April 2024
EC.15206 Project EnergyConnect Upgrade Estimated cost: **$100-150 million** Status: **Being proposed as a contingent project in the 2024-2028 regulated period** 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 WAPS, 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	2024 – 2028 (When or if shown to deliver net market benefits)

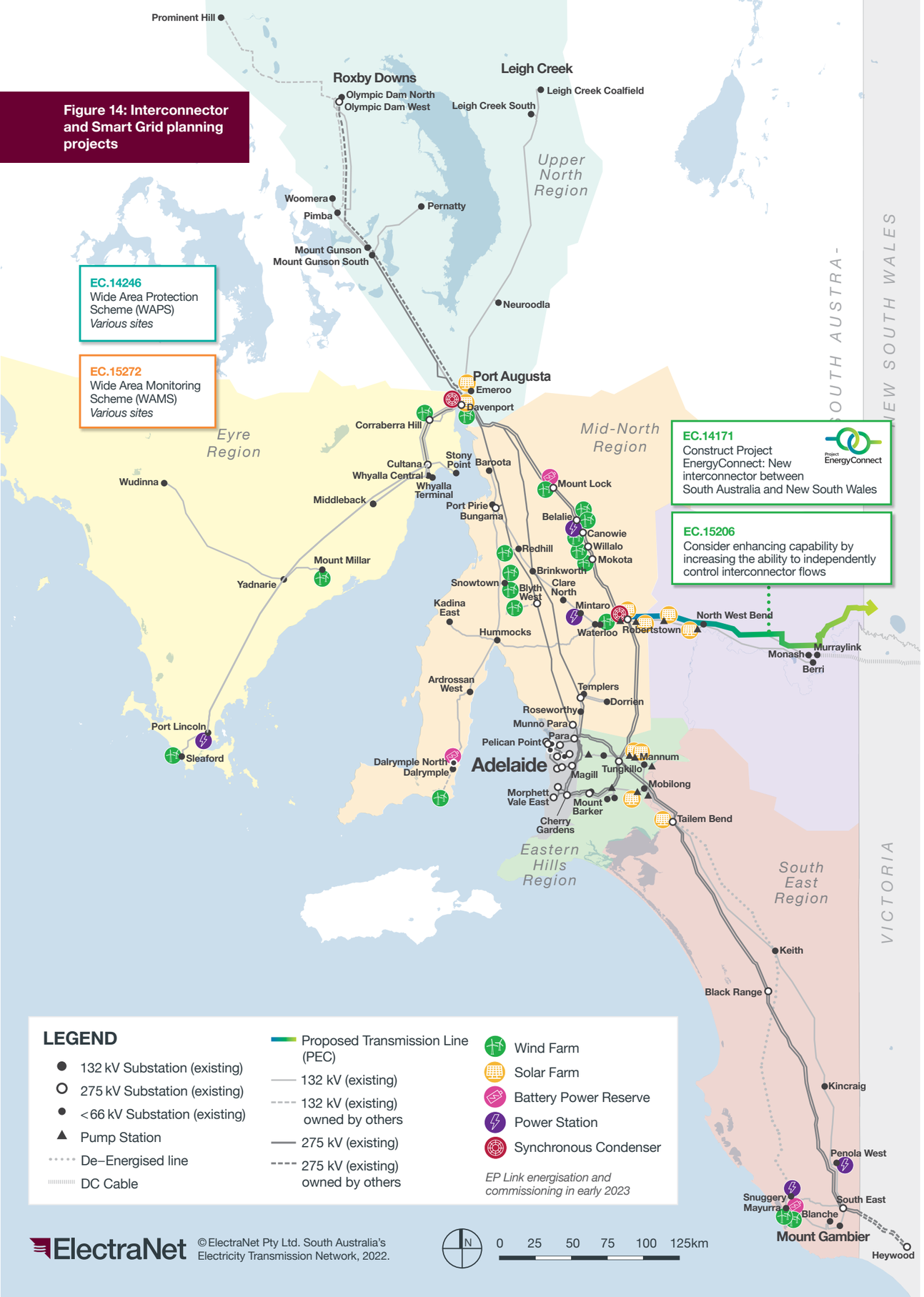


Figure 14: Interconnector and Smart Grid planning projects

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 improve on South Australia transmission network's system strength, inertia and voltage control (Table 18 and Figure 15).

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's review of inertia needs across the NEM confirmed the shortfall that was declared in 2020, for 200 MW of fast frequency response or equivalent inertia support activities, until 30 June 2023. We have contracted with third parties for the provision of the required services.

AEMO also declared a new shortfall, equivalent to 360 MW of fast frequency response or equivalent inertia support activities, from 1 July 2023 until the expected completion of inter-network testing for Project EnergyConnect. We plan to engage the market for provision of the required 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 2022 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 to increase inductive reactive power capability is forecast to be needed at times when there are no conventional generators online during minimum demand 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[41].

The installation of synchronous condensers at Davenport and Robertstown during 2021 has maintained and enhanced the ability to adequately control system voltage levels.

[41] *Transmission Annual Planning Report webpage www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/*

Figure 15: Proposed projects to meet system security, power quality and fault level needs

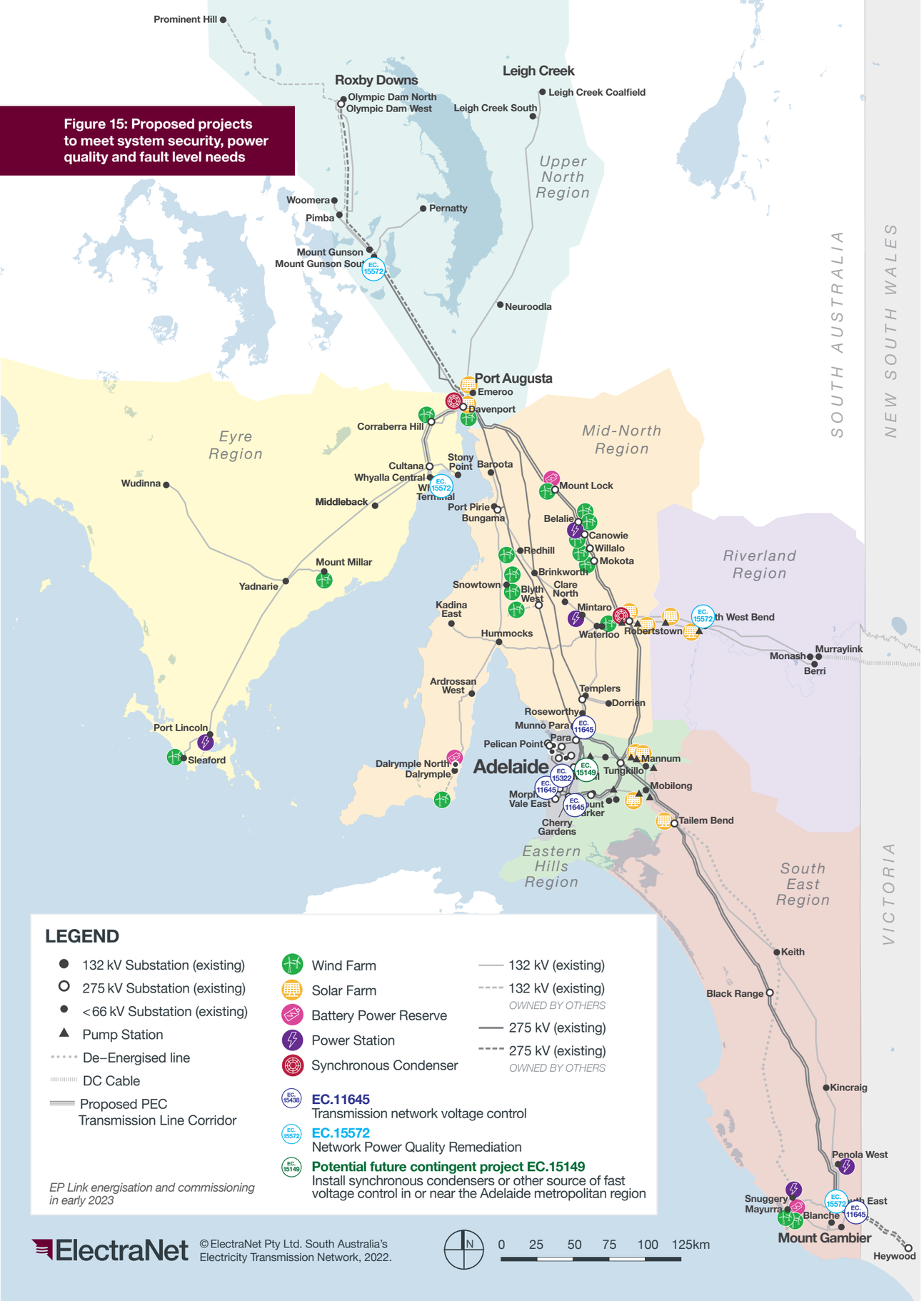


Table 18: Projects proposed to maintain or enhance system security or power quality

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15322 Emergency Transmission Network Voltage Control Estimated cost: **About $7 million** Status: **Being considered** On 1 September 2022 we identified an urgent need to mitigate emerging voltage control risks that are forecast to be experienced at times of very low system demand over the 2022-23 summer. To address this risk we plan to install our existing spare 50 Mvar 275 kV reactor at Happy Valley substation To facilitate connection of the spare 275 kV reactor at Happy Valley we propose to disconnect Happy Valley's existing 100 Mvar 275 kV capacitor, to be stored at Happy Valley connection point. We propose to adjust the scope of EC.11645 Transmission Network Voltage Control (below) to account for the installation of the spare reactor to be installed at Happy Valley, and to include re-connection of the Happy Valley capacitor bank in a different connection arrangement	Metro	Reactive support Augmentation	Summer 2022-23
EC.11645 Transmission Network Voltage Control Estimated cost: **$50-60 million** Status: **Planned** 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	2026
EC.15572 Network Power Quality Remediation Estimated cost: **$30-60 million** Status: **Being proposed as a contingent project in the 2024-2028 regulated period** Install relevant equipment to ensure maintain power quality is maintained for customers across the transmission network in relation to voltage harmonic 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: **If required this would be triggered as a contingent project by a future AEMO ISP** 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 (Table 19 and Figure 16).

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).

Draft demand forecasts indicate a potential need to augment Tailem Bend substation in about 2025. ElectraNet will examine this in more detail with SA Power Networks over the coming year and document the outcome in the 2023 Transmission Annual Planning Report.

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. We are currently performing assessments to provide further insights on network investments required to unlock the supply potential of the REZs in South Australia.

In the 2022 ISP[42], the South East SA REZ expansion project and the Mid North SA REZ expansion project are required in the late 2020s in the *Hydrogen Superpower* scenario, and early 2030s in the *Step Change* scenario to facilitate the connection of generation within these REZs. AEMO requires preparatory activities to be undertaken for stage 1 of the South East SA REZ expansion project and stage 1 of the Mid North SA REZ Expansion project

Given the continuing high level of interest in new generator connections in South Australia, we consider that the future developments identified in the 2022 ISP could be needed much earlier than indicated. We have developed transmission projects to manage this risk.

Future contingent projects could include stringing 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 installation of additional dynamic reactive support if needed to improve dynamic voltage stability.

The 2022 ISP also forecast a need to alleviate constraints between Robertstown, Davenport and Adelaide in 2033-34 (*Step Change*) and 2028-29 (*Hydrogen Superpower*). To meet this potential need if confirmed we may be required to pursue a future 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 identified 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.

Reverse power flows at a small number of connection points are forecast to exceed their existing reverse power capability by about 2027. These include:

- Baroota

  Potential solutions: require SA Power Networks to limit reverse power flows to no more than then existing limit of 10 MVA, and consider the feasibility of applying a reverse flow cyclic transformer rating
- Mount Barker/Mount Barker South

  Potential solutions: require SA Power Networks to limit reverse power flows under prior transformer outage conditions, and consider the feasibility of applying reverse flow cyclic transformer ratings
- Port Lincoln Terminal

  The commissioning of Eyre Peninsula Link will resolve this forecast constraint by removing the need for Port Lincoln Terminal to be operated in islanded condition under single prior outage conditions.

Similar solutions are forecast to be needed to manage reverse power flows at a range of other connection points beyond 2027. We continually monitor updates in reverse power flow forecasts for all connection points, enabling us to ensure implementation of appropriate reverse power flows management by the time it is required at each connection point.

[42] *AEMO, https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp*

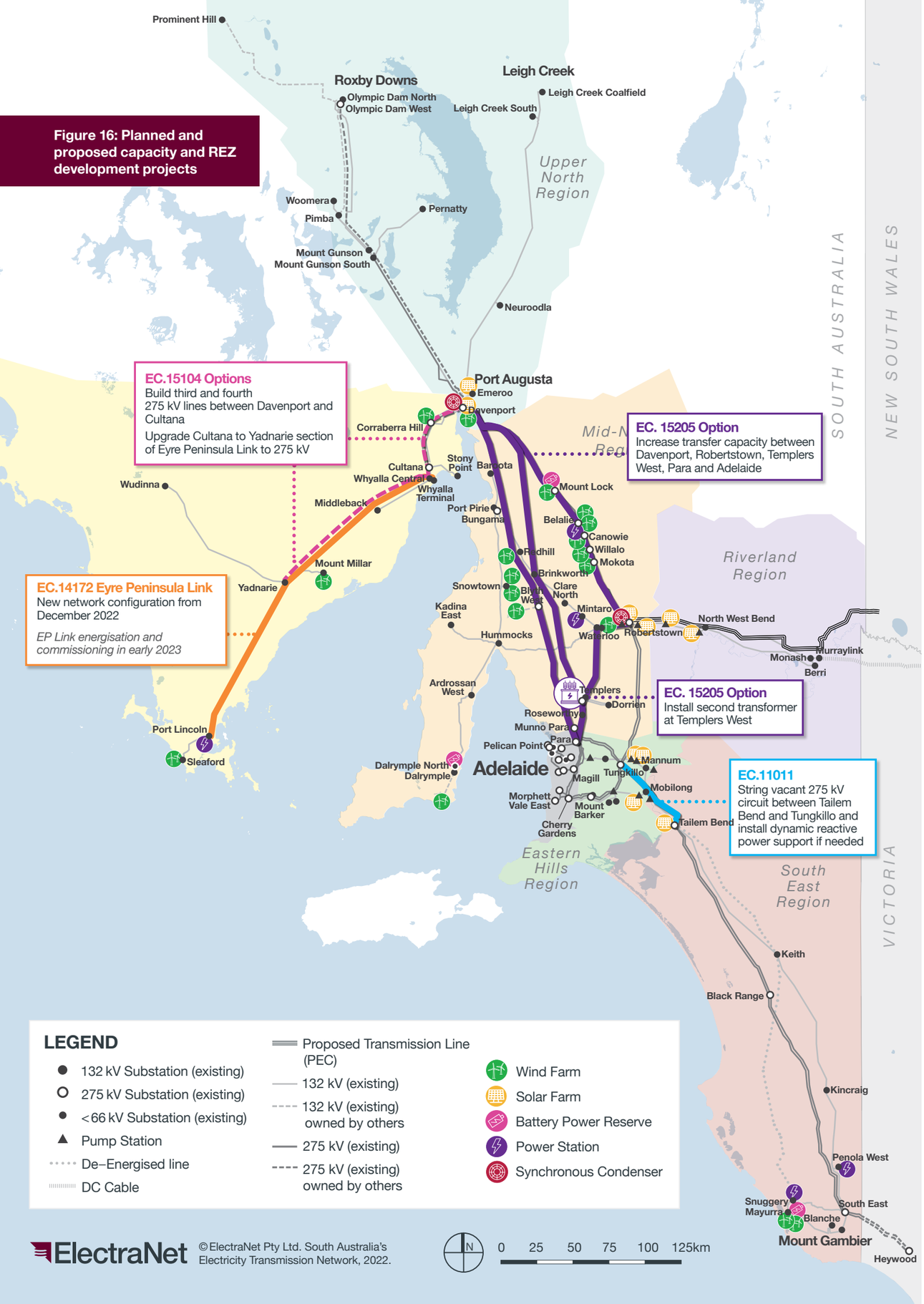


Table 19: Projects committed or proposed to meet capacity or REZ development needs

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14172 Eyre Peninsula Link Estimated cost: **$300-350 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	January 2023
EC.15104 Eyre Peninsula upgrade Estimated cost: **$50-150 million** Status: **Being proposed as a contingent project in the 2024-2028 regulated period** 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: **If required this would be triggered as a contingent project by a future AEMO ISP** 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.14085 Gawler East Connection Point Estimated cost: **$6-10 million (transmission component only)** Status: **Proposed** Cut into the Para to Roseworthy 132 kV line and create a 132 kV connection point for a new 132/66/11 kV, 1 x 25 MVA transformer substation	Mid North	Capacity Augmentation	2029 – 2033 (Depending on local load growth)
EC.15112 Heywood Interconnector Dynamic Voltage Stability Increase Estimated cost: **$30-60 million** Status: **To be considered for proposal as a contingent project in 2029 - 2033** Install dynamic reactive support at Tailem Bend substation, to firm up import and export capability across Heywood interconnector, especially if needed to cater for early coal retirements in Victoria, if not addressed by other developments. ElectraNet envisages that this project will impact inter-regional transfer	Main Grid	Augmentation	2029 – 2033

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15205 Increase Transfer Capacity Between Robertstown, Davenport and Adelaide Estimated cost: **$200-250 million** Status: **If required this would be triggered as a contingent project by a future AEMO ISP** 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	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: **If required this would be triggered as a contingent project by a future AEMO ISP** 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: **If required this would be triggered as a contingent project by a future AEMO ISP** 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

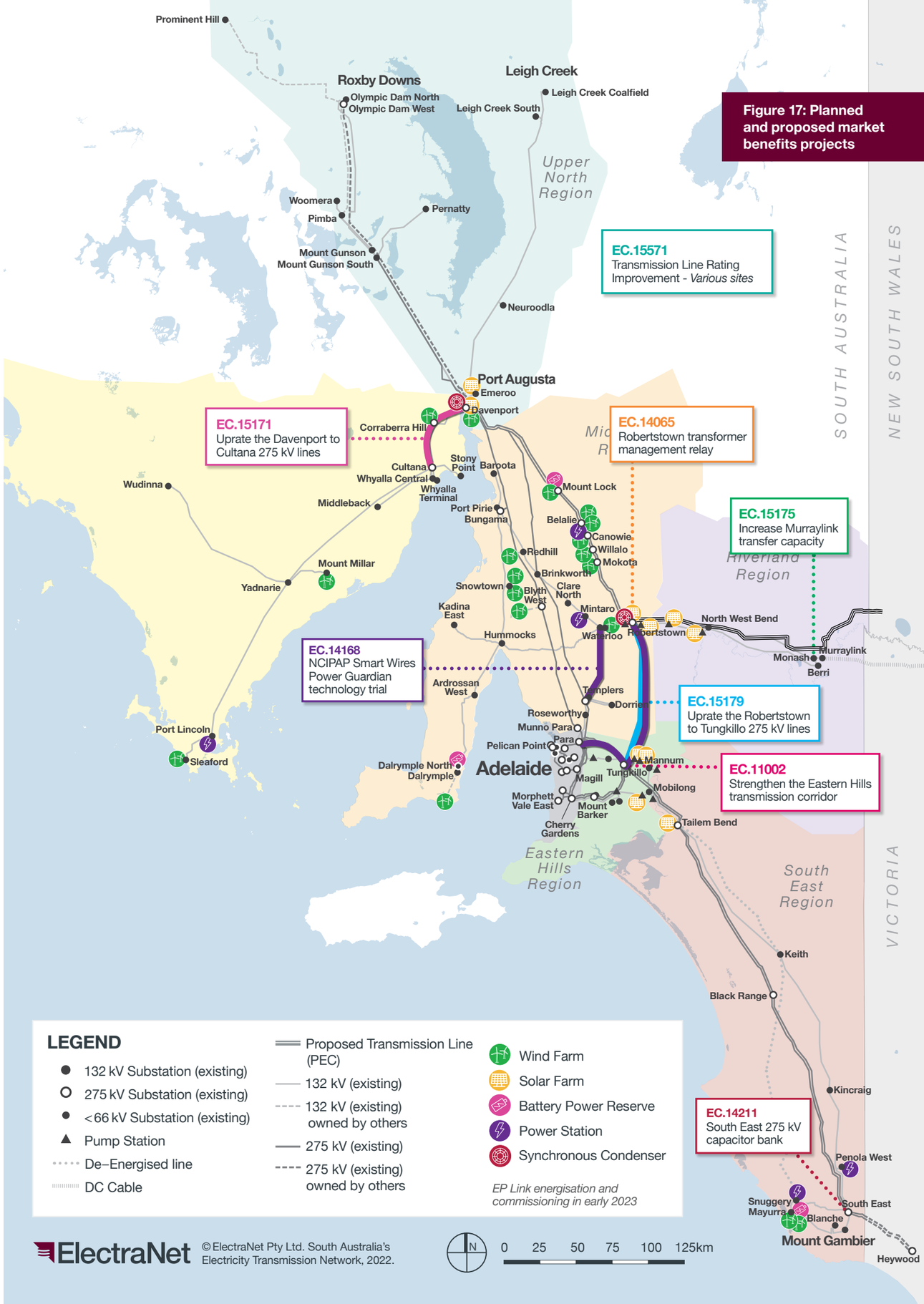
ElectraNet monitors congestion on the South Australian transmission system (chapter 4). We also consider information regarding future likely generator and load connections, along with AEMO's ISP, to predict new constraints that may develop in future years.

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 plan to complete projects that form part of our 2018-19 to 2022-23 NCIPAP and we propose several projects for inclusion in our 2023-24 to 2027-28 NCIPAP (Table 20 and Figure 17).

Table 20: 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: **$5-7 million** Status: **Committed** 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 ElectraNet envisages that this project will impact inter-regional transfer	South East	Market benefits (NCIPAP) Augmentation	November 2022
EC.14168 NCIPAP Smart Wires Power Guardian Technology Trial Estimated cost: **$5-7 million** Status: **Committed** 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. The Project's planned asset in service date of October 2021 in the 2021 TAPR was delayed due to technical difficulties	Mid North	Market benefits (NCIPAP) Augmentation	May 2023
EC.11002 Strengthen the Eastern Hills transmission corridor Estimated cost: **$5-7 million** Status: **Committed** 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 (NCIPAP) Augmentation	May 2023
EC.14065 Robertstown Transformer Management Relay Estimated cost: **Less than $1 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 2023
EC.15171 Uprate Davenport - Cultana 275 kV lines Estimated cost: **$1-2 million** Status: **Included in our 2023-24 to 2027-28 NCIPAP submission** Alleviate forecast congestion between Cultana and Davenport by removing plant and equipment 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 –2025

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15175 Increase Murraylink transfer capacity Estimated cost: **$5-7 million** Status: **Included in our 2023-24 to 2027-28 NCIPAP submission** Alleviate forecast congestion between Cultana and Davenport by removing plant and equipment 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	Riverland	Market benefits (NCIPAP) Augmentation	2025 –2026
EC.15179 Robertstown - Tungkillo 275 kV Line Uprating Estimated cost: **$2 - 3 million** Status: **Included in our 2023-24 to 2027-28 NCIPAP submission** Increase the network's capability between the termination point of Project EnergyConnect and the greater Adelaide region by uprating Robertstown to Tungkillo and Robertstown to Para 275 kV lines from T100 to T120 rating. This will enhance Project EnergyConnect's ability to support new entrant renewables in South Australia, resulting in lower wholesale prices for customers. ElectraNet envisages that this project will impact inter-regional transfer	Riverland	Market benefits (NCIPAP) Augmentation	2023 –2024
EC.15571 Transmission Line Rating Improvement Estimated cost: **$5-7 million** Status: **Included in our 2023-24 to 2027-28 NCIPAP submission** 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 –2025



7.7 Network asset retirements and replacements

ElectraNet carries out projects to address needs that arise from planned retirements of assets, for example due to condition (Table 21).

Prior to 30 January 2018 projects to address replacement needs were not required to be subjected to the RIT-T.

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.[43]

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

Table 21: 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: **$5-7 million** Status: **Committed** 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	April 2023
EC.15320 Para SVC 2 Transformer Emergency Replacement Estimated cost: **$11-13 million** Status: **Committed** Replace the Para SVC 2 transformer and auxiliary equipment that was damaged by a transformer fire in January 2022	Metro	Asset condition and performance Asset renewal	September 2023
EC.15321 TIPS IMB300 CT Replacement Estimated cost: **$11-13 million** Status: **Planned** Remove and replace 38 sets of current transformers at TIPS A and B switchyards that have been identified as high risk of failure	Metro	Asset condition and performance Asset renewal	December 2023
EC.14182 South East SVC Computer Control System Replacement Estimated cost: **$7-10 million** Status: **Planned** Replace the computer control system for the SVC 1 and SVC 2 at South East substation that has been assessed as being end of their life cycle, requiring replacement during 2023-24 to 2027-28 regulatory control period We plan to commence a RIT-T for this project in 2022	South East	Asset condition and performance Asset renewal	November 2025
EC.14077 Mannum Transformer #1 and Secondary System Replacement Estimated cost: **$6-8 million** Status: **Planned** Replace transformer #1 and secondary systems at Mannum substation that has been assessed to be at the end of their technical life with a corresponding high risk of failure, with a new 25 MVA 132/33 kV transformers (nearest ElectraNet standard size) Note that Mannum transformer #2 was replaced in 2021 when the transformer failed	Eastern Hills	Asset condition and performance Asset renewal	April 2026
EEC.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 2028-29 to 2023-33 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.15239 F1803 Hummocks - Ardrossan West 132kV Line Refurbishment to 2027-28 Estimated cost: **$30-35 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 the asset life We plan to initiate a RIT-T prior to commitment	Mid North	Asset condition and performance Asset renewal	2024-2028
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.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	June 2023
EC.14084 Line Conductor and Earthwire Refurbishment 2018-19 to 2022-23 Estimated cost: **$24-28 million** Status: **Planned** Program to replace transmission line conductors and earthwire to extend the life of seven 132 kV transmission lines in the Mid North and Riverland regions: • 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 We plan to commence a RIT-T for this project in 2022	Mid North and Riverland	Asset condition and performance Asset renewal	July 2025

[43] *Transmission Annual Planning report, https://www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/*

Project Description	Region	Constraint driver and investment type	Asset in service
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	Various	Asset condition and performance Asset renewal	June 2028
EC.14046 AC Board Replacement 2018-19 to 2022-23 Estimated cost: **$25-30 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	August 2027
EC.15043 AC Board Unit Asset Replacement 2023-24 to 2027-28 Estimated cost: **$8-14 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.15060 Circuit Breakers Unit Asset Replacement 2023-24 to 2027-28 Estimated cost: **$14-16 million** Status: **Proposed** Replace and improve 24 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

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15069 Circuit Breakers Unit Asset Replacement 2028-29 to 2032-33 Estimated cost: **$6-10 million** Status: **Proposed** Replace and improve 24 circuit breakers at 13 substations across the South Australian 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, switch boards 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 existing 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 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 condition of its network assets to ensure that they are suitable to support the forecast demand. 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 derate any of its assets.

7.9 Grouped network asset retirements, deratings and replacements

Various programs of work that exceed $7 million for grouped network asset retirement and replacement are proposed over the 10-year planning period (Table 22).

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

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

Table 22: 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.14032 Instrument Transformer Unit Asset Replacement 2018-19 to 2022-23 Estimated cost: **$15-17 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, Pimba, 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.14047 Transformer Bushing Unit Asset Replacement 2018-19 to 202223 Estimated cost: **$10-14 million** Status: **Committed** Replace transformer bushings that have been assessed to be at the end of their technical or economic lives on 20 transformers across 12 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, Robertstown, Yadnarie, Snuggery, South East, Parafield Gardens West and Para The number of transformers requiring bushings to be replaced has increased from 16 to 20, as a result of detailed condition assessment of selected transformer bushings following the failure of similar transformer bushings. We published a PACR on 11 December 2018, concluding the RITT for this program of work[44].	Various	Asset condition and performance Asset renewal	November 2023
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 RITT for this program of work[46]	Various	Asset condition and performance Asset renewal	July 2024
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, Davenport, Dorrien, LeFevre, Magill, Middleback, Monash, Mount Gambier, Para, Penola West, Robertstown, Snuggery, Tailem Bend, Torrens Island A, Torrens Island B, Yadnarie and Port Lincoln We published a PACR on 18 November 2019, concluding the RITT for this program of work[47]	Various	Asset condition and performance Asset renewal	September 2024
EC.15120 Instrument Transformer Unit Asset Replacement 2023-24 to 2027-28 Estimated cost: **$16-20 million** Status: **Proposed** Replace 25 voltage transformers and 75 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: **$8-12 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

[44] The Managing the Risk of Transformer Bushing Failure PACR is available from www.electranet.com.au/ projects/transformer-bushing-replacements/.

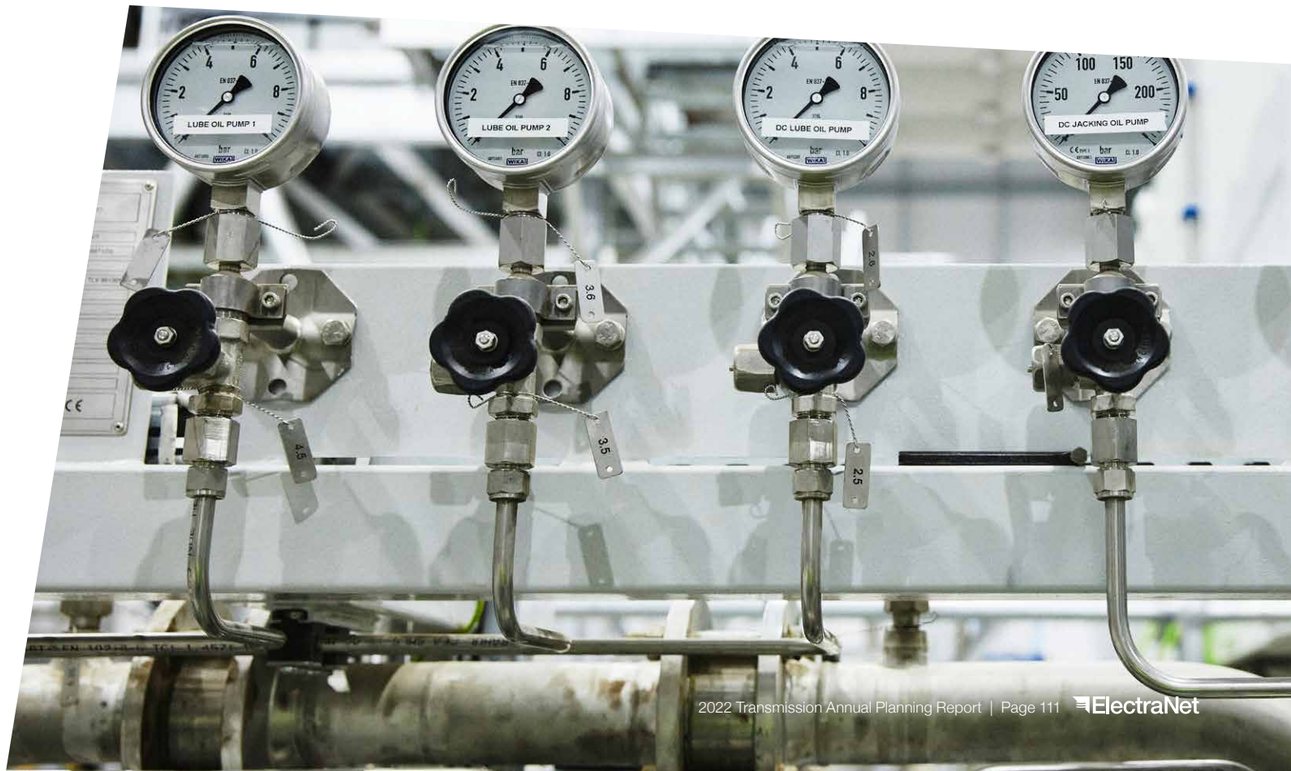
[45] The Managing the Risk of Instrument Transformer Failure PACR is available from www.electranet.com.au/projects/managing-the-risk-of-instrument-transformer-failure-project/.

[46] The Managing the Risk of Protection Relay Failure PACR is available from www.electranet.com.au/projects/managing-the-risk-of-protection-relay-failure/

[47] The Managing the Risk of Isolator Failure PACR is available from www.electranet.com.au/projects/isolator-replacement-and-refurbishment-project/.

Project Description	Region	Constraint driver and investment type	Asset in service
EC.15233 Transmission Line Insulation System Replacement 2023-24 to 2027-28 Estimated cost: **$30-35 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.15242 Transformer Bushing Unit Asset Replacement 2023-24 to 2027-28 Estimated cost: **$8-12 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.15397 Isolator Unit Asset Replacement 2028-29 to 2032-33 Estimated cost: **$40-45 million** Status: **Proposed** Replace 80 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
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

Project Description	Region	Constraint driver and investment type	Asset in service
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
EC.15214 Protection Signal Equipment Replacement Stage 1 Estimated cost: **$6-8 million** Status: **Proposed** Replace protection signalling equipment 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



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 $7 million (Table 23).

Further details, including for projects with a cost less than $7 million, are available from our Transmission Annual Planning Report web page.

Table 23: Committed and proposed security and compliance projects

Project Description	Region	Constraint driver and investment type	Asset in service
EC.14131 Motorised Isolator LOPA Improvement Cost: **$18-22 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	November 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.15220 Substation Security Fencing Replacement 2024-2028 2023-24 to 2027-28 Estimated cost: **$7-10 million** Status: **Planned** Replace high voltage security fencing and gates located at eleven substations that have been assessed to be at the end of their technical and/or economic lives and require replacement to prevent unauthorised access	Various	Safety Asset renewal	2024 – 2028
EC.15235 Transmission line anti-climb installation 2023-24 to 2027-28 Estimated cost: **$20-25 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.15399 Substation Technology System Cybersecurity Uplift 2024-2028 Estimated cost: **$14-18 million** Status: **Proposed** Replace and upgrade substation technology assets identified as being susceptible to cyber-attack breaches by replacing relevant equipment as well and uplifting cyber security of network and intelligent devices. This work will be carried out progressively during the 2024-2028 regulatory period across 57 high risk substations	Various	Safety Asset renewal	2024 – 2028
EC.15401 Happy Valley site drainage replacement Estimated cost: **$6-10 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	Safety Asset Renewal	2024 – 2028
EC.15496 Substation LAN Replacement and Cybersecurity Uplift 2028-2033 Estimated cost: **$8-12 million** Status: **Proposed** Replace and upgrade substation technology assets identified as being susceptible to cyber-attack breaches by replacing relevant equipment as well and uplifting cyber security of network and intelligent devices at 19 substations. This cyber-security uplift continues the work undertaken in 2023-2028 period	Various	Safety Asset renewal	2029 – 2033
EC.15231 – Transmission line anti-climb 2028-29 to 2032-33 Estimated cost: **$30-40 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

Appendices

Appendix A: Summary of changes since the 2021 Transmission Annual Planning Report

In this appendix we provide an analysis and explanation of forecast demand, and other aspects of the 2022 Transmission Annual Planning Report (TAPR) that have changed significantly from the 2021 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 2021 and 2022 TAPR	Analysis and explanation for the significant change
1.1	South Australia's journey towards 100% renewable electricity generation	Figure 1 has been updated based on the latest available figures Section 1.1 has been updated to reflect current Federal and State government targets on net zero emission and renewable 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 section has been updated	We have updated information in this section to report on our provision for fast frequency response
1.2	Network Vision, future directions and key priorities	This section has been updated	We have updated the information in this section to report on our provision for fast frequency response
1.3.4	Inertia	This section has been retitled	We have updated the information in this section to report on our provision for fast frequency response
1.3.6	Climate Change	This is a new section in 2022	We have added this section to reflect the risk of climate change to our electricity transmission network
2.1	Integrated System Plan	The information in this section has been updated and consolidated	We have updated the information and consolidated contents of this section to include our ISP projects, REZ and a subsection for *Hydrogen Superpower* scenario
2.1.3	Generation development in the *Hydrogen Superpower* scenario	This is a new section in 2022	We have included this section to provide data and analysis of forecast levels of renewable generation for the *Hydrogen Superpower* scenario in the ISP
2.2	2021 System Security Reports	The information in this section has been updated and consolidated	We have updated the information and consolidated contents of this section to include System Security Reports on System Strength, Inertia, NSCAS
2.3.1	Recommendations and findings relating to South Australia	The information in this section has been updated	Information presented on protected event and how this is managed, and ramping events associated with DER and renewables
3.1	South Australian electricity demand	Figure in Section 3.1 has been updated to include data for 2021- 22	This update figure reflects the latest available information
3.3	Demand forecasts	Figure 7: AEMO's 2022 ESOO Central/Step Change and 2021 ESOO Central forecasts updated with AEMO's 2023 ESOO	This update figure reflects the latest available information
3.3.1	Potential key drivers of demand	This section has been updated	We have updated this section to describe potential drivers that could in future increase demand levels higher than the current forecasts
3.3.2	Demand forecasts in the *Hydrogen Superpower* scenario	This is a new section in 2022	This section was included to provide analysis in comparing the AEMO Central and *Hydrogen Superpower* demand forecasts
3.4.1	Weather conditions during summer	The information in this section has been updated	We have updated this section to reflect the latest available information

Section	Section Name	Significant changes between the 2021 and 2022 TAPR	Analysis and explanation for the significant change
3.4.2	State-wide demand review	The information in this section has been updated	We have updated this section to reflect the latest available information
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 We have provided some insights on the 2022 Connection Point maximum demand forecast
3.4.4	Connection point reverse power flow review	This is a new section in 2022	We have provided high level insights on the impact of reverse power flows on connection points
4.2	Transmission system constraints in 2021	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 was at least $150,000 during 2021
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 2022 ISP Step Change scenario We have provided brief discussion on future constraints
4.4	Potential projects to enable load growth	This section has been retitled and updated	We have provided information on potential projects to address future constraints
5	Connection opportunities and demand management	The information in this section has been updated	We have updated this section based on AEMO's 2022 ESOO
5.1	New connections and withdrawals	The information in this section has been updated	We have provided information on new generation connections and withdrawals based on AEMO's generation information
5.2.4	Opportunities to connect to Project EnergyConnect	The information in this section has been updated	We have provided information and a source of information for future update
5.3	Connection opportunities for load customers	The information in this section has been updated	We have updated our assumptions for the studies performed
5.4	Summary of connection opportunities	The information in this section has been updated	We have performed high-level assessment of the ability of existing transmission nodes and connection points to accommodate new generation and load connections
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	We have performed high-level assessment of the ability of existing transmission nodes and connection points to accommodate new generation and load connections
5.5	Summary of connection opportunities	The information in this section has been updated	We have provided information on proposed, committed and recently energised new connection points
5.6	Projects for which network support solutions are being sought or considered	The information in this section has been updated	We have provided information on projects where we plan to seek proposals for network support solutions

Section	Section Name	Significant changes between the 2021 and 2022 TAPR	Analysis and explanation for the significant change
6.1	Recently completed projects	The following projects have been completed in the last 12 months: • EC.15307 Para SVC 1 Transformer Emergency Replacement • EC.11749 AC Board Replacement 2013 – 2018 • EC.14211 South East 275 kV Capacitor Bank	We have updated the information to reflect the status of projects completed up until 31 October 2022
6.2	Committed projects	Updated to include the following projects: • EC.14168 NCIPAP Smart Wires Power Guardian Technology Trial - planned asset in service date of October 2021 in the 2021 TAPR was delayed due to technical difficulties • EC.14049 Leigh Creek South transformer replacement • EC.11002 Strengthen the Eastern Hills transmission corridor • EC.15320 Para SVC 2 Transformer Emergency Replacement	We have updated the information to reflect committed projects as of 31 October 2022
6.3	Pending Projects	The table of pending projects has been removed	We currently have no pending projects
7	Transmission system development plan	Table and Figure in this section 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 in this section 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	Table in this section has been updated	We have updated this information to reflect the latest results of our ongoing project and planning processes including the cost estimates and timings of projects
7.4	System security, power quality and fault levels	Table in this section has been updated	We have updated this information to reflect the latest results of our ongoing project and planning processes including the cost estimates and timings of projects
7.5	Capacity and Renewable Energy Zone Development	Updated to include the following projects: • EC.14085 Gawler East Connection Point • EC.15112 Heywood Interconnector Dynamic Voltage Stability Increase	We have updated this information to reflect the latest results of our ongoing project and planning processes including the cost estimates and timings of projects
7.6	Market benefit opportunities	Updated to include the following projects: • EC.14168 NCIPAP Smart Wires Power Guardian Technology Trial - planned asset in service date of October 2021 in the 2021 TAPR was delayed due to technical difficulties • Increase Rating of 275 kV East Circuit	We have updated this information to reflect the latest results of our ongoing project and planning processes including the cost estimates and timings of projects. We have added Increase Rating of 275 kV East Circuit to optimise our 2018-19 to 2022-23 NCIPAP

Section	Section Name	Significant changes between the 2021 and 2022 TAPR	Analysis and explanation for the significant change
7.7	Network asset retirements and replacements	Updated to include the following projects: • EC.15321 TIPS IMB300 CT Replacement • EC.15320 Para SVC 2 Transformer Emergency Replacement • EC.14182 South East SVC Computer Control System Replacement	We have updated this information to reflect the latest results of our ongoing project and planning processes
7.9	Grouped network asset retirements, deratings and replacements	Updated to include the following projects: • EC.15233 Transmission Line Insulation System Replacement 2023-24 to 2027-28 • EC.15214 Protection Signal Equipment Replacement Stage 1	We have updated this information to reflect the latest results of our ongoing project and planning processes including the cost estimates and timings of projects
7.10	Security and compliance projects	Updated to include the following projects: • EC.15220 Substation Security Fencing Replacement 2024-2028 • EC.15399 Substation Technology System Cybersecurity Uplift 2024-2028 • EC.15496 Substation LAN Replacement and Cybersecurity Uplift 2028-2033	We have updated this information to reflect the latest results of our ongoing project and planning processes including the cost estimates and timings of projects
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 have proposed for the 2023-24 to 2027-28 regulatory 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

We undertake 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. This includes working 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.[48]

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.

[48] *See www.energynetworks.com.au*

B1.6 Joint planning meetings

We have 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.

SA Energy Transition Steering Group

ElectraNet and SA Power Networks 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.

Network Strategy Committee

The Network Strategy Committee is an Executive level forum that facilitates consideration of alignment on key changes impacting on the network. It ensures alignment of long-term vision and strategies and oversee coordination of joint planning.

Routine joint planning activities

The purpose of routine joint planning is to deliver lowest long run costs by identifying efficient network solutions across both transmission and distribution. We hold joint planning meetings every two months, attended by planning personnel from both organisations, including discussion of items such as:

- Demand forecasting
- Connection point planning
- Network connections
- AEMO joint planning and the ISP
- System security matters and initiatives
- Network operations
- Working group status reporting.

Voltage Control Working Group

The Voltage Control Working Group reports to the regular Joint Planning meeting between ElectraNet and SA Power Networks. Its purpose is to coordinate cost effective reactive power and voltage control management outcomes for South Australian electricity customers by developing joint voltage management strategies and plans that efficiently support the distributed energy future.

B1.7 Other joint planning engagements

For effective network planning, ElectraNet also engages in joint planning activities with:

- AEMO (in their roles as National Planner and Jurisdictional Planning Body for the Victorian transmission system)
- TransGrid.

B1.8 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)

  Through engagement with AEMO and other TNSPs through the Executive Joint Planning Committee, Joint Planning Committee, and joint planning meetings we have provided advice about constraints and limitations in the South Australian electricity transmission system, and scopes and costs for projects that could address those limitations. AEMO used that information in the modelling that underpinned the 2022 ISP.
- Project EnergyConnect (sections 1.3.1, 2.1.2, 6.2 and 7.3)

  We continue to engage with AEMO and TransGrid on project implementation planning for Project EnergyConnect.
- Transmission Network Voltage Control (section 2.2.3, 7.1 and 7.4)

  We are engaged with SA Power Networks in joint planning for the Transmission Network Voltage Control Project to ensure the identified need is appropriately defined, and to develop the suite of transmission and distribution solutions available to meet the identified need.

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[49].

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.[50] 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.

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

[50] 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.

C2 Obligations relating to capital expenditure

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.[51]

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[52]
- 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.[53]

[51] 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.

[52] National Electricity Rules, Schedule 5.1

[53] 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. [54]

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.

[54] *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:

- 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.[55]

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

[55] *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.

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[56]
- 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

[56] *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 2022 Transmission Annual Planning Report with the requirements of clause 5.12.2(c) of version 187 of the Rules (the latest version at time of writing).

Summary of requirements			Section
The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[57] 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[58]
	(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 deratings 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 derated, 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 derated; and	
	(iv)	if the date to retire or derate 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 *derated* across more than one location;	
	(iii)	to be retired or *derated* 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 derated, 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 derated; and	
	(viii)	if the calendar year to retire or derate 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	
(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	

Summary of requirements			Section
The Transmission Annual Planning Report must be consistent with the TAPR Guidelines[57] and set out:			
(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 *general 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
(9A)	the analysis of the operation of, and any known or potential interactions between:		
	(i)	any *emergency frequency control schemes*, or emergency controls place under clause S5.1.8, on its *network*; and	Section 4.5
	(ii)	*protection systems* or *control systems of plant connected* to its *network (*including consideration of whether the settings of those systems are fit for purpose for the future operation of its *network*), undertaken under clause 5.12.1(b)(7), including a description of proposed actions to be undertaken to revise those schemes, controls or systems, or to address any adverse interactions;	
(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

[57] *AER TAPR Guidelines, www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/transmission-annual-planning-report-guidelines*

[58] *ElectraNet, www.electranet.com.au/what-we-do/network/transmission-annual-planning-reports/*

Appendix E: Contingent projects

Table 25: Contingent projects for the 2019-23 regulatory control period

Project	Trigger[59]	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	Commissioning	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	Commissioned	Sections 1.1.1; 1.3.3, 5.2.3 and 7.1
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, 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 2018-23 regulatory control period. Project transferred to AEMO's Integrated System Plan.	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 2018-23 regulatory control period. Project transferred to AEMO's Integrated System Plan.	Section 7.5

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

- *Determination (if applicable) by the AER under clause 5.15A of the Rules (or equivalent process) that the proposed investment satisfies the RIT-T(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.*

Table 26: Contingent projects in the Revenue Proposal for the 2024-28 regulatory control period

Project	Trigger[60]	Current status	Reference
Eyre Peninsula Upgrade Upgrade of the 132 kV Eyre Peninsula Link between Cultana and Yadnarie to 275 kV and/or augmentation of power transfer capacity between Davenport and Cultana and/or Cultana and Whyalla and/or Cultana and Stony Point.	Commitment for additional load from one or more customers to connect to the transmission network with aggregate load sufficient to cause the: a) Cultana 275/132 kV transformers to exceed their thermal limit of 200 MVA; or b) Whyalla Central 132/33 kV transformers to exceed their thermal limit of 120 MVA; or c) Whyalla Central to Cultana 132 kV lines to exceed their thermal limit of 117 MVA; or d) Cultana to Stony Point 132kV line to exceed its thermal limit of 144 MVA; or e) Davenport to Cultana 275 kV lines to exceed their thermal limit of 597 MVA. Successful completion of the South Australian Energy Transformation RIT-T with the identification of a preferred option or options: a) Demonstrating positive net market benefits and/or b) Addressing a reliability corrective action	Proposed contingent	Section 7.5
Network Power Quality Remediation Installation of harmonic filters, reactors or STATCOMs as required	ElectraNet obtains measurements that demonstrate the voltage harmonics at any one or more of the sites listed below exceed those specified by their planning levels under NER cl. S5.1a.6 in accordance with electromagnetic compatibility standard AS/NZS IEC 61000.3.6:2012. 1. South East 2. Tailem Bend 3. North West Bend 4. Monash 5. Mount Gunson 6. Pimba ElectraNet demonstrates that the voltage harmonic distortion causing the planning levels under NER cl. S5.1a.6 to be breached can be attributed to the extent practicable to the transmission network rather than to one or more Network Users or to a Distribution Network Service Provider.	Proposed contingent	Section 7.4
Project EnergyConnect Upgrade Integration of battery energy storage projects and other technologies to extend the capability of Project EnergyConnect and/or Heywood interconnector	Successful completion of RIT-T with an identified need to increase the capacity of either the combined interconnector limits across Project EnergyConnect and Heywood or an increase in the capability of Project EnergyConnect.	Proposed contingent	Section 7.3

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

- *Determination (if applicable) by the AER under clause 5.15A of the Rules (or equivalent process) that the proposed investment satisfies the RIT-T(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.*

Appendix F: Assumptions considered in ElectraNet's planning process - potential future generator retirements and new generator and battery connections

Table 27: Assumptions considered in ElectraNet's planning process, including potential future generator retirements and new generator and battery connections

	Capacity	Status	Location on Map
Potential New Storage			
Lincoln Gap WF BESS	10MW	Anticipated	Corrabera Hill
Tailem Bend Battery Project	50 MW	Anticipated	Tailem Bend
Torrens Island BESS	250 MW	Anticipated	Torrens Island
Potential New Solar Farm			
PAREP Solar Farm	79 MW	Committed	Davenport
Tailem Bend Stage 2 Solar Farm	105 MW	Committed	Tailem Bend
Potential New Wind Farm			
Lincoln Gap Wind Farm – stage 2	86 MW	Commissioning	Corraberra Hill
PAREP Wind Farm	210 MW	Committed	Davenport
Goyder Wind Farm	465 MW	Publicly announced	Robertstown
Potential New Thermal Power Station			
Snapper Point Power Station	154 MW	Commissioning	Pelican Point
Bolivar Power Station	123 MW	Anticipated	SAPN northern – Parafield Gardens West
Retiring/Mothballed Generation			
Osborne (gas)	180 MW	In service -announced withdrawal	New Osborne
TIPSA 3 (gas)	120 MW	In service -announced withdrawal / mothballed	Torrens Island
Wattle Point (wind)	91 MW	Planned	Dalrymple
Cathedral Rocks (wind)	66 MW	Planned	Sleaford
Dalrymple(BESS)	30 MW	Planned	Dalrymple
Dry Creek GT1,2,3 (gas)	156 MW	Planned	Dry Creek
Mintaro GT (gas)	90 MW	Planned	Mintaro
Snuggery 1 (gas)	63 MW	Planned	Snuggery
Morgan To Whyalla Pipeline No 1 PS And Water Filtration Plant (solar)	6 MW	Planned	MWPS1
Hallett Power Station (12 units) (gas) GT2-3 GT2-4 GT3-1 GT2-2 GT1-4 GT2-1 GT3-2 GT4-2 GT1-2 GT4-1 GT3-3 GT3-4	240 MW	Planned	Canowie

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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